1.0 INTRODUCTION

TransCanada Keystone Pipeline, LP (Keystone) applied to the U.S. Department of State (DOS) for a Presidential Permit for the proposed construction, connection, operation, and maintenance of a pipeline and associated facilities at the United States border for importation of crude oil from Canada. The Keystone application is for its proposed Keystone XL Project (the proposed Project). Keystone also filed a right-of-way application under Section 28 of the Mineral Leasing Act of 1920 (MLA), as amended with the Bureau of Land Management (BLM) for the proposed Project across federal lands. DOS served as the lead federal agency for the environmental review of the proposed Project under the National Environmental Policy Act (NEPA), and issued a draft environmental impact statement (EIS) for public review on April 16, 2010. The public comment period for the draft EIS closed on July 2, 2010.

After the draft EIS was issued, new information and additional information became available on the proposed Project and on issues and resources related to the potential impacts of the proposed Project. To provide the public with the opportunity to review this information and to ensure openness and transparency in the NEPA environmental review process of the proposed Project, DOS has issued this supplemental draft EIS (SDEIS).

The draft EIS was developed in compliance with the scoping process required under NEPA and in compliance with the Council on Environmental Quality (CEQ) NEPA regulations. It includes relevant issues raised by the public and the agencies during the scoping period. DOS received thousands of comments on a wide variety of topics addressed in the draft EIS during the draft EIS comment period. Some commenters expressed concern that the draft EIS did not provide a sufficient analysis of the impacts of the proposed Project and requested that DOS issue an SDEIS for public review.

As part of its continuing evaluation of the adequacy of the draft EIS, DOS analyzed the new and additional information that became available after the draft EIS was issued and made a preliminary determination that there are no significant new circumstances or information concerning the proposed Project or its potential impacts not already considered in the draft EIS. The analysis further noted that while the range of alternatives to the proposed action considered in the draft EIS was sufficient to meet the requirements of NEPA, additional alternatives should be considered in response to public comments on the draft EIS. DOS therefore determined that submitting the portions of the EIS that were revised to address the new and additional information and to address related comments on the draft EIS for public and agency review would further the purposes of NEPA. As a result DOS prepared and issued this SDEIS.

The SDEIS has been prepared and circulated in compliance with CEQ NEPA regulations and DOS guidelines (*Using Existing Environmental Analyses*). It includes copies of new reports and other documents relevant to the proposed Project and revisions to portions of the draft EIS.

To focus public attention on the topics that DOS determined would be of value for additional review, the SDEIS provides only information directly or indirectly related to those topics and does not include all sections that were presented in the draft EIS. However, the SDEIS incorporates the draft EIS by reference in compliance with CEQ NEPA regulations. The draft EIS is available for download from the DOS Keystone XL Project related website (www.keystonepipeline-xl.state.gov). The SDEIS addresses the following key issues:

Revised information on proposed Project facilities; design, construction and maintenance, regulatory requirements; and potential connected actions

- Information on changes to the proposed Project facilities and construction of those facilities associated with withdrawal of the special permit application by Keystone and incorporation of the 57 Project-specific Special Conditions recommended by the U.S. Department of Transportation, Pipeline and Hazardous Material Safety Administration (PHMSA) that would apply for the lifetime of the proposed Project (e.g., lower maximum throughput and lower operating pressure than in the draft EIS, revised pipe wall thicknesses, change to the distance between mainline valves, and changes to construction procedures addressed by the Special Conditions);
- Relocation of the tank farm from Steele City, Nebraska to Cushing, Oklahoma;
- Revisions to Operations and Maintenance information due to incorporation of the 57 Project-specific PHMSA Special Conditions and in response to comments on the draft EIS, including additional information on the development and review of a Project-specific Emergency Response Plan;
- Two additional non-federal connected actions, the Bakken Marketlink Project and the Cushing Marketlink Project, that were developed after the draft EIS was issued, and the potential impacts of implementation of those projects based on currently available information (the proposed BakkenLink Pipeline Project is currently speculative and therefore not considered a connected action for the purposes of this SDEIS); and
- Additional information on future plans and decommissioning.

Additional information on groundwater, potential spill impacts, alternatives to the proposed Project, and environmental justice considerations

- Additional information on potential impacts to groundwater due to an unintentional release of crude oil from the proposed Project, including additional information on the Northern High Plains Aquifer (NHPAQ) system, which includes the Ogallala aquifer, and the Sand Hills topographic region of Nebraska;
- Assessments of additional potential alternatives developed after the draft EIS was issued, including additional system alternatives, additional route alternatives (including alternative routes developed to avoid or minimize the distances through the Sand Hills topographic region and areas overlying the NHPAQ system), pipeline design alternatives, and alternatives to the locations of aboveground facilities; and
- Expanded information on environmental justice issues in response to EPA comments on the draft EIS.

Additional information on crude oil composition, potential refinery emissions, and greenhouse gas (GHG) and climate change considerations

- Additional information on the composition of the crude oil that would be transported by the proposed Project and comparisons of that crude oil to other crude oils currently being refined in Petroleum Administration Defense District (PADD) II and PADD III and revisions to the Oil Spill Risk Assessment and Environmental Consequences section (that section has also been renamed to “Potential Releases from Project Construction and Operation and Environmental Consequence Analysis”); and

- Additional information on GHG emissions associated with the proposed Project based on information provided in recently completed reports (described below).

The main body of the SDEIS includes portions of sections of the EIS that have been revised to address the new and additional information, and in some cases, the entire section. To provide the proper context for the expanded, updated, and new information relevant to the NEPA environmental review of the proposed Project, the following sections are included in their entirety:

- Section 3.13 (Potential Releases from Project Construction and Operation and Environmental Consequences Analysis); and
- Section 4.0 (Alternatives).

Other sections of the SDEIS provide portions of revised EIS sections relevant to the topics listed above, including expansions of assessments of key environmental concerns that were included in the draft EIS and new information that was developed in response to comments on the draft EIS. Section 1.0 has been reorganized to include new sections for the Presidential Permit review process (Section 1.3) and an overview of the crude oil market (Section 1.4). Sections 1.2 (Purpose and Need), 1.3 and 1.4 of the SDEIS replace Section 1.2 of the draft EIS.

The portions of the EIS that are not included in the SDEIS have not been substantively revised. They will be included in the final EIS with minor revisions, including edits for clarification, corrections of typographical errors, minor expansion of existing information, and updates where appropriate. The final EIS will also include responses to comments on the draft EIS and responses to comments on the SDEIS.

The SDEIS also includes the following documents as appendices:

- A 2010 report prepared by EnSys Energy and Systems, Inc. (EnSys) contracted by the U.S. Department of Energy (DOE), Office of Policy & International Affairs. DOE contracted EnSys to evaluate different North American crude oil transport scenarios through 2030 to assist DOS in better understanding the potential impacts of the presence or absence of the proposed Project on U.S. refining and petroleum imports and also on international markets. The study also assessed global life-cycle GHG impacts of the scenarios evaluated. Although the study is a contractor report and does not necessarily represent the views of any U.S. government agency, it was conducted in close collaboration with and had significant input from DOE. The EnSys report, presented in Appendix A of this SDEIS, was previously made available for public review on the DOS website as described in the notice of availability in the Federal Register on February 14, 2011 (Volume 76, Number 30);

- A 2011 report by ICF International (ICF) that was requested by DOS to assist in addressing concerns relative to GHG emissions. The report provides a detailed review of key studies in the existing literature that address life-cycle GHG emissions of petroleum products, particularly petroleum products derived from WCSB oil sands. The ICF report is presented in Appendix B of this SDEIS;

- A set of 57 Project-specific Special Conditions developed in close consultation with PHMSA. Originally, PHMSA began development of these conditions in consideration of a special permit request from Keystone that, if granted, would have allowed Keystone to operate the proposed Project at a maximum operating pressure higher than that specified in 49 CFR 195.106. On August 5, 2010, Keystone withdrew its application to PHMSA for a special permit. However, DOS continued to work with PHMSA and Keystone to develop Special Conditions in response to comments on the draft EIS regarding pipeline construction, operation, and maintenance.

- Information provided by Keystone in response to a Data Request from DOS regarding proposed construction procedures through the Sand Hills topographic region and consultation with the appropriate experts on the Sand Hills topographic region. This information is presented in Appendix D of this SDEIS; and
- Water well data along the Proposed Keystone XL Project Route that was obtained by the DOS third-party contractor to expand information on existing groundwater conditions along the proposed route as a part of understanding the potential impacts of an unintentional release of crude oil from the proposed Project. This information is presented in Appendix E of this SDEIS.

1.1 OVERVIEW OF THE PROPOSED PROJECT

Keystone proposes to construct and operate a crude oil pipeline and related facilities to transport Western Canadian Sedimentary Basin (WCSB) crude oil from an oil supply hub near Hardisty, Alberta, Canada to destinations in the south central United States, including a new tank farm in Cushing, Oklahoma and delivery points in Nederland (near Port Arthur) and Moore Junction (in Harris County), Texas. In total, the proposed Keystone XL Project would consist of approximately 1,711 miles of new, 36-inch-diameter pipeline, with approximately 327 miles of pipeline in Canada and approximately 1,384 miles in the United States. The proposed Project would cross the international border between Saskatchewan, Canada, and the United States near Morgan, Montana. The proposed Project initially would have a nominal transport capacity of 700,000 barrels per day (bpd) of crude oil. Up to 200,000 bpd of crude oil would be delivered to the proposed Cushing, Oklahoma tank farm, which is in Petroleum Administration for Defense District (PADD) II, with the remainder of the crude oil transported to the delivery points in Texas, which are in the Gulf Coast portion of PADD III. By increasing the pumping capacity in the future, the proposed Project could ultimately transport up to 830,000 bpd of crude oil.

At the time of publication of the draft EIS, Keystone had applied to the U.S. Department of Transportation (USDOT), Pipeline and Hazardous Materials Safety Administration (PHMSA) for consideration of a Special Permit request to operate the proposed Project at a slightly higher pressure than would be allowed using the standard design factor in the regulations. As reported in the draft EIS, the maximum crude oil throughput for that proposed system would have been 900,000 bpd. On August 5, 2010, Keystone withdrew its application to PHMSA for a Special Permit. Therefore the proposed Project would be constructed in accordance with the existing regulatory requirements in 49 CFR Parts 194 and 195 and the set of 57 Special Conditions developed by PHMSA (described further in Sections 2.3 and 3.13.1.1 and presented in Appendix C of this SDEIS). As a result, the maximum throughput of the proposed Project decreased and is currently proposed to be approximately 830,000 bpd.

The proposed Project would primarily deliver WCSB crude oil, which would likely be heavy crude oil based on current market forecasts, to three delivery points in the U.S. that in turn provide access to many other U.S. pipeline systems and terminals. The ultimate destinations of the crude oil beyond these delivery points would not be contracted with Keystone and are not a part of the proposed Project. While the exact destinations of the crude oil that would be transported by the proposed Project are uncertain, there are 15 refineries within the proposed delivery area in Texas that would have direct access to crude oil delivered by the proposed Project (Purvin & Gertz 2009). Those refineries currently process heavy crude oil that is similar in composition to the oil that would be delivered by the proposed Project (Purvin & Gertz 2009).

1.2 PURPOSE AND NEED

The primary purpose and need of the proposed Project is to provide the infrastructure necessary to transport WCSB heavy crude oil from the border with Canada to delivery points in PADD III in response to the market demand of refineries in PADD III for heavy crude oil. This market demand is driven by the need of refiners in PADD III to replace current feed stocks of heavy crude oil obtained from other foreign sources with crude oil from a more stable and reliable source. Keystone currently has firm, long-term contracts to transport 380,000 bpd of WCSB crude oil to existing PADD III delivery points. An additional purpose of the proposed Project is to transport WCSB heavy crude oil to the proposed Cushing tank farm in response to the market demand of refineries in PADD II for heavy crude oil. Keystone has firm contracts to transport 155,000 bpd of WCSB crude oil to Cushing, Oklahoma in the existing Keystone Oil Pipeline Project, which includes the Keystone Mainline and the Keystone Cushing Extension. If the proposed Project is approved and implemented, Keystone would transfer shipment of crude oil under those contracts to the proposed Project. While there is existing transboundary pipeline capacity to accommodate projected additional imports of WCSB crude in the short to medium term, there is extremely limited pipeline transport capacity to move such crude oils to PADD III refineries. As noted in the previous section, the proposed Project would provide an initial capacity of 700,000 bpd to meet the projected market demand for additional WCSB crudes, with the ability to increase to 830,000 bpd by increasing pumping capacity.

DOS evaluated the proposed Project to determine whether approving it and granting a Presidential Permit for "construction, connection, operation, or maintenance at the borders of the United States of facilities for the exportation or importation of petroleum, petroleum products, coal, or other fuels to or from a foreign country" is in the national interest. The Secretary of State has the authority to approve or deny such applications, and to issue such permits on terms and conditions that the Secretary determines are appropriate under EO 13337, as amended. Although the primary focus of DOS is related to the conduct of foreign affairs, in considering the national interest for purposes of applications for Presidential Permits, DOS takes into account many factors, including domestic impacts associated with issuance of a permit, such as environmental, cultural, and economic considerations, consistent with the relevant federal statutes and Executive Orders identified in Sections 1.5 and 1.6 of the draft EIS, and in Section 1.10 of this SDEIS.

In response to comments on the draft EIS, the market analysis relevant to purpose and need has been reorganized in the EIS, and the following section on the Presidential Permit review process (Section 1.3) has been added. The extensive information on crude oil markets is included in this EIS because the United States has a largely unregulated market for obtaining crude oil (the primary use of which is the production of transportation fuel). Thus, understanding the basic dynamics of the crude oil market is key to understanding the potential alternatives to the proposed Project (including the No Action Alternative). In addition, the analysis of the crude oil market has been expanded in response to comments to include scenarios that base projections on alternate policy scenarios, including adoption of more aggressive policies that address climate change by reducing crude oil consumption.

The BLM's purpose and need for the Keystone XL Pipeline Project is to respond to the Keystone application under Section 28 of the Mineral Leasing Act of 1920, as amended (MLA; 30 USC 185) for a right-of-way (ROW) grant to construct, operate, maintain, and decommission a crude oil pipeline and related facilities on federal lands in compliance with the MLA, BLM ROW regulations, and other applicable Federal laws. The BLM will decide whether to approve, approve with modification, or deny issuance of a ROW grant to Keystone for the Keystone XL Pipeline project, and if so, under what terms and conditions. The proposed ROW action appears consistent with approved BLM land use planning.

1.3 PRESIDENTIAL PERMIT REVIEW PROCESS (NEW SECTION)

Consistent with the President's broad discretion in the conduct of foreign affairs, DOS has significant discretion in the factors it examines in making a National Interest Determination (NID). The factors examined and the approaches to their examination are not necessarily the same from project to project. However, previous NID processes can provide insights into the factors DOS is likely to consider in evaluating the present application. Some of the key factors considered in past decisions include the following:

- Environmental impacts of the proposed projects;
- Impacts of the proposed projects on the diversity of supply to meet U.S. crude oil demand and energy needs;
- The security of transport pathways for crude oil supplies to the U.S. through import facilities constructed at the border relative to other modes of transport;
- Stability of trading partners from whom the U.S. obtains crude oil;
- Impact of a cross-border facility on the relations with the country to which it connects;
- Relationship between the U.S. and various foreign suppliers of crude oil and the ability of the U.S. to work with those countries to meet overall environmental and energy security goals;
- Impact of proposed projects on broader foreign policy objectives, including a comprehensive strategy to address climate change;
- Economic benefits to the U.S. of constructing and operating proposed projects; and
- Relationships between proposed projects and goals to reduce reliance on fossil fuels and to increase use of alternative and renewable energy sources.

This list is not exhaustive, and DOS may consider additional factors in the NID process. After publication of the final EIS, the federal agencies identified in EO 13337 (see Section 1.5 of the draft EIS) will have 90 days to provide their input on whether or not approving the proposed Project would be in the national interest. Additionally, DOS specifically intends to solicit public comment on the national interest question during an additional public comment period after publication of this EIS.

1.4 OVERVIEW OF CRUDE OIL MARKET (NEW SECTION)

DOS conducted its own thorough assessment of market dynamics of the crude oil market for purposes of fully understanding how those dynamics relate to the purpose and need of the proposed Project as a part of the environmental review under NEPA. This assessment relied upon expertise within DOS from staff with extensive knowledge of international energy markets, on consultations with other federal agencies, in particular the Department of Energy, and on consideration of relevant information from the many independent sources as described below. The sources relied upon included in particular information presented in reports published by government agencies such as the Energy Information Administration (EIA), the International Energy Agency (IEA), and the Alberta Energy Resource Conservation Board (ERCB). The assessment was also informed by a recent report contracted by the Department of Energy Office of Policy & International Affairs and conducted by EnSys Energy and Systems, Inc (EnSys 2010) that evaluated different North American crude oil transport scenarios through 2030 the potential impacts of those different transport scenarios (in particular the presence or absence of the proposed Project) on U.S. refining and petroleum imports, on production and disposition of WCSB oil-sands crude, and on international crude oil markets. Because the EnSys report informs many aspects of the EIS, it is described more fully here.

The EnSys analysis examined key metrics under seven different scenarios, each representing a different combination of existing and potential pipeline transportation systems in Canada and the U.S. that could deliver WCSB crude oil to U.S. PADDs II and III and to world oil markets. Market dynamics for each pipeline combination were explored for two different projections of U.S. oil demand,[1] resulting in 14 separate scenarios.

DOE requested that EnSys address the following issues:

- What is the outlook for the U.S. refining industry's competitive position as measured by U.S. refinery throughputs, utilizations, investments, CO_2 emissions, product import dependency and oil import costs?
- How does the level and composition of crude oil imports into the U.S. change with and without the incremental WCSB crude oil transport capacity of the proposed Project?
- What are the changes in crude oils that would supply PADD III refineries with and without the transportation of incremental WCSB crude oils into PADD III?
- What are the changes in world regional demands for incremental WCSB crude oils with and without the incremental pipeline capacity to U.S. refineries?
- What are the U.S. petroleum product supply and price impacts, and also U.S. oil import cost impacts, with and without the incremental imports of WCSB crude oil to the U.S.?
- What impacts, if any, would disallowing the proposed Project have on WCSB crude oil flows into the U.S.?
- What would be the impacts of much lower U.S. product demand (consistent with the EPA low demand outlook) on U.S. refining, Canadian, and other oil imports and the implications for WCSB crude oil export capacity?

The study employed the EnSys World Oil Refining Logistics & Demand (WORLD) model to provide an integrated analysis and projection of the global petroleum industry that encompasses total liquids, captures the effects of developments, changes and interactions between regions, and projects the economics and activities of refining crude oils and products. WORLD has been used for DOE's Office of Strategic Petroleum Reserve since 1987, and has been applied in analyses for many organizations, including EIA, EPA, the American Petroleum Institute, the World Bank, the OPEC Secretariat, the International Maritime Organization, Bloomberg, and major and specialty oil and chemical companies.

Although the EnSys study is a contractor report and does not necessarily represent the views of any U.S. government agency, it was conducted in close collaboration with, and had significant input from DOE. The EnSys (2010) report is presented in Appendix A of this SDEIS. Section 1.11 presents a list of the references used in developing the need assessment for the proposed Project. Owing largely to its availability, energy density, and ease of transport, crude oil is currently the world's most important energy resource. It is traded in a global market that includes crude oils that vary in their points of delivery, densities, sulfur contents, and prices. For example, in December of 2010 the price of crude oil ranged from $73 per barrel for heavy, sour WCSB crude oil to over $88 per barrel for light, sweet crude oil such as West Texas Intermediate or Arab Light. These prices represent a balance between supply and demand in the global crude oil market. In that market, each oil field can be thought of as a potential supply source. In the past, most crude oil came from fields that produced relatively light crude oil, and while those fields are distributed throughout the world, the leading producers were in Saudi Arabia, the United

[1] EnSys (2010) included a low-demand outlook based on a February/March 2010 study by EPA which examined "more aggressive fuel economy standards and policies to address vehicle miles traveled".

States, Russia (the former USSR), and Iran. More recently, the world oil market has experienced an increase in the supply of crude oil from unconventional sources. These unconventional oil fields, primarily in Canada and Venezuela, produce a very heavy crude oil that is often referred to as bitumen.[2]

On the demand side of the market, each refinery can be thought of as a crude oil consumer. Each refinery makes decisions as to which crude oil to buy based on the characteristics of the crude (e.g., the point of delivery, density, sweetness, and price) and the refinery's unique ability to transform the crude oil into a refined petroleum product that can be profitably sold.[3]

Much effort has gone into predicting future conditions in the crude oil market. Individuals, organizations, and countries attempt to forecast supply, demand, and price based on economic trends, governmental regulations, the cost and availability of substitute forms of energy, and many other factors. While these predictions are uncertain, there is a general consensus that the volume of crude oil consumed worldwide is unlikely to decrease substantially over the next 30 years, even under policy scenarios that more aggressively address global climate change (EIA 2009c, EIA 2010a, and IEA 2010), and that the mix of crude oil consumed in the future will include an increased proportion of oil from high-cost unconventional sources and/or heavy crude oil.

For example, IEA (2010) included three policy scenarios, a Current Policies Scenario, which assumed no change in policies in place in mid-2010; a New Policies Scenario, which assumed that countries act on their announced policy commitments and plans to address climate change; and a scenario designed to stabilize greenhouse gas emissions at 450 parts per million of CO_2-equivalent, which would be consistent with an increase in global temperature of approximately 2 degrees Celsius (the 450 Scenario). There are significant differences for estimates of total global crude oil demand among the three scenarios, but in all three scenarios, the estimated total demand is greater in 2020 than in 2010. Only in the 450 Scenario is the total estimated global demand in 2035 less than in 2010. There was a significant difference in the projections of total unconventional oil production among the three scenarios, but in all three scenarios, the total estimated production from unconventional sources was projected to increase by at least 5 million bpd by 2035.

1.4.1 Supply of Heavy Crude Oil from the WCSB

The WCSB is now widely accepted as having one of the largest crude oil reserves in the world. The ERCB (2009) and CAPP (2009) estimated that Canada's oil sands contain 170 to 173 billion barrels of proven oil reserves while the Central Intelligence Agency (CIA) estimated WCSB reserves to be 175.2 billion (CIA 2010).[4] However, the mere presence of oil in a field does not mean that oil will be produced. For oil to be produced, field operators must be convinced that they can extract and deliver the oil to the marketplace in a profitable manner (i.e., the price per barrel that consumers are willing to pay is high enough for producers to make a profit). Therefore, decisions regarding unconventional crude oil production in the WCSB are affected by the price of conventional crude oil.

Given this market dynamic, CAPP (2009) reported that:

> "Over the past 12 months (June 2008 to June 2009) the industry has witnessed a dramatic change in oil prices. The benchmark West Texas Intermediate (WTI) crude oil price dropped from a

[2] For the purposes of this EIS, oil from the WCSB is referred to as heavy crude. Section 3.13.5.1 provides information on the composition of the WCSB crude oil.
[3] EIA (2009a) reported that crude oil is generally fungible, i.e., one crude oil can be substituted for another. However, many refineries are optimized to refine crude oil with specific qualities, and switching from one crude oil to another can be costly.
[4] Proven oil reserves are those that can be economically extracted given current and projected market conditions.

> peak in July 2008 of over $140 per barrel to less than $40 per barrel by year's end. CAPP's estimate of industry capital spending for oil sands development was reduced to $10 billion dollars for 2009 compared to $20 billion in 2008. The forecast for market demand growth is also lower than in the previous report, which is in line with the slower forecasted growth in supply."[5]

Most industry analysts predict that there will be growth in market demand as the global economy recovers from the recent world financial crisis. Consequently, many oil sands projects that were put on hold in 2009 were revived in 2010.

In earlier reports, CAPP (2009) projected that heavy crude production in the WCSB will increase from its 2008 level of 0.9 million bpd to between 1.4 and 1.6 million bpd by 2015 and then remain at relatively elevated levels until the end of the projection periods. These projections were largely consistent with: (1) the 2009 EIA forecast, which also projected that the unconventional oil supply from Canada will become an increasingly important source of global crude oil supply over time (EIA 2009a); and (2) projections made by ERCB (2009), the National Energy Board of Canada (NEB 2009), and Strategy West (2009). At the current and projected production levels, production from the estimated proven reserves in the WCSB could continue into the later part of the 21st century.

Three of the studies and projections referenced above were updated for 2010. CAPP (2010) projected that the WCSB will produce more than 2.1 million bpd by 2015; this is up from the 1.4 to 1.6 million bpd projected in 2009. These increased projections are largely consistent with the reference price case reported in EIA (2010a, 2010b, and 2011[6]) and Strategy West (2010) which project significant increases in WCSB crude oil production over the next 10 to 25 years. EnSys (2010) suggested that total WCSB crude oil production would reach approximately 4.4 million bpd by 2030 in almost all pipeline construction scenarios it considered. EnSys (2010) also projected oil sands production to grow to 4.2 million bpd by 2030 in the low-demand outlook for all pipeline construction scenarios except the No Expansion scenario. IEA (2010) projected that by 2035, oil sands production would increase to 4.6 million bpd under the Current Policies scenario, 4.2 million bpd in the New Policies scenario, and 3.3 million bpd under the 450 Scenario.

Historically, the majority of the WCSB crude oil has been exported to the U.S. CAPP (2010) and EIA (2010) continue to project that the vast majority of WCSB production will be exported to the U.S. Much of this will be transported to PADD II through the existing Enbridge pipeline system, including the recently constructed Alberta Clipper Pipeline and the Keystone Oil Pipeline. As described in Section 4.1.3, the proposed Enbridge Northern Gateway and the Kinder Morgan Trans Mountain pipelines, if implemented, would ship WCSB crude oil to the west coast of Canada for potential marine-based export to refineries in Asia and along the west coast of the U.S. If implemented, the proposed Project or a similar project would provide access to refineries in PADD III.

EnSys (2010) suggested that cross-border WCSB deliveries will more than double from the current 1.2 million bpd to between 2.6 and 3.6 million bpd by 2030. The volume of future U.S. imports of WCSB crude oil will be dependent on the available capacity of domestic pipelines, the level of demand for WCSB crude oil from Asian refiners, and the overall level of crude oil demand in the U.S.

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[5] Crude oil benchmarks are reference points for the various types of oil that are available in the market. The WTI is the most commonly used benchmark in the U.S.

[6] The EIA (2011) early release previewed several revisions to its reference case projections for the 2011 release, and projected that oil sands growth would reach 5.1 million bpd by 2035.

1.4.2 Demand for Heavy Crude Oil in PADD III

The U.S. petroleum industry is divided into five PADDs. Refineries within a PADD tend to have more in common with each other (e.g., pipeline infrastructure and supply streams) than they do with refineries in other PADDs.

The majority of the crude oil that would be transported by the proposed Project would be shipped to delivery points in PADD III, which has 58 refineries. These refineries represent a total refining capacity of approximately 8.4 million bpd, and for the past 20 years have run at between 80 and 100 percent of maximum throughput (EIA 2010b). PADD III refineries provide significant volumes of refined petroleum product to both the U.S. East Coast and Midwest via pipeline. For example in 2008, approximately 50 percent of the gasoline consumed on the East Coast and 18 percent of the gasoline consumed in the Midwest was supplied by PADD III refineries.

The PADD III Gulf Coast refineries have the capacity to refine over 5 million bpd of heavy crude oil (EnSys 2010). In 2009, PADD III imported approximately 2.9 million bpd of heavy crude oil (EnSys 2010). Typically, heavy crude oils sell at a discount as compared to light, sweet crude oils, and refiners that can process heavy crude oils can take advantage of that price differential. Once refiners have made the capital investments in equipment and processes to refine heavy crude oil or to increase the capacity of heavy crude oil refining, they cannot easily move back to refining a lighter crude oil slate. PADD III has a particularly high heavy crude oil processing capacity in part because of the large supplies of heavy crude oil in Mexico and Venezuela. Mexico and Venezuela, through their state-controlled oil companies, encouraged expansion of the heavy oil refining capacity through joint-venture investments in Gulf Coast refineries to create a more profitable market for their heavy crude oil resources.

There are ongoing or completed major refinery upgrades at several PADD III refineries that would have direct pipeline access to oil transported through the proposed Project (i.e., Motiva, Port Arthur; Valero, Texas City; and Total, Port Arthur) and at several PADD III refineries without direct pipeline access (Borger, Texas; Artesia, New Mexico; and Garyville, Louisiana). There are also continuing plans for upgrades in Port Arthur and revived plans in St. Charles and Tuscaloosa, Alabama, and smaller-scale upgrades designed to increase heavy crude oil refining capacity in PADD III. In PADD II, expansions and upgrades have been proposed or implemented in Oklahoma (Sinclair), Illinois (WRB Refining and ConocoPhillips Refinery), Michigan (Marathon), and Indiana (Whiting). There is no indication that the availability of oil transported via the proposed Project would directly result in specific expansions of existing refineries and development of new refineries (none have been built in the U.S. in 30 years). Recently implemented refinery expansions and upgrades in PADDs II and III were primarily focused on increasing the capacity to refine heavy crude oil. This diversification strategy could put downward pressure on PADD III crude oil prices, provided that sufficient transportation capacity is available for heavy crude oil.

In 2009, PADD III refineries imported approximately 5.1 million bpd of crude oil from more than 40 countries, and the top four suppliers were Mexico (21 percent), Venezuela (17 percent), Saudi Arabia (12 percent), and Nigeria (11 percent) (EIA 2010b). Of this amount, approximately 2.9 million bpd was heavy crude oil (EnSys 2010). In addition, PADD III refinery runs are projected to grow by at least 500,000 bpd by 2020 (Purvin & Gertz 2009, EnSys 2010). However, as noted by EnSys (2010), crude oil imports from Mexico and Venezuela, which flow predominantly into Gulf Coast refineries, have been in steady decline and are projected to continue to drop over the next several years, from 2.9 million bpd in 2004 to about 0.8 million bpd by 2020. Although the supply of crude oil from Saudi Arabia to the U.S. appears to be fairly stable, the remaining major PADD III suppliers face declining or uncertain production horizons as summarized below.

- Capital expenditures by Mexico's national oil company have been insufficient to offset natural declines in oil field output. As a result, the production of heavy crude from Mexico has been falling and there has been a 250,000-bpd decrease in production of Mexican heavy crude since 2006. In particular, production from the offshore Cantarell field (which produces most of the Maya heavy crude supplied to the U.S.) is falling rapidly (Hook et al 2009, IEA 2008, and EnSys 2010). In addition, expansion of the Minatitlan refinery is expected to be completed in early 2011 and the expanded refinery would process at least 110,000 bpd of Mexican crude oil (Reuters 2011), which could further reduce the volume exported to the U.S.
- Most of Venezuela's oil production is heavy crude, and over half of the production has been exported to the U.S. (Purvin & Gertz 2009). However, Venezuela is increasingly diversifying its oil customers to lessen its dependence on the U.S. Exports to the U.S. as a portion of Venezuela's total output have therefore decreased (Alvarez and Hanson 2009), and EnSys (2010) predicts that this trend will continue.
- Nigeria is Africa's largest oil producer. However, "since December 2005, Nigeria has experienced increased pipeline vandalism, kidnappings and militant takeovers of oil facilities in the Niger Delta…The instability in the Niger Delta has caused significant amounts of shut-in production and several companies declaring *force majeure* on oil shipments. EIA estimates Nigeria's effective oil production capacity to be around 2.7 million barrels per day (bbl/d) but as a result of attacks on oil infrastructure, 2008 monthly oil production ranged between 1.8 million bbl/d and 2.1 million bbl/d. Additional supply disruptions for the year were the result of worker strikes carried out by the Petroleum and Natural Gas Senior Staff Association of Nigeria (PENGASSAN) that shut-in 800,000 bbl/d of ExxonMobil's production for about 10 days in late April/early May" (EIA 2009e).
- Angola, Algeria, and Iraq, which were among the top 15 suppliers of crude oil to the U.S. in 2009 (EIA 2010b), have each experienced armed conflict or significant political unrest within the last decade.

In all domestic pipeline scenarios considered by EnSys (2010), increased U.S. imports of Canadian crude oil would reduce U.S. imports of foreign oil from sources outside of North America. Reductions in U.S. oil demand would result in reductions of oil imports from non-Canadian foreign sources, with no material reduction in imports of WCSB crude oil (EnSys 2010). Additionally, the firm, long-term commitment of shippers to transport 380,000 bpd of WCSB crude oil to PADD III destinations through the proposed Project indicates a market preference for WCSB heavy crude oil.

1.4.3 Transport of Crude Oil from the WCSB to PADDs II and III

Prior to 2010, two major crude oil pipelines transported crude oil from the WCSB directly to U.S. markets: the Enbridge Pipeline System and the Kinder Morgan Express Pipeline. Combined, those pipeline systems have a total capacity of about 2.1 million bpd. Of that total capacity, approximately 63 percent is heavy crude, and in 2008 both pipelines operated at or around 100 percent capacities (CAPP 2009). Two new pipeline systems were recently constructed and began transporting crude oil from the WCSB to areas in the U.S. outside of PADD III: the Keystone Oil Pipeline Project (including the Cushing Extension) and the Enbridge Alberta Clipper Pipeline. CAPP (2009) and Smith (2009) reported that, with those pipelines, the transport capacity of crude oil from Canada to the U.S. is sufficient to provide the needs of all areas outside of PADD III through 2019. EnSys (2010) projected that excess cross border capacity for areas of the U.S. outside of PADD III would exist until about 2019 to 2030. However, the capacity to transport WCSB crude oil to PADD III is currently limited. There is only one pipeline that provides PADD III refineries access to WCSB crude, the ExxonMobil Pegasus Pipeline. This pipeline has a maximum capacity of only 96,000 bpd (CAPP 2009). Thus, limited pipeline capacity continues to

constrain the supply of WCSB crude oil to PADD III (CAPP 2009 and 2010, Purvin & Gertz 2009), and PADD III represents the largest refining capacity, both overall and for heavy crude, in the U.S. Limited transport capacity to PADD III was also identified by EnSys (2010):

> "a market opportunity exists short term (2010 – 2015) as well as longer term for pipeline capacity to deliver heavy WCSB crudes to U.S. Gulf Coast refiners; this to fill a gap being created by declining supply from traditional heavy crude suppliers, notably Mexico and Venezuela, a gap it is projected would otherwise be filled by increases in other foreign supplies, notably from the Middle East."

The conclusions of CAPP (2009 and 2010), Purvin & Gertz (2009), and EnSys (2010) are consistent with observed marketplace behavior. In September 2008, when shippers were given an opportunity to enter into contractual commitments for capacity on the proposed Project, several firms executed binding contracts with Keystone for a total of 380,000 bpd of WCSB crude to be transported to PADD III for an average of 18 years. In addition, Valero, a major refinery operator in the Houston area, stated that it expects to be one of the largest recipients of heavy crude oil from the proposed Project pending regulatory approval (Valero 2008), and Canadian Natural Resources Limited (CNRL) has agreed to supply 100,000 bpd of heavy crude oil to an unnamed U.S. Gulf Coast refiner (CNRL 2008).

1.5 AGENCY PARTICIPATION

This was Section 1.3 in the draft EIS. There have been no substantive changes to this section and therefore it is not included in the SDEIS. The draft EIS subsection can be downloaded at www.keystonepipeline-xl.state.gov.

1.6 INDIAN TRIBE CONSULTATION

This was Section 1.4 in the draft EIS. There have been no substantive changes to this section and therefore it is not included in the SDEIS. The draft EIS subsection can be downloaded at www.keystonepipeline-xl.state.gov.

1.7 SHPO CONSULTATION

This was Section 1.5 in the draft EIS. There have been no substantive changes to this section and therefore it is not included in the SDEIS. The draft EIS subsection can be downloaded at www.keystonepipeline-xl.state.gov.

1.8 ENVIRONMENTAL REVIEW OF THE CANADIAN PORTION OF THE KEYSTONE XL PROJECT

This was Section 1.6 in the draft EIS. There have been no substantive changes to this section and therefore it is not included in the SDEIS. The draft EIS subsection can be downloaded at www.keystonepipeline-xl.state.gov.

1.9 PREPARATION AND REVIEW OF THE EIS

1.9.1 Scoping for the Draft EIS

This was Section 1.7.1 in the draft EIS. There have been no substantive changes to this section and therefore it is not included in the SDEIS. The draft EIS subsection can be downloaded at www.keystonepipeline-xl.state.gov.

1.9.2 Draft EIS Review Process

On January 28, 2009, DOS issued a Notice of Intent (NOI) to prepare an EIS to address reasonably foreseeable impacts from the proposed Project and alternatives, and to conduct a parallel consultation process under Section 106 of National Historic Preservation Act (NHPA). The NOI informed the public about the proposed Project and the potential DOS action, announced plans for scoping meetings, invited public participation in the scoping process, and solicited public comments for consideration in establishing the scope and content of the EIS. The NOI was published in the Federal Register and distributed to affected landowners, federal agencies, Indian tribes, state agencies, municipalities and counties, elected officials, non-governmental organizations, the media, and other interested individuals. During the scoping period, which ended on April 15, 2009, DOS held 20 separate scoping meetings in the vicinity of the proposed Project in each of the six states traversed to provide opportunity for public comment on the scope of the EIS. DOS received verbal, written, and electronic comments during the scoping period and considered them during preparation of the EIS. In addition to the public review process, DOS conducted agency consultations to identify issues to be addressed in the EIS.

The draft EIS for the proposed Project was issued for public review on April 16, 2010. The notice of availability (NOA) for the draft EIS was published in the Federal Register on April 20, 2010 and was also sent to agencies, elected officials, media organizations, Indian tribes, private landowners, and other interested parties. The NOA stated that the comment period for the draft EIS would end on May 31, 2010. In addition, approximately 2,000 copies of printed and/or electronic copies of the draft EIS were sent to libraries, elected officials, agencies, landowners, Indian tribes, and other interested parties. Electronic versions of the draft EIS were also available for download on the DOS website.

In response to requests from several organizations, on April 30, 2010 DOS extended the public comment period on the draft EIS until June 16, 2010. During that period, DOS received additional requests to extend the review period and again extended the public comment period, this time until July 2, 2010.

DOS held 19 public comment meetings from May 3 through May 20, 2010 to solicit both verbal and written comments on the draft EIS. The meetings were held in the vicinity of the proposed route in each of the states that would be traversed. In response to requests, DOS later conducted a comment meeting in Channelview, Texas (near the eastern border of Houston) and a comment meeting in Washington, D.C. In addition to receiving written and verbal comments at the draft EIS comment meetings, DOS received comments by email, website link (e-comments), telephone, and U.S. mail.

1.9.3 Preparation and Review of the Supplemental Draft EIS

This SDEIS was prepared by revising portions of the text of the EIS in response to comments on the draft EIS and, as required, to address the information available after the EIS was issued. In addition, portions of the text of the EIS were updated using information that became available after the draft EIS was issued and portions of the text were edited to provide greater clarity.

The SDEIS was issued and circulated as described for the draft EIS in Section 1.3.1. DOS invites interested parties to comment on this SDEIS during the 45-day comment period, which will begin on April 22, 2011 when EPA publishes a Notice of Availability (NOA) in the Federal Register and will end on June 6, 2011. DOS requests that comments be limited to the subject matter addressed in this SDEIS. DOS will consider all comments received during the comment period in preparation of the final EIS. Commenters do not need to resubmit their earlier comments on the draft EIS. Comments postmarked after the close of comment period will be considered to the extent practicable.

Comments on the SDEIS can be submitted to DOS using any of the following methods:

- DOS Keystone XL Project website: http://www.keystonepipeline-xl.state.gov
- Email: keystonexl@cardno.com
- Mail: Keystone XL EIS Project, P.O. Box 96503-98500, Washington, D.C. 20090-6503
- Fax: 206-269-0098

DOS will consider all comments received during the comment period in preparation of the final EIS. Comments postmarked after the close of comment period will be considered to the extent practicable. Individual names and addresses (including e-mail addresses) received as part of comment documents on this draft EIS normally are part of the public record. Anyone that wishes to have his/her name, address, or other identifying information withheld from the public record must state this request prominently at the beginning of any comment document. DOS will honor the request to the extent allowable by law. All submissions from organizations, businesses, and individuals identifying themselves as representatives or officials of organizations or businesses will be included in the public record and open to public inspection in their entirety.

1.10 PERMITS, APPROVALS, AND REGULATORY REQUIREMENTS

This was Section 1.8 in the draft EIS. There have been no substantive changes to this section and therefore it is not included in the SDEIS. The draft EIS subsection can be downloaded at www.keystonepipeline-xl.state.gov.

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2.0 PROJECT DESCRIPTION

This section of the SDEIS provides information on the proposed Project that has changed since issuance of the draft EIS. The primary changes include:

- Information on changes to the proposed Project facilities and construction of those facilities associated with withdrawal of the special permit application by Keystone and incorporation of the PHMSA recommended Special Conditions (e.g., lower maximum throughput and lower operating pressure than in the draft EIS, revised pipe wall thicknesses, change to the distance between mainline valves, and changes to construction procedures addressed by the Special Conditions);
- Relocation of the tank farm from Steele City, Nebraska to Cushing, Oklahoma;
- Revisions to the Operations and Maintenance information due to incorporation of the PHMSA Special Conditions and in response to comments on the draft EIS, including additional information on the development and review of a Project-specific Emergency Response Plan;
- Two additional connected actions, the Bakken Marketlink Project and the Cushing Marketlink Project, that were developed after the draft EIS was issued, and the potential impacts of implementation of those projects based on currently available information;
- Additional information on Future Plans and Decommissioning; and
- Incorporation of additional information on the Keystone Emergency Response Plan.

For consistency, the new information described above is presented within the relevant subsections of the EIS. In addition, the subsections that have not changed as a result of new information are also identified below. Figures for Section 2.0 of the SDEIS are presented at the end of this section.

2.1 OVERVIEW OF THE PROPOSED PROJECT

The proposed Project would have the initial capacity to deliver up to 700,000 bpd of WCSB crude oil from the proposed Canada-U.S. border crossing to delivery points in Cushing, Oklahoma, in Nederland, Texas (near Port Arthur), and in Moore Junction, Texas (east of Houston). Keystone currently has binding commitments to ship 380,000 bpd of Canadian crude oil. The proposed Project could transport up to 830,000 bpd of crude oil by adding pumping capacity if warranted by future market demand.

At the time of publication of the draft EIS, Keystone had applied to the PHMSA for consideration of a Special Permit request to operate the proposed Project at a slightly higher pressure than would be allowed using the standard design factor in the regulations. That would have resulted in a maximum crude oil throughput of approximately 900,000 bpd. On August 5, 2010, Keystone withdrew its application to PHMSA for a Special Permit, and the proposed Project would be constructed, operated, and maintained in accordance with the regulatory requirements in 49 CFR Parts 194 and 195 and the set of 57 Special Conditions developed by PHMSA presented in Appendix C of this SDEIS. As a result, the maximum throughput of the proposed Project decreased and is currently proposed to be approximately 830,000 bpd.

The proposed Project would deliver primarily WCSB crude oil (which would likely be heavy crude oil) based on current market forecasts, to three delivery points in the U.S. that in turn provide access to many other U.S. pipeline systems, terminals, and refineries. The ultimate destinations of the crude oil beyond these delivery points would not be contracted with Keystone and therefore are not considered part of the proposed Project.

The proposed Project includes three new pipeline segments in five states plus additional pumping capacity on the existing Cushing Extension of the Keystone Oil Pipeline Project. The proposed new pipeline segments are:

- The Steele City Segment (from Morgan, Montana to Steele City, Nebraska) − the southern end of this segment would connect to the northern end of the existing Cushing Extension near Steele City;
- The Gulf Coast Segment (from Cushing, Oklahoma to Nederland, Texas) − the northern end of this segment would connect to the southern end of the Cushing Extension at the Cushing tank farm; and
- The Houston Lateral (from the Gulf Coast Segment, in Liberty County, Texas to Moore Junction, in Harris County, Texas).

Approximately 1,384 linear miles of proposed new pipeline would be located in five states as listed in Table 2.1-1.

TABLE 2.1-1
Miles of New Pipe by State

Segment	State	New Pipeline Miles[a]	Mileposts (From – To)[b]
Steele City Segment	Montana	282.7	0-282.7
	South Dakota	314.2	282.7-596.8
	Nebraska	254.7	596.8-851.6
Steele City Total		**851.6**	-
Keystone Cushing Extension	Nebraska	0	N/A
	Kansas	0	N/A
	Oklahoma	0	N/A
Gulf Coast Segment	Oklahoma	155.7	0-155.7
	Texas	328.1	155.7-483.8
Gulf Coast Total		**483.8**	-
Houston Lateral	Texas	48.6	0-48.6
Project Total		**1,383.9**	-

[a] Mileages are approximate and subject to change based on final approved design and routing.
[b] Mileposting for each segment of the proposed Project starts at 0.0 at the northernmost point of each segment and increases in the direction of oil flow.

The proposed Project would include 30 new pump stations, mainline valves (MLVs) at the pump stations, 76 MLVs along the proposed pipeline (termed "intermediate" MLVs) based on current information, a tank farm at Cushing, Oklahoma that would be a delivery point, one delivery point with a surge relief system that includes two surge relief tanks at Nederland, and an oil delivery point and a surge relief system without tanks at Moore Junction.

Construction would require a 110-foot wide construction right-of-way (ROW) in most areas, pipe stockpile sites, railroad sidings, and construction camps. A 50-foot-wide ROW would be maintained along the proposed route during operation.

Keystone has Project commitments to transport approximately 600,000 bpd of crude oil, including firm contracts to transport 380,000 bpd of WCSB crude oil to existing PADD III delivery points. Keystone also has firm contracts to transport 155,000 bpd of WCSB crude oil to Cushing in its existing Keystone Oil Pipeline Project, which includes the Keystone Mainline and the Keystone Cushing Extension. If the proposed Project is approved and implemented, Keystone would transfer shipment of crude oil under those contracts to the proposed Project. In addition, the proposed Project has firm commitments to transport approximately 65,000 bpd of crude oil through the planned TransCanada Pipelines Ltd. (TransCanada) Bakken Marketlink Project and may also transport up to 150,000 bpd of crude oil through the planned TransCanada Cushing Marketlink Project (both projects are described below).

The proposed Project is planned to be in service in 2013, with the actual date dependant on receipt of all necessary permits, approvals, and authorizations.

As noted in Section 1.1, the proposed Project would primarily deliver WCSB crude oil, which would likely be heavy crude oil based on current market forecasts, to three delivery points in the U.S. that in turn provide access to many other U.S. pipeline systems and terminals. The ultimate destinations of the crude oil beyond these delivery points would not be contracted with Keystone and are not a part of the proposed Project.

There have been no changes to the remainder of Section 2.1 that are relevant to environmental concerns.

2.2 ABOVEGROUND FACILITIES

2.2.1 Pump Stations

There have been no substantive changes to this section and therefore it is not included in the SDEIS. The draft EIS subsection can be downloaded at www.keystonepipeline-xl.state.gov.

2.2.2 Mainline Valves

As proposed and reported in the draft EIS, Keystone would install 76 intermediate MLVs along the proposed route and 2 MLVs at each pump station. The intermediate MLVs would be installed within the permanent ROW. The intermediate MLVs would be sectionalizing block valves; i.e., valves that divide up the pipeline into smaller segments that can be isolated to minimize and contain the effects of a line rupture. Each MLV would be within a fenced site that would be approximately 40 feet by 50 feet. Inspection and maintenance personnel would access the MLVs through a gate that would be locked when no one is at the MLV site.

Remotely operated intermediate MLVs would be located at major river crossings, upstream of sensitive waterbodies, and at other locations required by 49 CFR 195.260 and as required by Special Conditions 32 imposed by PHMSA and agreed to by Keystone (see Section 2.3.1 and Appendix C of this SDEIS). As stipulated in Special Condition 32:

> "Keystone must design and install mainline block valves and check valves on the Keystone XL system based on the worst case discharge as calculated by 49 CFR § 194.105. Keystone shall locate valves in accordance with 49 CFR § 195.260 and by taking into consideration elevation, population, and environmentally sensitive locations, to minimize the consequences of a release from the pipeline. Mainline valves must be placed based on the analysis above or no more than twenty (20) miles apart, whichever is smaller."

As a result of this condition, there would likely be a minor increase in the number of MLVs along the proposed route. Keystone would be able to operate the valves remotely to shut down the pipeline in the event of an emergency to minimize environmental impacts if an accidental release occurs. The remotely operated valves must have remote power back-up to ensure communications are maintained during inclement weather. Mainline valves must be capable of closure at all times.

2.2.3 Pigging Facilities

There have been no substantive changes to this section and therefore it is not included in the SDEIS. The draft EIS subsection can be downloaded at www.keystonepipeline-xl.state.gov.

2.2.4 Densitometer Facilities

There have been no substantive changes to this section and therefore it is not included in the SDEIS. The draft EIS subsection can be downloaded at www.keystonepipeline-xl.state.gov.

2.2.5 Delivery Sites

Keystone would install two crude oil delivery facilities in Texas. One would be at the end of the Gulf Coast Segment in Nederland within a terminal owned and operated by Sunoco Logistics. The second would be installed at the end of the Houston Lateral in Moore Junction on a previously disturbed site. Each delivery facility would have a pig receiver on the incoming pipeline and would connect to a surge relief system and a metering system installed upstream of a manifold owned by the third party receiving crude oil transported by the proposed Project. The surge relief system at the Nederland delivery site would include two surge relief tanks, each with a capacity of approximately 10,417 barrels (435,514 gallons) (see Section 2.1.3 of the draft EIS). The delivery facilities would also include pressure regulating equipment, flow control valves, isolation valves, and a quality measurement building that would include a densitometer and a sampling system. Each delivery facility would also include a sump tank with injection pumps to receive oil from the drains of safety valves and traps. The drain system piping would connect to the main line to return captured oil to the pipeline.

The delivery facilities would operate on locally provided power.

2.2.6 Cushing Tank Farm

Keystone originally proposed to construct a tank farm in Steele City, Nebraska to manage the movement of oil through the system. However, after completing a detailed operational review of the proposed Project, Keystone determined that there would be greater operational efficiency if the tank farm were installed near Cushing, adjacent to the existing Cushing Oil Terminal, which is the largest crude oil storage facility in the U.S. and has a substantive network of connecting crude oil pipelines.

Keystone proposes to construct a tank farm on an approximately 74-acre site that is approximately 2,000 feet from the southern end of the existing Cushing Oil Terminal. The site would also include Pump Station 32. The plot plan for the Cushing tank farm is presented on Figure 2.2.6-1. As indicated on that figure, there is sufficient room on the site to house the facilities proposed for the Bakken and Cushing Marketlink projects, which are two connected actions described in Sections 2.5.3 and 2.5.4.

The Cushing tank farm would include three, 350,000-barrel aboveground storage tanks. Each tank would have a single-deck pontoon external floating roof with provisions for installation of geodesic fixed roofs. The tanks would be installed inside an impervious bermed area that would act as secondary containment. The piping in the tank farm site would be both above and below ground. The tank farm would also

include four booster pumps, one sump tank, two ultrasonic meters, pig launchers and receivers, two electrical buildings, and parking for maintenance personnel. The tanks and associated piping would be isolated electrically from the pipeline and protected by a separate cathodic protection system. The tank farm would operate on locally purchased electricity and would be fully automated for unmanned operation.

Down-lighting would be used to light the tank farm wherever possible to minimize impacts to wildlife. A security fence would be installed around the entire tank farm. Inspection and maintenance personnel would access the tank farm through a gate that would be locked when no one is at the tank farm.

2.2.7 Ancillary Facilities

2.2.7.1 Additional Temporary Workspace Areas

There have been no substantive changes to this section and therefore it is not included in the SDEIS. The draft EIS subsection can be downloaded at www.keystonepipeline-xl.state.gov.

2.2.7.2 Pipe Storage Sites, Railroad Sidings, and Contractor Yards

There have been no substantive changes to this section and therefore it is not included in the SDEIS. The draft EIS subsection can be downloaded at www.keystonepipeline-xl.state.gov.

2.2.7.3 Fuel Transfer Stations

There have been no substantive changes to this section and therefore it is not included in the SDEIS. The draft EIS subsection can be downloaded at www.keystonepipeline-xl.state.gov.

2.2.7.4 Construction Camps

Some areas within Montana and South Dakota do not have sufficient temporary housing in the vicinity of the proposed route to house all construction personnel working on spreads in those areas. In those remote areas, temporary work camps would be constructed to meet the housing needs of the construction workforce. A total of four temporary construction camps would be established: two would be in Montana, near Nashua and Baker, and two would be in South Dakota, near Union Center and Winner. Depending on the final construction spread configuration and construction schedule, additional or larger camps may be required. The number and size of camps would be determined based on the time available to complete construction and to meet Keystone's commercial commitments. All construction camps would be permitted, constructed, and operated in compliance with applicable county, state, and federal regulations. The relevant regulations that would have to be complied with and the permits required for the construction camps are presented in Table 2.2.7-3.

Design of Camps

Each construction camp site would be established on an approximately 80-acre site. Of that area, 30 acres would be used as a contractor yard, and 50 acres would be used for housing and administration facilities. The camps would be constructed using modular units and would provide the required infrastructure and systems necessary for complete food service, housing, and personal needs, including a convenience store, recreational and fitness facilities, entertainment rooms and facilities, telecommunications/media rooms, kitchen/dining facilities, laundry facilities, and security units. Each camp would also have a medical infirmary for first aid needs and to provide routine minor medical services for the workers and staff.

TABLE 2.2.7-3 Construction Camp Permits and Regulations	
Agency / State	**Permit / Discussion**
Montana	
Montana Department of Environmental Quality (MDEQ)	Public water and sewer (PWS) laws, Title 75, chapter 6, part 1, Montana Code Annotated (MCA). Rules at Administrative Rules of Montana (ARM) 17.38 101, and Department Circulars incorporated by reference. Require plan and specification review before construction of a public water or sewer system. Circulars contain design requirements. Requires water quality monitoring of water supply. Sanitation in subdivisions laws, Title 76, Chapter 4, MCA. Rules at ARM Title 17, Chapter 36. If applicable (e.g., if the site is less than 20 acres), requirements the same as PWS laws and Circulars for water supply and wastewater. Would require additional review of stormwater systems and solid waste management. (Likely not applicable unless "permanent" multiple spaces created for mobile homes or RVs. 76-4-102(16), MCA.) Water Quality Act Discharge Permits, Title 75, Chapter 5, MCA. Rules at ARM Title 17, Chapter 30. Groundwater discharge permit would be required if a wastewater drain field had a design capacity over 5,000 gallons per day (gpd). ARM 17.30.1022. Air Quality Permits, Title 17, Chapter 8, Subchapter 7. Permits would be required for sources with potential emissions exceeding 25 tons per year (tpy) unless exemptions exist and are met for temporary non-road engines.
Department of Public Health and Human Services (DPHHS)	Work Camp licensing laws, Title 50, Chapter 52, MCA. Rules at ARM Title 37, Chapter 111, Subchapter 6. Regulations regarding water, sewer, solid waste, and food service. Incorporates MDEQ PWS requirements but has additional water and sewer provisions. Administered by DPHHS, Public Health and Safety Division, Communicable Disease Control and Prevention Bureau, Food and Consumer Safety Section.
Counties	Permit required for wastewater systems, regulations adopted under Section 50-2-116(1)(k), MCA. Adopting state minimum standards promulgated by Board of Environmental Review at ARM Title 17, Chapter 36, Subchapter 9. Generally follow state laws for subdivisions, PWS, DEQ-4. Work camp permit required in some counties.
South Dakota	
South Dakota Department of Environment and Natural Resources Office of Drinking Water and Waste Water	Permit required for a Transient Non-community (TNC) PWS. There also are sampling requirements for a TNC PWS. A National Pollution Discharge Elimination System Permit would be required for waste water discharge.
South Dakota Administrative Rules	Air Quality Permit, Chapters 74:36:04-05. The diesel-fired generator engines and emergency back-up generators at each camp in South Dakota would require a minor operating permit, unless exemptions exist and are met for temporary nonroad engines.
Counties	An approach permit and a building permit may be necessary in some counties. A wide load permit is necessary for transport of modulars units to camps.

There would also be dedicated medical transport vehicles for both the camp sites and for the construction ROW.

Housing facilities of the camps would consist of modular, dormitory-like units that house roughly 28 occupants per unit. The units would have heating and air conditioning systems. The camps would be set up with the housing areas clustered together, with both shared and private wash rooms. Each camp site would provide parking for about 100 recreational vehicles. Each camp would accommodate approximately 600 people.

Potable water would be provided by drilling a well where feasible. If an adequate supply cannot be obtained from a well, water would be obtained from municipal sources or trucked to each camp. A self-contained wastewater treatment facility would be included in each camp except where it is practicable to use a licensed and permitted publically owned treatment works (POTW). Wastewater treated on site would undergo primary, secondary, and tertiary treatment consisting of solids removal, bioreactor treatment, membrane filtration, and ultraviolet exposure. Final effluent discharge would be in compliance with all applicable regulatory requirements. If a POTW is used, Keystone would either pipe or truck wastewater to the treatment facility.

Electricity for the camps would either be generated on site through diesel-fired generators, or would be provided by local utilities from an interconnection to their distribution system. Keystone would contract with a camp supplier that would provide security 24 hours per day, 7 days per week at each camp. Keystone would work with the supplier to ensure that as many local employees are hired as possible to staff the camps

Use of Camps

The camps are planned to service the needs of the proposed Project work force. As a result, the dormitories do not include facilities for families. However, workers using the recreational vehicle areas may include family members.

Most of the workers would be transported to and from the ROW each day by buses. In addition, there would be individual crews and workers that, due to the nature of their work, would be transported to and from job sites by utility trucks or by welding rigs. There would also be support workers such as mechanics, parts and supply staff, and supervisory personnel that would drive to the ROW in separate vehicles.

Based on the current construction schedule, the camps would operate in standby mode during the winter (from December through March or April). Each camp would have sufficient staff to operate and secure the camp plant and systems during that time period.

Decommissioning of Camps

Decommissioning would be accomplished in two stages. First, all infrastructure systems would be removed and either hauled away for re-use, recycled, or disposed of in accordance with regulatory requirements. Each site would then be restored and reclaimed in accordance with permit requirements and the applicable procedures described in Keystone's CMR plan (Appendix B of the draft EIS).

2.2.7.5 Access Roads

Roadway Maintenance, Repair, and Safety

There were many comments on the draft EIS concerning the maintenance and repair of road surfaces used during construction and operation of the proposed Project, as well as comments expressing concern about roadway safety. If the proposed Project receives all permits and approvals, Keystone would work with state and local road officials, the pipeline construction contractor, and a third-party road consultant to identify routes that would be used for moving materials and equipment between storage and work yards to the pipeline, valve, and pump station construction sites. When these routes are mutually agreed upon, the road consultant would document the existing conditions of roads, including a video record. When construction is completed, the same parties would review the road conditions, and Keystone would restore the roads to their preconstruction condition or better. This restoration would be paid for by Keystone.

Keystone would also perform a preliminary evaluation to determine the design-rated capacity of bridges anticipated to be used during construction and would inspect all bridges it intends to use prior to construction and confirm that the capacity of the bridges is adequate for the anticipated weights. In cases where the bridges are not adequate to handle the maximum weight, an alternate route would be used. Keystone would also inspect cattle guard crossings prior to their use. If they are determined to be inadequate to handle anticipated construction traffic, Keystone may place mats on crossings, establish an alternate crossing, enhance existing structures, or install new infrastructure with the landowner's approval. All such actions would be paid for by Keystone.

During construction, Keystone and the pipeline contractor would maintain roads used for construction in a condition that is safe for both the public and work force. Local road officials would be actively engaged in the routine assessment of road conditions.

Keystone would follow all federal, state, and local safety plans and signage as set forth in current Manuals of Uniform Traffic Control for streets and highways, or in similar documents issued by regulatory agencies along the proposed route. This would include compliance with all state and local permits pertaining to road and crossing infrastructure usage.

Keystone would require that each construction contractor submit a road use plan prior to mobilization, coordinate with the appropriate state and county representatives to develop a mutually acceptable plan, and obtain all necessary road use permits. The road use plans would identify potential scenarios that may occur during construction based on surrounding land use, known recreational activities, and seasonal influences (such as farming), and would establish measures to reduce or avoid effects to local communities. Keystone would also have inspection personnel monitor road use activities to ensure that the construction contractors comply with the road use plans and stipulations of the road.

Commenters also expressed concern that some counties in Montana stipulate that a private individual conducting maintenance of a county road becomes liable for the safety of traffic on the road. Keystone has stated that to the extent it is required to conduct maintenance of any county road in Montana, it would be done pursuant to an agreement with the applicable county, and such agreement would address potential liability, including appropriate indemnity and insurance provisions. Further, Keystone has the necessary insurance coverage to address such potential liability.

2.3 PIPELINE SYSTEM DESIGN AND CONSTRUCTION PROCEDURES

2.3.1 Pipeline Design Parameters

Many commenters expressed concerns about the safety of the proposed Project, the use of industry standards in the design of the proposed Project, and the inspection and monitoring procedures that would be conducted. The USDOT's Pipeline and Hazardous Materials Administration (PHMSA) is responsible for protecting the American public and the environment by ensuring the safe and secure movement of hazardous materials to industry and consumers by all transportation modes, including the nation's pipelines. Through PHMSA, the USDOT develops and enforces regulations for the safe, reliable, and environmentally sound operation of the nation's 2.3-million-mile pipeline transportation system and the nearly 1 million daily shipments of hazardous materials by land, sea, and air. Within PHMSA, the Office of Pipeline Safety (OPS) has the safety authority for the nation's natural gas and hazardous liquid pipelines. The proposed Project is included in the latter category.

As described below, to protect the public and environmental resources, Keystone would be required to construct, operate, maintain, inspect, and monitor the Project in compliance with the PHMSA requirements presented in 49 CFR 195 (Transportation of Hazardous Liquids by Pipeline), as well as relevant industry standards, and applicable state standards. These regulations specify pipeline material and qualification standards, minimum design requirements, and required measures to protect the pipeline from internal, external, and atmospheric corrosion. The regulations are designed to prevent crude oil pipeline accidents and to ensure adequate protection for the public.

In addition, Keystone would comply with a set of 57 Special Conditions developed by PHMSA for the proposed Project (presented in Appendix C of this SDEIS). Originally, PHMSA began development of these conditions in consideration of a special permit request from Keystone that, if granted, would have allowed Keystone to operate the Project at a maximum operating pressure higher than would be allowed using the specified design factor in 49 CFR 195.106. On August 5, 2010, Keystone withdrew its application to PHMSA for a special permit. However, DOS continued to work with PHMSA to develop Special Conditions in response to comments received about pipeline construction, operation, and maintenance. Keystone agreed to incorporate the Special Conditions into the proposed Project and would include those conditions in its manual for operations, maintenance, and emergencies that is required by 49 CFR 195.402. PHMSA has the legal authority to inspect and enforce any items contained in a pipeline operator's operations, maintenance, and emergencies manual, and would therefore have the legal authority to inspect and enforce the 57 Special Conditions if the proposed Project is approved. Incorporation of those conditions would result in a Project that would have a degree of safety over any other typically constructed domestic oil pipeline system under current code and a degree of safety along the entire length of the pipeline system similar to that which is required in High Consequence Areas (HCAs) as defined in 49 CFR 195.450.

Several commenters have recommended that the pipeline be constructed above ground. While it would be technically feasible to construct the pipeline aboveground in most areas along the proposed route, there are many disadvantages to an aboveground pipeline. In comparison to an aboveground pipeline, burying a pipeline reduces the potential for pipeline damage due to vandalism, sabotage, and the effects of other outside forces, such as vehicle collisions. Further, there has been increased concern about homeland security since the September 11, 2001 attacks, and burying the pipeline provides a higher level of security. Further, an above ground 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 more accessible to those intent on damaging the pipeline.

Nearly all petroleum pipelines in the U.S. are buried, and Keystone has also proposed to bury the proposed Project pipeline. As described above, the facilities would be designed, constructed, tested, and operated in accordance with the regulations in 49 CFR 195, the 57 Special Conditions provided to Keystone by PHMSA, and all other applicable federal and state regulations.

If the proposed Project is approved and implemented, PHMSA would maintain continual regulatory oversight over the Project, throughout construction, testing, start-up, operation, and maintenance. The PHMSA regulations presented in 49 CFR 195 Transportation of Hazardous Liquids by Pipeline specify pipeline material and qualification standards, minimum design requirements, and required measures to protect the pipeline from internal, external, and atmospheric corrosion. The regulations are designed to prevent crude oil pipeline accidents and to ensure adequate protection for the public. Section 2.3.1 presents the major pipeline design considerations of the proposed Project. In addition, the Special Conditions provide more stringent requirements for many of these design factors.

EPA submitted a comment expressing concern that the non-transportation related equipment and activities at pump stations, breakout tanks, and the tank farm may require the submission and some cases, approval, of a Facility Response Plan (FRP) as required under 40 CFR 112.20. However, it appears unlikely that the proposed Project would be required to submit an FRP under 40 CFR 112.20 for equipment and activities at the pump stations, the Cushing tank farm, or the surge relief tanks at the Nederland delivery point. Those facilities would not house any non-transportation-related equipment or activities subject to the requirement to prepare and submit an FRP. Further, 40 CFR 112.20 requires an FRP if a facility could reasonably be expected to cause substantive harm to the environment by discharging oil into or on the navigable waters or adjoining shorelines. However, if EPA makes the determination that any or all of those facilities meet the criteria for an FRP within 40 CFR 112.20, Keystone would be required to prepare and submit an FRP to EPA for review.

In addition, Keystone would prepare an Emergency Response Plan (ERP) as required by 49 CFR 194 (Response Plans for Onshore Oil Pipelines). That plan would be submitted to PHMSA for review and approval prior to initiation of operation of the proposed Project. The ERP is addressed in Sections 2.4.2.2 and 3.13.5.5.

All pipe used for the proposed Project would be required to be in compliance with the pipe design requirements of 49 CFR 195, Subpart C (Design Requirements) and PHMSA Special Conditions 1 through 4, 7, and 8. The pipeline would be constructed of high-strength X70 steel pipe that would be mill-inspected by an authorized owner's inspector and mill-tested to API 5L (American Petroleum Institute [API] 5L[7]) specification requirements. Key design parameters applicable to the proposed Project pipeline are listed in Table 2.3.1-1.

TABLE 2.3.1-1
Pipe Design Parameters and Specification

Pipe Design Parameters	Specification
Material code	API 5L-PSL2-44th Edition
Material grade thousand pounds of pressure per square inch (ksi) (yield strength)[a]	Grade X70
Maximum pump station discharge	1,300 pounds per square inch gauge (psig)
Maximum Operating Pressure (MOP)	1,300psig; 1,600 psig[a]

[7] The American Petroleum Institute (API) 5L test standard is used to determine the fracture ductility of metal line pipe. Specimens are cut from sections of pipe, soaked at a prescribed temperature, and tested within 10 seconds.

TABLE 2.3.1-1 Pipe Design Parameters and Specification	
Pipe Design Parameters	**Specification**
Minimum hydrostatic test pressure	In conformance with Special Conditions 8 and 22, the pipe must be subjected to a mill hydrostatic test pressure of 95% SMYS or greater for 10 seconds and the pre-in service hydrostatic test must be to a pressure producing a hoop stress of a minimum 100% SMYS for mainline pipe and 1.39 times MOP for pump stations for eight (8) continuous hours. The hydrostatic test results from each test must be submitted in electronic format to the applicable PHMSA Director(s) in PHMSA Central, Western and Southwest Regions after completion of each pipeline.
Joint length (feet)	Nominal 80-foot (double-joint)
Field production welding processes	Mechanized – gas metal; arc welding (GMAW); Manual-shielded metal arc welding (SMAW)
Pipeline design code	49 CFR Part 195
Outside diameter	36 inches
Line pipe wall thickness (0.72 design factor as per 49 CFR 195.106)	0.465 inch
Heavy wall thickness – High Consequence Areas (HCAs) including, high population areas, other populated areas, unusually sensitive areas, including drinking water and ecologically sensitive areas, mainline valve and pump station valve sites.	0.515 inch
Heavy wall thickness – directly downstream of pump stations at lower elevations as determined by steady state and transient hydraulic analysis. [a]	0.572 inch
Heavy wall thickness – uncased road and cased railway crossings	0.618 inch
Heavy wall thickness – uncased railway crossings, horizontal directional drillings (HDDs)[a]	0.748 inch

[a] The design of the proposed Project pipeline system is based on a maximum 1,308 pounds per square inch gauge (psig) discharge pressure at each pump station. The pump station discharge pressure would be a maximum of 1,308 psig. There would be situations where, due to elevation changes, the hydraulic head created would result in a Maximum Operating Pressure of up to and including 1,600 psig. Suction pressure at the pump stations is generally on the order of 200 psig.

Commenters have expressed concern about the quality of pipe used for the proposed Project and the countries of origin of the pipe. Keystone has stated that approximately 75 percent of the pipe for the U.S. portion of the proposed Project would be purchased from North American pipe manufacturing facilities and that regardless of the country of origin, it would purchase pipe only from qualified pipe suppliers and trading houses. Qualification includes comprehensive evaluations of manufacturing facilities, extensive technical discussions with the lead quality control and metallurgy personnel, and a clear demonstration that the mills can meet the requirements to produce and test pipe in accordance with Keystone's standards and specifications.[8] In addition, as noted above, all pipe used for the proposed Project would have to be manufactured and tested in accordance with the requirements of 49 CFR 195 and the 57 Project-specific Special Conditions developed in consultation with PHMSA and accepted by Keystone.

Keystone would review, and if appropriate, approve the pipe manufacturer's procedure specifications prior to the pipe mill initiating purchase or production of steel to ensure the material meets the API 5L

[8] Keystone would use TransCanada Pipelines pipe specifications for the proposed Project.

Line Pipe Specification and Keystone's Corporate Specifications and Project-specific requirements. Surveillance personnel would be stationed in the pipe mill through the duration of production to inspect the finished pipe and monitor compliance to the specifications throughout the manufacturing process. These personnel would monitor things such as mill test reports and other appropriate documentation, including production logs, steel quality, fabrication, welding rejection summaries, lab results, and non-conformance reports.

TransCanada's pipe manufacturing specifications also specify that any deviation in the rolling process requires testing to be recommenced from the point of deviation to ensure uniformity. Finally, additional mechanical and chemical property tests based on steel grade, plate, and/or coil would be completed based on the steel manufacturing process as well as rolling and cooling temperatures. Those tests ensure that steel properties are not variable.

To protect against corrosion, an external coating (fusion-bonded epoxy, or FBE) would be applied to the pipeline and all buried facilities, and cathodic protection (CP) would be applied to the pipeline by impressed current. These measures would be provided in compliance with 49 CFR Part 195, Subpart H (Corrosion Control) and the requirements of 14 of the PHMSA 57 Special Conditions (see Appendix C of this SDEIS). The primary impressed current CP systems would be rectifiers coupled to semi-deep vertical anode beds at each pump station, as well as rectifiers coupled to deep-well anode beds at selected intermediate mainline valve sites. The rectifiers would be variable output transformers which would convert incoming AC power to DC voltage and current to provide the necessary current density to the CP design structures. The rectifiers would have a negative cable connection to the design structure and a positive cable connection to the anode beds. The anode beds would consist of high silicon cast iron anodes backfilled with a highly conductive coke powder to allow for an expected anode minimum life of 20 years. During operation, the CP system would be monitored and remediation performed to prolong the anode bed and systems. The semi-deep anode beds would be 12-inch-diameter vertical holes spaced 15 feet apart with a bottom hole depth of approximately 45 feet. The deep-well anode bed would be a single 12-inch-diameter vertical hole with a bottom hole depth of approximately 300 feet.

Trench excavation would typically be to depths of between 7 and 8 feet, with a trench width of approximately 4 to 5 feet. In most areas, there would be a minimum of 4 feet of cover over the pipeline after backfilling. The depth of burial would be in compliance with PHMSA Special Condition 19 which states the following:

> "19) Depth of Cover: Keystone shall construct the pipeline with soil cover at a minimum depth of forty-eight (48) inches in all areas, except in consolidated rock. The minimum depth in consolidated rock areas is thirty-six (36) inches."

In addition, the depth of burial at waterbodies, ditches, drainages, and other similar features would be 60 inches, except in rocky areas where the minimum burial depth would be 36 to 48 inches. Where major waterbodies are crossed using the HDD method, the depth from the streambed to the top of the pipe would be substantively greater than 60 inches.

Special Condition 19 also requires that Keystone maintain the depth of cover after construction is completed. Specifically, the condition states the following:

> "Keystone shall maintain a depth of cover of 48 inches in cultivated areas and a depth of 42 inches in all other areas."

Some commenters recommended that Keystone install "warning tape" over the pipeline to alert excavators to the presence of the pipeline. Keystone would comply with the following stipulations of PHMSA Special Condition 19 that relates to the use of warning tape.

> "In cultivated areas where conditions prevent the maintenance of forty-eight (48) inches of cover, Keystone must employ additional protective measures to alert the public and excavators to the presence of the pipeline. The additional measures shall include:
>
> > a) Placing warning tape and additional line-of-sight pipeline markers along the affected pipeline segment,
> >
> > b) In areas where threats from chisel plowing or other activities are threats to the pipeline, the top of the pipeline must be installed and maintained at least one foot below the deepest penetration above the pipeline, not to be less than 42-inches of cover."

2.3.2 Planned Pipeline Construction Procedures

There have been no substantive changes to Sections 2.3.2.1 through 2.3.2.3 and therefore they are not included in the SDEIS. DOS notes however that the construction-related Special Conditions developed in consultation with PHMSA and accepted by Keystone (see Appendix C of the SDEIS) would apply to all construction activities. The draft EIS subsection can be downloaded at www.keystonepipeline-xl.state.gov.

2.3.2.4 Pipe Stringing, Bending, and Welding

After the pipe sections are bent, the pipeline joints would be lined up and held in position until welding. The joints would be welded together to create long "strings" that would be placed on temporary supports. All welds would be inspected using non-destructive radiographic, ultrasonic, or other methods that provide an equivalent or better level of safety as those required in 49 CFR Part 195. All aspects of welding, including reporting, would be conducted in compliance with the requirements of 49 CFR 195.228 and PHMSA Special Conditions 4, 5, 6, 12, 18, and 20 (Appendix C of this SDEIS). Welds that do not meet established specifications would be repaired or removed and replaced. Once the welds are approved, a protective epoxy coating would be applied to the welded joints to inhibit corrosion.

2.3.2.5 Installing and Backfilling

There have been no substantive changes to this section and therefore it is not included in the SDEIS. The draft EIS subsection can be downloaded at www.keystonepipeline-xl.state.gov.

2.3.2.6 Hydrostatic Testing

In addition to hydrostatic testing at the pipe mills, the pipeline would be hydrostatically tested prior to putting the pipe into service and after backfilling and all construction work that could directly affect the pipe is complete. The testing would be conducted in pipeline sections approximately 30 to 50 miles long. Hydrostatic testing would provide assurance that the system is capable of withstanding the maximum operating pressure and would be conducted in accordance with the regulatory requirements of 49 CFR Part 195, Subpart E (Pressure Testing) and the stipulations in PHMSA Special Conditions 5, 20, 22, and 23 (Appendix C of this SDEIS). The process would be conducted as follows:

- Isolate the pipe section being tested with test manifolds;
- Fill the section with water;

- Pressurize the section to a pressure that would produce a hoop stress of a minimum of 100 percent of the specified minimum yield strength for the mainline pipe and 1.39 times the maximum operating pressure for pump stations; and
- Maintain that pressure for a period of 8 hours.

2.3.2.7 Pipe Geometry Inspection, Final Tie-ins, and Commissioning

After hydrostatic testing is complete, the pipeline would be inspected using an electronic caliper (geometry) pig to check for dents or other deformations and where appropriate, pipe sections would be replaced in accordance with the requirements of 49 CFR 195 and the Special Conditions in Appendix C of this SDEIS. The final pipeline tie-ins would then be welded and inspected.

After the final tie-ins are complete and inspected, the pipeline would be cleaned and dewatered and the pipeline would be commissioned through the verification of proper installation and function of the pipeline and appurtenant systems, including control and communication equipment, based on the requirements of 49 CFR 195 and the relevant PHMSA Special Conditions.

2.3.2.8 Cleanup and Restoration

Pipeline markers would be provided for identification of the pipeline location for safety purposes in accordance with the requirements of 49 CFR 195.410 (Line Markers) and PHMSA Special Condition 40 (Appendix C of this SDEIS), including the following:

- Pipeline markers would be installed on both sides of all highways, roads, road ROWs, railroads, and waterbody crossings. Additional markers must be placed in areas where the pipeline is buried less than 48 inches;
- Pipeline markers would be made from industrial strength materials to withstand abrasion from wind and damage from cattle;
- Pipeline markers would be installed at all fences;
- Pipeline markers would be installed along the ROW to provide line-of-sight marking of the pipeline, providing it is practical to do so and consistent with the type of land use, such that it does not hinder the use of the property by the landowner. Pipeline markers would be installed at all angle points, and at intermediate points, where practical, so that from any marker, the adjacent marker in either direction would be visible;
- Consideration would be given to installing additional markers, except where they would interfere with land use (e.g., farming);
- Aerial markers showing identifying numbers would be installed at each pump station and MLV site; and
- At each MLV site and pump station, signs would be installed and maintained on the perimeter fence where the pipeline enters and exits the fenced area.

2.3.2.9 Post-Construction Reclamation Monitoring and Response

There have been no substantive changes to this section and therefore it is not included in the SDEIS. The draft EIS subsection can be downloaded at www.keystonepipeline-xl.state.gov.

2.3.3 Special Construction Procedures

There have been no substantive changes to this section and therefore it is not included in the SDEIS. The draft EIS subsection can be downloaded at www.keystonepipeline-xl.state.gov.

2.3.4 Aboveground and Ancillary Facilities Construction Procedures

There have been no substantive changes to Sections 2.3.4.1 and 2.3.4.2 and therefore they are not included in the SDEIS. The draft EIS subsection can be downloaded at www.keystonepipeline-xl.state.gov.

2.3.4.3 Mainline Valves, Pigging and Densitometer Facilities, and Delivery Sites

MLV construction would occur during mainline pipeline construction. All MLVs would be within the permanent ROW. To facilitate year-round access, the MLVs would be located as near as practicable to existing public roads. The construction sequence would consist of clearing and grading followed by trenching, valve installation, fencing, cleanup, and site restoration. If necessary, new access roads would be constructed into the fenced MLV sites. Two 10,417-barrel surge relief tanks would be installed at the end of the Gulf Coast Segment in Nederland on at a previously disturbed site with an industrial property. The area would be graded as necessary for installation of the tank foundations, and the tanks would be installed inside a bermed, impervious area that would act as secondary containment.

2.3.5 Construction Schedule, Workforce and Environmental Inspection

Based on the current permitting schedule, the proposed Project is planned to be placed into service in 2013, with the actual date dependant on dates of receipt of all necessary permits, approvals, and authorizations.

2.4 OPERATIONS AND MAINTENANCE

The proposed Project would be operated, maintained, monitored, and inspected in accordance with 49 CFR 194 and 195 and other applicable federal and state regulations. In addition to the requirements of 49 CFR 195, Keystone has agreed to incorporate 57 Special Conditions recommended by PHMSA that address Project operation, inspection, and monitoring (presented in Appendix C of this SDEIS). The operational requirements of 49 CFR 195 and the PHMSA Special Conditions related to operation of the Project (see Appendix C of this SDEIS) would be included in the Project's operations, maintenance, and emergencies manual that would be required by 49 CFR 195.402, and they would also be incorporated into Keystone's existing Operations Control Center (OCC) in Calgary, Canada.

PHMSA regulations at 49 CFR 195.450 and Special Condition 14 require that pipeline operators identify areas along the proposed pipeline corridor that would be considered High Consequence Areas (HCAs). While some of these areas need to be defined through sophisticated risk modeling, in general they are specific locales where an accidental release from a hazardous liquid pipeline could produce significant adverse consequences as described in 49 CFR 195.450. HCAs include navigable waterways, high population areas, and unusually sensitive areas. Keystone would need to identify the HCAs along the proposed route. Population changes along the route would be monitored throughout pipeline operation and any additional HCAs identified as necessary. Keystone would conduct a pipeline integrity management program in HCAs as required by 49 CFR 195.452 (Pipeline Integrity Management in High Consequence Areas).

2.4.1 Normal Operations and Routine Maintenance

There have been no substantive changes to this section and therefore it is not included in the SDEIS. The draft EIS subsection can be downloaded at www.keystonepipeline-xl.state.gov.

2.4.2 Abnormal Operations

2.4.2.1 SCADA and Leak Detection

There have been no substantive changes to this section and therefore it is not included in the SDEIS. The draft EIS subsection can be downloaded at www.keystonepipeline-xl.state.gov.

2.4.2.2 Emergency Response Procedures

A Project-specific ERP would be prepared for the system, which would be submitted to and approved by PHMSA's prior to operation. There were many comments on the ERP, including suggestions that a supplemental draft EIS be issued to include a more complete ERP and allow for public review of that plan. Those issues are addressed below along with additional information on the proposed Project ERP.

PHMSA requires that pipeline operators prepare and abide by more than one written emergency plan for responding to emergencies on their systems. First, 49 CFR 194, which is based on the Clean Water Act (CWA) of 1974 as amended by the Oil Pollution Act of 1990 (OPA 90) and direction of Executive Order 12777, requires that pipeline operators have response plans that ensure resources are available to remove, mitigate, or prevent a discharge from an oil pipeline that could cause substantive or significant harm to the environment, including a worst-case discharge. As stated in 49 CFR 194.7(a), a pipeline operator "may not handle, store, or transport oil unless the operator has submitted a response plan meeting requirements of this part," and as stated in 49 CFR 194.7(b), operators must also operate onshore pipeline facilities in accordance with the approved response plan. In addition, 49 CFR 194.107 requires that the response plan include "procedures and a list of resources for responding, to the maximum extent practicable, to a worst case discharge, and to a substantive threat of such a discharge." Those plans are reviewed by PHMSA for sufficiency prior to approval. In addition, EPA has similar authority under CWA and OPA 90 with respect to its regulation of onshore non-transportation related facilities and has promulgated its own, distinct regulations for compliance with the CWA. However, as noted in Section 2.3.1, it appears that none of the facilities or activities associated with the proposed Project would be non-transportation-related equipment or activities subject to the EPA regulatory authority.

In addition, under authority of the Pipeline Safety Act, as amended, the USDOT promulgated the Pipeline Safety Regulations presented in 49 CFR Parts 190 through 199. Among other requirements in those regulations, 49 CFR 195 requires that liquid pipeline operators prepare and follow a procedural manual for operations, maintenance, and emergencies. This written plan must follow PHMSA requirements for conducting normal operations, maintenance activities, abnormal operations, and emergencies. PHMSA inspectors review this plan for adequacy and ensure that operators are following the plan during periodic on-site inspections.

As a result, both of the proposed Project's emergency response plans would be thoroughly reviewed by PHMSA. After PHMSA review, Keystone would revise the documents as requested by PHMSA. The ERP would then be reviewed by the U.S. EPA, the U.S. Coast Guard, and states, counties, municipalities, and responders along the proposed route. Keystone would revise the ERP in response to those reviews as appropriate and as approved by PHMSA. The final ERP must be approved prior to operation and is typically prepared after most project construction is complete and specific information on the location of key project facilities and access roads are available.

While a draft ERP for the proposed Project is therefore not yet available, Keystone prepared an ERP for the existing Keystone Oil Pipeline Project that was approved by PHMSA prior to the startup of that pipeline in 2010. The ERP for the proposed Project would have the same general approach but would have many specific differences, such as the names and contact information for responders along the proposed Project route. The publically available portion of the Keystone Oil Pipeline Project ERP is included as Appendix C to the draft EIS (some of the ERP is considered confidential by PHMSA and the U.S. Department of Homeland Security). As described in Section 3.13.1.1, that document would be used as a template for the ERP for the proposed Project. Project-specific information would be inserted into the ERP as it becomes available. Once the proposed Project route is finalized, field work would commence in collecting relevant information to be incorporated into the ERP for the proposed Project, which would then be submitted to PHMSA for review and approval. In addition, response equipment would be procured and strategically positioned along the route, staff would be trained in spill response and the Incident Command System, and emergency services and public officials would be educated on all aspects of the proposed Project and what their roles would be if an accidental release were to occur. If a release were to occur, Keystone and its contractors would be responsible for recovery and cleanup.

The specific locations of Keystone's emergency responders and equipment would be determined upon conclusion of the pipeline detailed design and described in the ERP. Company emergency responders would be placed consistent with industry practice and in compliance with applicable regulations, including 49 CFR Parts 194 and 195. The response time to transfer additional resources to a potential leak site would follow an escalating tier system, with initial emergency responders capable of reaching all locations within 6 hours in the event of a spill. Typically, emergency responders would be based in closer proximity to the following areas:

- Commercially navigable waterways and other water crossings;
- Populated and urbanized areas; and
- Unusually sensitive areas, including drinking water locations, ecological, historical, and archaeological resources.

Types of emergency response equipment situated along the pipeline route would include pick-up trucks, one-ton trucks and vans; vacuum trucks; work and safety boats; containment boom; skimmers; pumps, hoses, fittings and valves; generators and extension cords; air compressors; floodlights; communications equipment including cell phones, two way radios and satellite phones; containment tanks and rubber bladders; expendable supplies including absorbent booms and pads; assorted hand and power tools including shovels, manure forks, sledge hammers, rakes, hand saws, wire cutters, cable cutters, bolt cutters, pliers and chain saws; ropes, chains, screw anchors, clevis pins and other boom connection devices; personnel protective equipment (PPE) including rubber gloves, chest and hip waders and airborne contaminant detection equipment; and wind socks, signage, air horns, flashlights, megaphones and fluorescent safety vests. Emergency response equipment would be maintained and tested in accordance with manufacturers recommendations.

Additional equipment including helicopters, fixed wing aircraft, all-terrain vehicles, snowmobiles, backhoes, dump trucks, watercraft, bull dozers, and front-end loaders could also be accessed depending upon site-specific circumstances. Other types, numbers and locations of equipment would be determined upon conclusion of the pipeline detailed design and the completion of the ERP for the proposed Project.

Several federal regulations define the notification requirements and response actions in the case of an accidental release, including the National Oil and Hazardous Substances Pollution Contingency Plan (40 CFR Part 300), the CWA, and OPA 90.

If an accidental release occurs, Keystone would implement several procedures to mitigate damage, including a line shut down. Other procedures would include immediate dispatch of a first responder to verify the release and secure the site. Simultaneously, an Incident Command System would be implemented and internal and external notifications would take place. The National Response Center (NRC) would be notified if the release meets one of the prescribed criteria. Keystone and the NRC would also notify other regional and local emergency response agencies as quickly as possible. All of this information would be included in the ERP for the proposed Project.

Many commenters expressed concern that an accidental release of heavy crude oil from the proposed Project would require unique methods to clean up the oil. As described in Section 3.13.5.3, WCSB heavy crude oil is similar to heavy crude oil currently being processed in refineries in the Houston area and elsewhere in the U.S. As a result, the behavior of WCSB heavy crude oil after an accidental release from the proposed Project would be similar to that of other heavy crude oils transported in pipelines in the U.S. and accidentally released. Therefore, the methods used to cleanup crude oil accidentally released from the proposed Project would be the same as those used elsewhere in the U.S. when heavy crude oil is accidentally released from a pipeline.

Some commenters also suggested that the EIS should provide alternatives to the ERP and evaluate those alternatives as a part of the NEPA environmental review process. Keystone's ERP would be prepared to meet the PHMSA requirements in 49 CFR 194 and would reflect actual field conditions. Due to the range of possible accidental release scenarios (including timing, size, location, season, weather conditions, and many other variables), it is not possible to assess the impact of each and every response and cleanup scenario. As a result, NEPA environmental reviews do not assess the relative effectiveness of specific procedures and ERP alternatives. Instead, ERPs are assessed prior to the startup of operations by the federal, state, and local agencies with relevant expertise and regulatory authority.

In the event of a suspected release or if a release is reported to the OCC, after verification there would be an emergency pipeline shutdown. This would involve stopping all operating pumping units at all pump stations. The on-call response designate would respond to and verify an incident. Once the OCC notifies the individual and an assessment of the probability and risk is established, field personnel could elect to dispatch other resources as soon as practical. Response efforts would first be directed to preventing or limiting any further contamination of the waterway, once any concerns with respect to health and safety of the responders have been addressed.

Many commenters expressed concern about abnormal pipeline operations that could result in an explosion. A review of PHMSA data related to pipeline accidents indicates that most "petroleum or hydrocarbon pipeline explosions" occur in pipelines that are transporting highly flammable, highly volatile hydrocarbons such as natural gas, liquid propane gas (LPG), propane, gasoline, naphtha, or similar products. Typically, any of those materials accidentally released from the pipeline form a flammable vapor cloud that can explode when it reaches a certain concentration level in air, particularly in a confined space. In rare cases diesel, gas condensate, kerosene, or similarly-refined liquid hydrocarbon ignite and burn explosively if the vapors are exposed to a fire or similar high temperature heat source, usually a fire caused by some other accident.

As noted in Section 3.13, PHMSA data for onshore oil and hazardous material pipelines indicate that only 6 of 2,706 (0.2 percent) of incidents that occurred from 1990 through 2009 were attributed to "fire/explosion as a primary cause." A search of the internet for reports of crude oil pipeline explosions suggests that (1) there are very few if any explosions in crude oil pipeline operation that were the result of a failure of the pipeline as a primary cause, and (2) the very few that have occurred are attributable to explosions in ancillary facilities or errors in operations unassociated with crude oil transportation. For example, the recent explosion and fire in the crude oil pipeline/storage tank area in Dalian, China

occurred as a result of an improper desulfurization operation; the primary cause was not the transport of crude oil in the pipeline.

The proposed Project would use pump stations that are powered by electricity; as a result, there would not be natural gas or other petroleum products at the facility that could ignite explosively. An accidental crude oil spill from the pipeline or at a pump station would likely result in some hydrocarbon vapors, but they would not be in confined spaces and therefore would be unlikely to explode.

A fire associated with a release from a crude oil pipeline is relatively rare. In the event of a fire, local emergency responders would execute the roles listed above and more specifically in the ERP, and firefighters would take actions to prevent the crude oil fire from spreading to residential areas.

2.4.2.3 Remediation

There have been no substantive changes to this section and therefore it is not included in the SDEIS. The draft EIS subsection can be downloaded at www.keystonepipeline-xl.state.gov.

2.4.3 Operations and Maintenance Conditions Imposed by PHMSA

This section has been deleted since Keystone has withdrawn its application for a special permit.

2.5 CONNECTED ACTIONS

In the draft EIS, DOS identified two actions separate from the proposed Project that are not part of the Presidential Permit application submitted by Keystone and determined that they are connected actions for the purposes of this NEPA review as defined by 40 CFR 1508.25(a)1. Those actions were the proposed construction and operation of:

- Electrical substations and power distribution lines; and
- The Big Bend to Witten 230-kilovolt (kV) transmission line (formerly the Lower Brule to Witten 230-kV transmission line).

After the draft EIS was issued, two additional potential connected actions were identified:

- The Bakken Marketlink Project; and
- The Cushing Marketlink Project.

Preliminary information on the design, construction, and operation of these two additional connected actions is described in Sections 2.5.3 and 2.5.4 of this SDEIS. Although the permit applications for these projects would be reviewed and acted on by other agencies, the potential impacts of these projects have been analyzed based on currently available information and are addressed in Section 3.15. However, only limited information was available on the design, construction, and operation of the projects. Since these projects involve non-federal lands, they will be considered by BLM in its assessment of cumulative impacts relative to the proposed Project ROW application.

No changes that are relevant to environmental concerns have been made to the information presented for those projects in the draft EIS. However, the proposed location of a 115-kV electrical power distribution line to pump station 13 of the proposed Project that would be constructed, owned, and operated by Tongue River Electric Cooperative, Inc. would cross federal lands managed by BLM in Section 32, Township 13 N, Range 53 E in Prairie County, Montana. The BLM will therefore consider this specific

power distribution line as a connected action to the proposed Project for the purposes of their NEPA analysis. Additionally, the power distribution lines that would connect with proposed Project pump stations 9 and 10 would also cross federal lands and are therefore considered connected actions to the proposed Project for the purposes of the BLM NEPA analysis. Additionally, as a result of a request for financing from Basin Electric Power Cooperative (BEPC) to the Rural Utilities Service (RUS) of the U.S. Department of Agriculture for the Big Bend to Witten 230-kV transmission line (formerly the Lower Brule to Witten 230-kV transmission line), compliance with NEPA, Section 106 of the NHPA, and other environmental review requirements will be the responsibility of the RUS as the lead federal agency.

2.5.1 Electrical Substations and Power Distribution Lines (New Title)

Information from Sections 2.5.1.1 and 2.5.2.1 of the draft EIS will be combined in this section for the final EIS. There have been no substantive changes to those sections and therefore they are not included in this SDEIS. The draft EIS subsection can be downloaded at www.keystonepipeline-xl.state.gov.

2.5.2 Big Bend to Witten 230-kV Transmission Line (New Title)

Information on the Big Bend to Witten 230-kV transmission line (formerly the Lower Brule to Witten 230-kV transmission line) presented in Sections 2.5.1.2 and 2.5.2.2 of the draft EIS will be combined in this section for the final EIS. There have been no substantive changes to those sections and therefore they are not included in this SDEIS. The draft EIS subsection can be downloaded at www.keystonepipeline-xl.state.gov.

2.5.3 Bakken Marketlink Project

Keystone Marketlink LLC (Keystone Marketlink), a wholly-owned subsidiary of TransCanada Pipelines Ltd. (TransCanada) plans to construct and operate the Bakken Marketlink Project. That project would include construction of facilities to provide crude oil transportation service from near Baker, Montana to Cushing, Oklahoma via the proposed Project and from Cushing to delivery points at Nederland and Moore Junction (east of Houston), Texas via the proposed Project. After a successful Open Season, TransCanada, on behalf of Keystone Marketlink, obtained commitments for transport of approximately 65,000 bpd of crude oil through the Bakken Marketlink Project. Baker is near many existing and proposed crude oil gathering systems, pipelines, and crude oil storage tanks, and the Bakken Marketlink project would provide direct access to PADD II and PADD III markets. The announced target in-service date for the Bakken Marketlink Project is the first quarter of 2013, with construction expected to begin in the second quarter of 2012.

The Bakken Marketlink project would consist of piping, booster pumps, meter manifolds and two tank terminals; one terminal would be near Baker, Montana, and the second would be at the proposed Cushing tank farm. The Bakken Marketlink facilities near Baker would include two, 250,000-barrel tanks that would be used to accumulate crude oil from connecting third-party pipelines and terminals and a 100,000-barrel tank that would be use for operational purposes. The larger tanks would be approximately 60 feet high and 181 feet in diameter, and the smaller tank would be approximately 60 feet high and 130 feet in diameter. The facilities in the vicinity of Baker are depicted on Figures 2.5.3-1and 2.5.3-2. As noted in Figure 2.5.3-2, the tank farm would be located adjacent to proposed Pump Station 14 and the northeastern and northwestern property boundaries would extend along the borders of the ROWs for the proposed Project and the Bridger Pipeline. The site of the tank farm and Pump Station 14 would have an area of approximately 15 acres and the offsite metering manifold would have an area of approximately 9 acres. The location of the offsite metering manifold has not been identified but would likely be in close proximity to the tank farm site. There would also be a 16-inch-diameter pipeline about 5 miles long that

would extend from an existing crude oil tank farm to the Bakken Marketlink facilities. The route of that pipeline has not been determined.

The Bakken Marketlink Project facilities at the Cushing tank farm would include two 250,000-barrel tanks that would be used for batch accumulation from the Baker facilities (see Figure 2.5.3-3). The tanks would be approximately 60 feet high and 181 feet in diameter. A plot plan for the tank farm near Cushing that includes the Bakken Marketlink tanks, the Cushing Marketlink tanks, and two portions of the proposed Project (the Cushing tank farm and Pump Station 32) is depicted in Figure 2.5.3-4. The facilities at Cushing would connect to third-party terminals that would be constructed by others.

Crude oil in the Bakken Marketlink storage tanks at the Cushing tank farm would either be pumped to the proposed Project for delivery to PADD III or delivered to other pipelines and tank farms near Cushing. The Cushing tank farm would be near many pipelines, storage facilities, and refineries since Cushing is a major crude oil marketing, refining, and pipeline hub that provides shippers with many delivery options and market access. Delivery of the crude oil to Nederland would be as described in this EIS for the proposed Project.

2.5.4 Cushing Marketlink Project

Keystone Marketlink also plans to construct and operate the Cushing Marketlink Project. This project would include construction and operation of facilities that would provide crude oil transportation service from the planned Cushing Marketlink facilities at the proposed Cushing tank farm via the proposed Project to delivery points at Nederland and Moore Junction (east of Houston), Texas. After a successful Open Season, TransCanada, on behalf of Keystone Marketlink, obtained commitments for transport of approximately 150,000 bpd of crude oil through the Cushing Marketlink Project. The Cushing tank farm would be adjacent to the Cushing Oil Terminal, which is a key pipeline transportation and crude oil storage hub with over 50 million barrels of storage capacity. As a result, the Cushing Marketlink Project would be near many pipelines and storage facilities that could ship crude oil to the Cushing Marketlink facilities. The Cushing Marketlink Project is expected to alleviate current pipeline constraints from the Cushing area and provide shippers with a new transportation option from the Cushing market to the U.S. Gulf Coast. The announced target in-service date for the Cushing Marketlink Project is the first quarter of 2013 and construction is likely to occur either during or shortly after the construction period for the proposed Cushing tank farm if the proposed Project is approved and implemented.

The Cushing Marketlink Project would include construction and operation of receipt custody transfer metering systems and two 350,000-barrel batch accumulation tanks, with one tank dedicated for light sweet crude (see Figure 2.5.3-4). The tanks would be located within the proposed Cushing tank farm property, which also would house Pump Station 32 of the proposed Project and the storage tanks for the planned Bakken Marketlink project (see Figure 2.5.3-4). The tanks would accumulate batches from connecting third-party pipelines and terminals for transportation to the U.S. Gulf Coast on the proposed Project. Delivery of the crude oil to delivery points in Texas would be as described in this EIS for the proposed Project.

2.6 FUTURE PLANS AND PROJECT DECOMMISSIONING

2.6.1 Future Plans

This section has been reorganized in the SDEIS to address future plans for the proposed Project in Section 2.6.1.1 and for other facilities in Section 2.6.1.2.

2.6.1.1 Proposed Project

As proposed, the Project would initially have a nominal transport capacity of approximately 700,000 bpd of crude oil. By increasing the capacity of the pump stations in the future, Keystone could transport up to 830,000 bpd of crude oil through the pipeline. Should Keystone decide to increase pumping capacity to 830,000 bpd at a later date, the necessary pump station upgrades would be implemented in accordance with then-applicable permits, approvals, codes, and regulations.

2.6.1.2 Other Related Facilities (New Section)

After the draft EIS was issued, plans were announced for future development of two projects that could transport crude oil to the proposed Project from producers in North Dakota and Montana and from producers in the Cushing, Oklahoma area. Those planned projects are the Bakken Marketlink Project and the Cushing Marketlink Project. As described above, those projects are considered connected actions for the purpose of the EIS.

2.6.2 Decommissioning of the Proposed Project (New Title)

Many commenters requested that the EIS provide additional information about the anticipated life of the proposed Project and a description of how the proposed Project would be decommissioned at the end of its useful life. This section of the EIS was revised in response to those requests.

2.6.2.1 Project Life

Keystone used a design life of 50 years to develop the engineering standards for the proposed Project. However, with implementation of the pipeline integrity management plan and an operations and maintenance program as described above, Keystone anticipates that the life of the proposed Project would be much longer. Many other pipeline companies have safely extended the duration of pipeline systems by replacing sections of pipe after finding anomalies and by replacing or upgrading equipment and facilities at pump stations. As a result, it is not possible to identify a specific number of years that the proposed Project may be in service.

2.6.2.2 Decommissioning

PHMSA has requirements that apply to the decommissioning of crude oil pipelines in 49 CFR Section 195.402(c)(10) and in 49 CFR 195.59 and 195.402. These regulations require that for hazardous liquid pipelines, the procedural manuals for operations, maintenance, and emergencies must include procedures for abandonment, including safe disconnection from an operating pipeline system, purging of combustibles, and sealing abandoned facilities left in place to minimize safety and environmental hazards (49 CFR 195.402). Further, these regulations require that for each abandoned onshore pipeline facility that crosses over, under, or through a commercially navigable waterway, the last operator of that facility must file a report upon abandonment of that facility. It further states that ". . . operators must submit the date of abandonment, diameter, method of abandonment, and certification that, to the best of the operator's knowledge, all of the reasonably available information requested was provided and, to the best of the operator's knowledge, the abandonment was completed in accordance with applicable laws . . . The information in the report must contain all reasonably available information related to the facility, including information in the possession of a third party. The report must contain the location, size, date, method of abandonment, and a certification that the facility has been abandoned in accordance with all applicable laws."

TransCanada (the parent company of Keystone) would adopt operating procedures to address these requirements for the proposed Project as they have for previous pipeline projects including the existing Keystone Pipeline. TransCanada typically does not abandon large diameter pipelines but generally idles or deactivates pipe as market conditions dictate. This allows a dormant pipeline to be reactivated or converted to another purpose in the future. When a pipeline or a segment of a pipeline is idled or deactivated, the pipe generally is purged of its contents, filed with an inert gas, and left in place with warning signage intact. Cathodic protection would likely be left functional as would other integrity measures such as periodic inspections under the integrity management plan.

The proposed Project pipeline would traverse approximately 44.6 miles of federal land under the management and jurisdiction of the BLM. The majority of the federal land is in the state of Montana. The portion of the proposed Project that would cross BLM-administered land would be subject to the pipeline decommissioning and abandonment requirements stipulated in the BLM right-of-way grants and permanent easement permits. These requirements are:

> "1. Boundary adjustments in Oil and Gas [user entry (lease or unit number)] shall automatically amend this right-of-way to include that portion of the facility no longer contained within the above described [user entry]. In the event an automatic amendment to this right-of way grant, the prior on-lease/unit conditions of approval of this facility will not be affected even though they would now apply to facilities outside of the lease/unit as a result of a boundary adjustment. Rental fees, if appropriate shall be recalculated based on the conditions of this grant and the regulations in effect at the time of an automatic amendment.
>
> 2. Prior to termination of the right-of-way, the holder shall contact the authorized officer to arrange a predetermination conference. This conference will be held to review the termination provisions of the grant.
>
> 3. [user entry, period of time] prior to termination of the right-of-way, the holder shall contact the authorized officer to arrange a joint inspection of the right-of-way. This inspection will be held to agree to an acceptable termination (and rehabilitation) plan. This plan shall include, but is not limited to, removal of facilities, drainage structures, or surface material, recontouring, topsoiling, or seeding. The authorized officer must approve the plan in writing prior to the holder's commencement of any termination activities."

In Texas, Section 111.025 of the Texas Natural Resources Code would apply to decommissioning of the proposed Project. The provisions of the code are:

> "(a) No common carrier may abandon any of its connections or lines except under authority of a permit granted by the commission or with written consent of the owner or duly authorized agent of the wells to which connections are made.
>
> (b) Before granting a permit to abandon any connection, the commission shall issue proper notice and hold a hearing as provided by law."

There are no state regulations applicable to pipeline decommissioning in Montana, South Dakota, Nebraska, or Oklahoma.

Decommissioning activities would have to be conducted in compliance with all applicable regulatory requirements that are in place at the time of decommissioning. Since regulations at the federal, state, and local level change over time, it would be highly speculative to project what regulatory framework would

apply to Project decommissioning at the end of the useful life of the proposed Project more than 50 years in the future.

Prior to decommissioning the Project, Keystone would identify the decommissioning procedures it would use along each portion of the route, identify the regulations it would be required to comply with, and submit applications for the appropriate environmental permits. At that point, Keystone and the issuing agencies would address the environmental impacts of implementation of the decommissioning procedures and identify the mitigation measures required to avoid or minimize impacts.

It is likely that after decommissioning there would be fewer land use restrictions than during operation of the proposed Project since either the ROW would no longer have strict encroachment limitations for protection of the purged pipeline, or the pipeline may have been removed and there would no longer be limitations of use of the former ROW.

As noted above, PHMSA regulations require that hazardous liquids pipelines be purged of combustibles prior to decommissioning. Therefore the potential for the release of contaminants from the decommissioned pipeline would be negligible.

[FIGURE PLACEHOLDER]

2.2.6-1 Cushing Tank Farm Proposed Plot Plan

2.5.3-1 Planned Bakken Marketlink Facilities near Baker, Montana

2.5.3-2 Plot Plan for Planned Bakken Marketlink Facilities near Baker, Montana

2.5.3-3 Planned Bakken Marketlink Facilities at Proposed Cushing Tank Farm

2.5.3-4 Cushing Tank Farm Proposed Plot Plan

3.0 ENVIRONMENTAL ANALYSIS

This section provides supplemental information on environmental concerns based on the changes to the proposed Project described in Section 2.0 of this SDEIS, information that was developed in response to comments on the draft EIS, and expanded explanations of existing conditions and/or impact analyses to provide clarification for reviewers of the EIS. For consistency with the organization of the draft EIS, the numbering system within each of the resource sections presented below is the same as the numbering system of the draft the EIS.

The information in the draft EIS satisfactorily addresses the issues that are not included in this SDEIS, and the draft EIS is included by reference in this SDEIS in compliance with CEQ NEPA guidelines. Within each relevant resource section, only the issues associated with the supplemental information are addressed and therefore all of the subsections within each resource section are not included: this section of the SDEIS does not address Sections 3.1 (Geology), 3.4 (Wetlands), 3.5 (Vegetation), 3.6 (Wildlife), 3.7 (Fisheries), 3.8 (Threatened and Endangered Species), 3.9 (Land Use), and 3.11 (Cultural Resources). This SDEIS includes an additional section that addresses the potential impacts of the two connected actions that were announced after the draft EIS was issued (Section 3.15, Potential Impacts of the Bakken and Cushing Marketlink Projects). Figures for this portion of the SDEIS are presented at the end of each resource section.

3.1 GEOLOGY

There have been no changes to the environmental assessment presented in this section, including the assessment of the electrical distribution lines and substations and the Big Bend to Witten 230-kV transmission line (formerly the Lower Brule to Witten 230-kV transmission line). Potential impacts associated with the Bakken Marketlink Project and the Cushing Marketlink Project are addressed in Section 3.15 of this SDEIS. The draft EIS subsection can be downloaded at www.keystonepipeline-xl.state.gov.

3.2 SOILS AND SEDIMENTS

Supplemental information on the Sand Hills topographic region of Nebraska is provided in this resource section to address concerns expressed in comments on the draft EIS and to expand the information on existing conditions as a part of understanding the potential impacts of construction and normal operation as well as unintentional releases of crude oil during operation of the proposed Project as addressed in Sections 3.13 and 4.3.

3.2.1 Sand Hills Topographic Region Existing Conditions

In northern and central Nebraska the proposed pipeline route enters portions of the Sand Hills topographic region from MP 595 to MP 707 (Figure 3.2.1-1) in Keya Paha, Rock, Holt, Garfield, Wheeler, Greeley, and Merrick counties. This region consists of a prairie landscape that supports livestock grazing, wildlife habitat, and recreation. Soils in the Sand Hills topographic region consist of aeolian well sorted sands, sandy alluvium, and lesser amounts of loess and glacial outwash. The soils are generally very deep, excessively drained to somewhat poorly drained. Depressions and drainage areas are present. Wind-blown rolling-to-hilly sand dunes are common and are stabilized by vegetation. Where vegetation has been removed, severe wind erosion is common and is often referred to as a “blowout.” In the Sand Hills topographic region, a higher percentage (55 percent) of highly erodible soils is designated as erodible by wind due to the nature of the sandy soils in this region of the proposed Project. In the eastern portion of the Sand Hills topographic region, non dune derived soils originate from glacial loess and drift deposits

(Sullivan 1994). In the southern portion of the Sand Hills topographic region (Garfield, Wheeler, and Greeley counties), approximately 24 miles of Valentine soils are present that consist of very deep, dry, rapidly permeable dune deposits; these soils contain severe wind erosion hazards. The sandy soils typical of the Sand Hills topographic region have a high infiltration rate and high permeability; however, the fine-grained loess deposits further to the east can be as thick as 200 feet and can locally restrict water flow where fractures are absent (Stanton and Qi 2007, Johnson 1960).

Many comments on the draft EIS expressed concerns related to construction in the Sand Hills topographic region. The Sand Hills topographic region contains soils that are especially sensitive to wind erosion. To address concerns related to potential erosion in the Sand Hills, specific construction, reclamation, and post-construction procedures have been developed, as described in the proposed Project CMR plan (Appendix B of the draft EIS), and in two specific Sand Hills construction documents. One of those documents (*Pipeline Construction in Sand Hills Native Rangelands*) is presented in Appendix H of the draft EIS, and the second (*Sand Hills Construction/Reclamation Unit,* a site-specific reclamation plan that itemizes construction, erosion control, and revegetation procedures in the Sand Hills region) is presented in Appendix D of this SDEIS. DOS recognizes that these native rangelands create unique challenges for restoration and reclamation. DOS has confirmed that Keystone consulted with regional experts from the University of Nebraska, University of South Dakota, the Natural Resources Conservation Service (NRCS), and the Nebraska state road department in the development of construction and reclamation plans for the Sand Hills region. The goal of the Sand Hills region reclamation plan that resulted from these consultations is to protect the integrity of this sensitive area through: maintaining soil structure and stability to the greatest extent practicable; stabilizing slopes to prevent erosion; restoring native grass species; maintaining wildlife habitat and livestock grazing production; and meeting the specifications for Sand Hills construction, operation and maintenance contained in the proposed Project CMR plan (Appendix B of the draft EIS), contract documents and details, and all applicable permits and easement descriptions.

To reduce potential impacts related to severe wind or water erosion, the following Best Management Practices (BMPs) have either been incorporated during proposed Project design or would be incorporated during construction in the Sand Hills topographic region if the proposed Project is implemented:

- The location of the proposed ROW has been sited to avoid ridgetops and existing wind blowout areas to the extent practicable;
- Specific training would be provided for construction crews prior to working in the Sand Hills region;
- Minor re-routes would be incorporated if necessary to relocate the ROW to areas with decreased wind or water erosion potential, while avoiding wetlands wherever possible;
- Grading and side-slope cuts would be minimized to the extent practicable;
- Tracked equipment and/or low ground pressure equipment would be utilized to the extent practicable during construction;
- Access to construction areas would be limited through an Access Control Plan while work is being conducted in the Sand Hills region. The plan would detail specific timing to conduct construction activities, methods to reduce traffic volume, restrictions on equipment and vehicles allowed to enter the work area, and procedures to identify and reduce any site specific issues that develop during construction;
- Disturbance of soils and native vegetation would be avoided to the extent practicable;
- Topsoil, if present, would be segregated from subsoil, consistent with proposed Project BMPs;

- Root crowns and root structures would be left in place to the maximum extent practicable;
- Following pipeline installation, revegetation of the ROW would be completed using native seed mixes adapted to the Sand Hills region;
- Straw or native prairie hay would be crimped into the exposed soil to prevent wind erosion. Annual cover crops could also be used for vegetative cover;
- Straw wattles would be used where appropriate to provide erosion control in place of earthen slope breakers;
- Photodegradable matting would be used to protect steep slopes or other areas that are prone to high wind exposure such as ridgetops or north and west facing slopes. Biodegradable pins would be used to hold the matting in place;
- If necessary, fencing would be incorporated to keep livestock from grazing on vegetation within the ROW to hasten vegetation re-establishment;
- During pipeline installation into the pipeline ditch, the maximum length of open-ditch would be limited to ten miles. Trench backfilling, final cleanup, erosion control, and revegetation must occur on a schedule that prevents the length of open-ditch from exceeding this limit; and
- Since revegetation with native species typically requires several growing seasons, the ROW through the Sand Hills topographic region would be monitored for several years to ensure that reclamation and revegetation efforts are successful. Any areas where reclamation and revegetation efforts are initially unsuccessful would be reevaluated and restored (see Appendix D of this SDEIS and Appendix H of the draft EIS).

3.2.2 Potential Impacts of Construction to the Sand Hills Topographic Region

To address concerns related to potential erosion in the Sand Hills, specific construction, reclamation, and post-construction procedures have been developed, as described in the proposed Project CMR plan (Appendix B of the draft EIS) and in two specific Sand Hills construction documents presented in Appendix H of the draft EIS and in Appendix D of this SDEIS as described above. The proposed Project ROW through the Sand Hills would be monitored for several years to ensure that reclamation and revegetation efforts are successful. Any areas where reclamation and revegetation efforts are initially unsuccessful would be reevaluated and restored.

3.2.3 Connected Actions

There have been no changes to the environmental assessment for electrical distribution lines and substations or the Big Bend to Witten 230-kV transmission line (formerly the Lower Brule to Witten 230-kV transmission line). Potential impacts associated with the Bakken Marketlink Project and the Cushing Marketlink Project are addressed in Section 3.15 of this SDEIS.

3.2.4 References

Stanton, J. and S. L. Qi. 2007. Ground Water Quality of the Northern High Plains Aquifer, 1997, 2002-2004. USGS Scientific Investigations Report SIR 2006-5138.

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[FIGURE PLACEHOLDER]

3.2.1-1 Sand Hills Topographic Region

3.3 WATER RESOURCES

Supplemental information on the existing groundwater conditions along the proposed route is provided in this resource section as an aid to understanding the potential groundwater impacts due to an accidental release of crude oil during operation of the proposed Project as discussed in Sections 3.13 and 4.3. As noted below, the inclusion of this expanded information in the analysis did not affect results of the assessment of the potential impacts of construction and normal operation of the proposed Project on groundwater. The best available information consists of records from 1955 to 2010. Some of the older data may not reflect existing conditions at some of the locations included in the analysis.

3.3.1 Environmental Setting

3.3.1.1 Groundwater

Water Quality

Major aquifers and wells in the vicinity of the proposed Project route are described in the following sections by state. Available water quality information for the aquifers described in each state is presented in Table 3.3.1-1. Available studies and reports indicate that, in general, water within these aquifers exhibits high total dissolved solids (TDS) but in general is not contaminated with other toxic ions. Most often, high levels of TDS are caused by the presence of potassium, chlorides and sodium.

TABLE 3.3.1-1
Groundwater Quality of Select Subsurface Aquifers

Aquifer	State	County	Total Dissolved Solids (mg/liter)	Other Water Quality Information
Judith River Formation[a]	MT	Phillips, Valley	500-10,000	Sodium chloride rich in Valley County
Missouri River Alluvium[b]	MT	Valley	800-2,700	NA
Hells Creek/Fox Hills[c]	MT	McCone	500-1,800	Sodium bicarbonate rich
Fox Hills[c]	MT	Dawson, Prairie, Fallon	500-2,500	Sodium bicarbonate rich
Fort Union[c]	MT	McCone, Dawson, Prairie, Fallon	500-5,000	Sodium bicarbonate rich
Yellowstone R. Alluvium[d]	MT	Dawson, Prairie, Fallon	1,000-1,500	Calcium bicarbonate rich
Hells Creek/Fox Hills[e]	SD	Harding, Perkins, Meade	1,000-3,000	Sodium bicarbonate rich
Northern High Plains Aquifer (NHPAQ)/Ogallala Formation[f]	SD	Tripp	<500	Sodium bicarbonate rich
Pleistocene River Terrace[g]	SD	Tripp	30-4,000	NA
White River Alluvium[h]	SD	Tripp	287-688	Sodium bicarbonate rich
NHPAQ/Ogallala Formation[i]	NE	Keya Paha	100-250	NA
NHPAQ/Sand Hills Unit[j]	NE	Rock-Greeley	<500	NA
NHPAQ/Ogallala Formation[j]	NE	Greeley-Nance	<500	NA

TABLE 3.3.1-1 Groundwater Quality of Select Subsurface Aquifers				
Aquifer	**State**	**County**	**Total Dissolved Solids (mg/liter)**	**Other Water Quality Information**
NHPAQ/Platte River Unit[j]	NE	Merrick	<500	NA
NHPAQ/Eastern Nebraska Unit[j]	NE	Merrick-Jefferson	<500	NA
North Canadian River Alluvium and Terrace[k]	OK	Seminole	<500	Calcium bicarbonate rich
Red River Alluvium[k]	OK	Bryan	1,000-2,000	
Central Oklahoma[l]	OK	Lincoln	<500 (in upper 200 ft)	Calcium magnesium bicarbonate
Ada-Vamoosa[k]	OK	Osage-Pontotoc	<500	Sodium chloride; Sulfate
Arbuckle-Simpson[k]	OK	Coal-Pontotac	<500	Calcium bicarbonate rich
Trinity-Antlers[k]	OK/TX	Bryan, Atoka, Fannin	300-1,500	NA
Texas Coastal Uplands[m]	TX	Hopkins-Angelina	500-1,000	NA

Data obtained from the following sources: [a] Lobmeyer 1985, [b] Swenson and Drum 1955, [c] Smith et al. 2000, [d] La Rocque 1966, [e] Whitehead 1996, [f] Rich 2005, [g] Hammond 1994, [h] Cripe and Barari 1978, [i] Newport and Krieger 1959, [j] Stanton and Qi 2007, [k] Ryder 1996, [l] Carr and Marcher 1977, [m] Ryder and Ardis 2002.

NA = not applicable.

Aquifers and Depth to Groundwater

Initial information on depth to groundwater along the proposed Project corridor was provided by Keystone. Where readily accessible data on depth to groundwater was available (Montana, South Dakota, and Nebraska), water bearing zones less than 50 feet below ground surface (bgs) were identified by examining available well data. These data included static water level, screened interval, and driller well logs within 100 feet of the centerline. In Oklahoma, it was assumed that groundwater in alluvial floodplains was present at the surface. In Texas, it was assumed that groundwater across the alluvial floodplains was present throughout the floodplain at depths less than 50 feet bgs. Based on these data limitations, locations (by milepost) along the proposed Project corridor where estimated depth to groundwater is less than 50 feet are presented in Table 3.3.1-2.

TABLE 3.3.1-2 Water-Bearing Zones Less Than 50 Feet Below Ground Surface Beneath the Proposed ROW for the Project			
State/County	**Approximate Milepost or Range**	**Approximate Depth to Groundwater (feet bgs)[a]**	**Formation/Aquifer**
Steele City Segment			
Montana			
Phillips	2	8	Cretaceous Bearpaw Shale
Phillips	6	0	Cretaceous Bearpaw Shale
Phillips /Valley	25-26	<50	Frenchman Creek alluvium
Valley	27	0-45	Late-Cretaceous Judith River Formation
Valley	38-41	0-9	Rock Creek glacial/allluvial sediments
Valley	47	6	Late-Cretaceous Judith River Formation
Valley	55-57	40-43	Late-Cretaceous Bearpaw Shale and Buggy Creek alluvium
Valley	66-72	7-63	Cherry Creek glacial/alluvial sediments
Valley	77-85	10-40	Porcupine Creek and Milk River alluvium
Valley	88	7-22	Milk River/Missouri River alluvial sediments
McCone	94	15	Late-Cretaceous Fox Hills Formation
McCone	99	26	Late-Cretaceous Hell Creek Formation
McCone	109	0	Late-Cretaceous Hell Creek Formation
McCone	119	20-30	Fort Union sands and Flying V Creek alluvium
McCone	122-123	<50	Figure Eight Creek alluvium
McCone	133-153	10-45	Fort Union sands; Redwater River alluvium; Buffalo Springs Creek alluvium; glacial drift
Dawson	159-160	10-50	Fort Union sands
Dawson	166-180	10-45	Clear Creek alluvium
Dawson	186-195	4-38	Clear Creek alluvium; Yellowstone River alluvium
Prairie	201-205	0-15	Cabin Creek alluvium
Prairie	209-214	18-40	Alluvium of merging creeks
Fallon	227	<50	Dry Fork Creek alluvium
Fallon	231-234	0	Glacial drift/alluvium
Fallon	235-238	18-45	River alluvium of Dry Creek and its tributaries
Fallon	242-250	5-26	Sandstone Creek and Butte Creek alluvium
Fallon	257-262	0-37	Hidden Water Creek; Little Beaver Creek alluvium
Fallon	264-272	0	Mud Creek and Soda Creek alluvium
Fallon	275-279	0	North and South Coal Bank Creek alluvium
Fallon	281-282	<50	Box Elder Creek alluvium
South Dakota			
Harding	289-290	<50	Shaw Creek alluvium
Harding	291-292	<50	Little Missouri River alluvium

TABLE 3.3.1-2 Water-Bearing Zones Less Than 50 Feet Below Ground Surface Beneath the Proposed ROW for the Project			
State/County	**Approximate Milepost or Range**	**Approximate Depth to Groundwater (feet bgs)[a]**	**Formation/Aquifer**
Harding	298-301	<50	Various creeks -alluvium
Harding	304-306	<50	Jones Creek alluvium
Harding	317-319	15-40	South Fork Grand River alluvium
Harding	322-324	<50	Buffalo Creek/Clarks Fork Creek alluvium
Harding	329	<50	West Squaw Creek alluvium
Harding	339	20	Red Butte Creek alluvium
Harding/Butte	351-355	<50	North Fork Moreau River alluvium
Meade	380-387	15-45	Tertiary or alluvial
Meade	390-394	25	Tertiary or alluvial
Meade	399	18	Sulphur Creek alluvium
Meade	403-404	14-44	Spring Creek alluvium
Meade	407-408	14	Red Owl Creek alluvium
Meade	411	3	Narcelle Creek alluvium
Meade	425	5	Cheyenne River alluvium
Pennington/Haakon	432-437	<50	Alluvial
Haakon	442	12	Alluvial
Haakon	475	37	Alluvial
Haakon	478-481	14-25	Bad River alluvium
Jones	518-519	6	Alluvial
Lyman	535-536	6	White River alluvium
Tripp	539	23	NHPAQ/ Ogallala Formation
Tripp	561-564	3-9	NHPAQ/ Ogallala Formation
Tripp	570 -595	6-25	NHPAQ/ Ogallala Formation
Nebraska			
Keya Paha	597-600	<50	Keya Paha River alluvium
Keya Paha/Rock	603-616	<50	NHPAQ/ Ogallala Formation and Sandhills Unit.
Keya Paha	613-614	<50	Niobrara River alluvium
Rock /Holt/Garfield	624-675	<50	NHPAQ/ Ogallala Formation and Sandhills Unit. with flowing wells, groundwater seeps, and shallow lakes
Wheeler	692-697	<50	Cedar River alluvium
Nance	726-729	<50	South Branch Timber Creek alluvium
Nance/Merrick	737-757	<10[b]-55	Platte River floodplain alluvium
York	778-779	<50	Beaver Creek alluvium
York	788-789	<10[b]-90	West Fork Big Blue River alluvium
Fillmore/Saline	807-822	<50	South Fork Turkey Creek alluvium

TABLE 3.3.1-2 Water-Bearing Zones Less Than 50 Feet Below Ground Surface Beneath the Proposed ROW for the Project			
State/County	**Approximate Milepost or Range**	**Approximate Depth to Groundwater (feet bgs)[a]**	**Formation/Aquifer**
Jefferson	834-836	<10[b]-50	South Fork Swan Creek alluvium
Jefferson	847	<50	Tributary to Big Indian Creek alluvium
Gulf Coast Segment			
Oklahoma			
Lincoln	1-4	0	Wildhorse Creek alluvium
Lincoln/Creek	19-20	0	Euchee Creek alluvium
Creek/Okfuskee	22-25	0	Deep Fork River alluvium
Okfuskee	28-29	0	Little Hilliby Creek alluvium
Okfuskee	30-31	0	Hilliby Creek alluvium
Okfuskee	33	40	Very High Groundwater sensitivity area
Okfuskee/Seminole	38-39	47	North Canadian River - Very High Groundwater Sensitivity Area
Seminole	43-45	0	Sand Creek alluvium
Seminole	47-48	0	Little Wewoka Creek alluvium
Seminole	50-51	0	Wewoka Creek alluvium
Seminole/Hughes	58-61	0	Wewoka Creek alluvium
Hughes	66-68	0	Bird Creek -Very High Groundwater sensitivity area
Hughes	70-71	0	Little River alluvium
Hughes	74-76	0	Canadian River alluvium
Coal	87-88	0	Muddy Boggy Creek alluvium
Atoka	127-130	0	Clear Boggy Creek alluvium
Bryan	133-134	0	Long Branch alluvium
Bryan	145	0	Whitegrass Creek alluvium
Bryan	155-156	0	Red River alluvium
Texas			
Fannin	156-161	<50	Red River alluvium
Lamar	170	<50	Sanders Creek alluvium
Lamar	172	<50	Cottonwood Creek alluvium
Lamar/-Delta	187-191	<50	North Sulfur River alluvium
Delta/Hopkins	201-202	<50	South Sulfur River alluvium
Hopkins	212-213	<50	White Oak Creek alluvium
Hopkins	216-217	<50	Stouts Creek alluvium
Franklin	227-228	<50	Big Cypress Creek alluvium
Wood/Upshur	256-257	<50	Big Sandy Creek alluvium
Upshur	260-263	<50	Sabine River alluvium
Cherokee	297-301	<50	Striker Creek alluvium

TABLE 3.3.1-2 Water-Bearing Zones Less Than 50 Feet Below Ground Surface Beneath the Proposed ROW for the Project			
State/County	**Approximate Milepost or Range**	**Approximate Depth to Groundwater (feet bgs)[a]**	**Formation/Aquifer**
Rusk	308-313	<50	East Fork Angelina River alluvium
Nacogdoches/ Cherokee	330-336	<50	Angelina River floodplain alluvium
Angelina	345-346	<50	Neches River alluvium
Angelina	350-353	<50	Neches River alluvium
Angelina/Polk	360-369	<50	Neches River alluvium
Polk	374-375	<50	Bear Creek alluvium
Polk	380	<50	Jones Creek alluvium
Polk	400-406	<50	Menard Creek alluvium
Polk/Liberty	412-431	<50	Middle Pleistocene sand/silt along Trinity River
Liberty	432-446	<50	Willow Creek/Pine Island Bayou floodplain alluvium
Jefferson	448-480	<50	Late Pleistocene mud/silt in floodplains of various rivers that coalesce.

[a] bgs = below ground surface; based on available well data from Keystone 2009, except where noted for footnote b.

[b] Data from NEDNR 2010.

Note: Mileposting for each segment of the Project starts at 0.0 at the northernmost point of each segment, and increases in the direction of oil flow.

Supplemental information on groundwater occurrence and depth to groundwater by state has been evaluated (see Figures 3.3.1-1 through 3.3.1-5) to address concerns expressed in comments on the draft EIS relative to the Northern High Plains Aquifer (NHPAQ) system (including the Ogallala aquifer) and concerns relative to other aquifers along the proposed Project corridor. The supplemental analysis provides more information on the likely occurrence of potable groundwater in water wells within 1 mile of the proposed pipeline centerline using publicly available and searchable databases maintained by water resource agencies within each state that would be crossed by the proposed Project. The databases were searched for domestic, irrigation, and public water supply well data. The analysis of impacts on water supplies for human consumption also applies to water intakes for industrial and municipal use. Data accessed included well locations, well total depth, and depth to first water (if available) or static water level (see Appendix E of this SDEIS). The screened intervals for individual water wells were not readily available in these databases. Since the screened intervals are not available, it is not possible in all cases to correlate static water level to likely depth to first water. Given limitations and variations in data quality from state to state, five general categories that relate well depth and reported water levels (first water or static water level) to likely water depth were created. These categories are:

- Category A: very shallow water depth likely with reported water level less than or equal to 10 feet bgs and total well depth less than or equal to 50 feet bgs;
- Category B: shallow water depth likely with reported water level between 10 and 50 feet bgs and total well depth less than or equal to 50 feet bgs;
- Category C: water depth unclear but potentially very shallow since reported water level is less than or equal to 10 feet bgs and total well depth is greater than 50 feet bgs (reported water level

could indicate very shallow water depth if well screened in upper 50 feet or deep water depth if well screened at deeper interval under artesian conditions);

- Category D: water depth unclear but potentially shallow since reported water level is between 10 and 50 feet bgs and total well depth is greater than 50 feet bgs (reported water level could indicate shallow water depth if well screened in upper 50 feet or deep water depth if well screened at deeper interval under artesian conditions); and
- Category E: deep water depth likely with reported water level greater than 50 feet bgs and total well depth greater than 50 feet bgs.

Information on key aquifers that would be crossed by the proposed Project and additional information on likely depth to groundwater based on the above categories is presented by state in the following subsections.

Montana

Key Aquifers

The proposed pipeline route is present in the Great Plains physiographic province in Montana (Thornbury 1965). Regionally, aquifers beneath the proposed route are part of the Northern Great Plains aquifer system (Whitehead 1996). In Montana, aquifers consist of unconsolidated alluvial and/or glacial aquifers, lower Tertiary-aged aquifers, and upper Cretaceous-aged aquifers (see Figure 3.3.1-1). Groundwater resources along alternate pipeline routes considered in Montana are described in Appendix I to the draft EIS.

In northern Montana, in Phillips and Valley counties, glacial till is present up to 100 feet thick. The till is relatively impermeable and acts as a confining layer above the Cretaceous-aged Judith River Formation and Clagett Formation (Whitehead 1996). The Judith River Formation water table is present at approximately 150 to 500 feet bgs. Wells typically yield 5 to 20 gallons per minute (gpm). Additionally, the glacial till contains local permeable zones of coarse glacial outwash less than 50 feet bgs that provide irrigation water. Most groundwater use in Valley County comes from shallow alluvial aquifers along major river drainages such as the Milk River and Missouri River (Whitehead 1996).

In McCone County, the proposed route crosses the upper-Cretaceous Hells Creek/Fox Hills aquifer and the lower Tertiary Fort Union aquifer. Permeable sandstones of the Hells Creek/Fox Hills aquifer yield 5 to 20 gpm; most wells are drilled to depths of 150 to 500 feet bgs (Whitehead 1996). The lower Tertiary Fort Union aquifer consists of interbedded sandstones, mudstones, shale, and coal seams. Water-bearing zones are found in the sandstone layers. The aquifer is confined in most areas. Well yields are typically 15 to 25 gpm; most wells are drilled to depths of 50 to 300 feet bgs (Lobmeyer 1985); water depths typically range from 100 to 150 feet bgs (Swenson and Drum 1955).

Beneath the proposed route in Dawson, Prairie, and Fallon counties lies the Lower Yellowstone aquifer system which contains groundwater in the lower Tertiary Fort Union Formation. In this area, the Fort Union Formation is a shallow bedrock aquifer that is used as a groundwater resource in these three counties. The Yellowstone River contains abundant alluvial material along its banks which contain shallow aquifers that are often used for water supply. Well yields in the shallow aquifers along the Yellowstone River range from 50 to 500 gpm (LaRocque 1966). Additionally, shallow alluvial aquifers are also present at stream crossings including Clear Creek, Cracker Box/Timber Creek, Cabin Creek, Sandstone Creek, and Butte Creek.

The proposed Project pipeline route does not cross any sole-source aquifers in Montana, as designated by EPA Region 8 (EPA 2009).

Nearby Public Water Supply Wells and Private Water Wells

No public water supply (PWS) wells or source water protection areas (SWPA) are located within 1 mile of the centerline of the pipeline in Montana. A total of eight private water wells are located within approximately 100 feet of the proposed pipeline route within McCone, Dawson, Prairie, and Fallon counties.

Likely Depth to Groundwater

Estimates of the likely depth to groundwater at existing well locations within 1 mile of the proposed pipeline in Montana are provided in Figure 3.3.1-1. As depicted in Figure 3.3.1-1, the numbers of wells within 1 mile of the proposed pipeline that fall within each groundwater depth category are as follows:

- Category A (very shallow): 51
- Category B (shallow): 22
- Category C (unclear but potentially very shallow): 46
- Category D (unclear but potentially shallow): 38
- Category E (deep): 59

South Dakota

Key Aquifers

In South Dakota the proposed pipeline route is present in the Great Plains physiographic province (Thornbury 1965). In northern and north-central South Dakota, aquifers beneath the proposed route are part of the Northern Great Plains Aquifer system (Whitehead 1996). Key aquifers in South Dakota are depicted in Figure 3.3.1-2. These aquifers include the upper-Cretaceous Fox Hills and Hells Creek aquifers in Harding, Perkins, and Meade counties. The town of Bison uses groundwater from the Fox Hills aquifer for its water supply. These municipal wells are 565 to 867 feet deep and yield up to 50 gpm (Steece 1981). Shallow alluvial aquifers are also present at stream crossings including Little Missouri River, South Fork Grand River, Clarks Fork Creek, Moreau River, Sulphur Creek, Red Owl Creek, and Cheyenne River.

In Haakon, Jones, and Lyman counties major water-producing aquifers are not present. The proposed route is underlain by the upper-Cretaceous Pierre Shale which is not an aquifer. The floodplains of the Bad River and the White River contain shallow alluvial aquifers that are used for water supply.

In southern South Dakota, the proposed route is underlain by the northern portion of the NHPAQ system and contains Tertiary-aged aquifers and Pleistocene-aged river terrace aquifers (Whitehead 1996). This aquifer system is located primarily in Nebraska, but underlies portions of five states, including South Dakota. Tertiary-aged aquifers include the Ogallala Formation and the Brule and Arikaree Formation. Depth to groundwater of the Ogallala Formation is typically 10 to 70 feet bgs (Hammond 1994) with wells yielding 250 to 750 gpm.

The proposed pipeline route does not cross any sole-source aquifers in South Dakota, as designated by EPA Region 8 (EPA 2009).

Nearby Public Water Supply Wells and Private Water Wells

One PWS well (associated with the Colome SWPA) is identified within 1 mile of the centerline of the pipeline in Tripp County. This PWS wells is screened at relatively shallow depth (reportedly less than 54 feet bgs) within the Tertiary Ogallala aquifer. The proposed Project would pass through the Colome SWPA in Tripp County. No private water wells are located within approximately 100 feet of the proposed pipeline route in South Dakota.

Likely Depth to Groundwater

Estimates of the likely depth to groundwater at existing well locations within 1 mile of the proposed pipeline in South Dakota are provided in Figure 3.3.1-2. As depicted in Figure 3.3.1-2, the numbers of wells within 1 mile of the proposed pipeline that fall within each groundwater depth category are as follows:

- Category A (very shallow): 11
- Category B (shallow): 13
- Category C (unclear but potentially very shallow): 5
- Category D (unclear but potentially shallow): 40
- Category E (deep): 58

Nebraska

Key Aquifers

The proposed route in Nebraska also overlies the NHPAQ system. The NHPAQ system supplies 78 percent of the public water supply and 83 percent of irrigation water in Nebraska (Emmons and Bowman 1999). Many commenters on the DEIS requested additional information on portions of the NHPAQ system that could be impacted by the proposed Project.

In Nebraska, the NHPAQ system includes five main hydrogeologic units, including the Brule and Arikaree Formation, the Eastern Nebraska Unit, the Ogallala Formation, the Platte River Valley Unit, and the Sand Hills Unit (see Figure 3.3.1-6). These units occur over approximately 64,400 square miles in Nebraska. The proposed Project ROW would extend 247 linear miles through areas underlain by the NHPAQ system. The pipeline would immediately overlie 81 miles of the Eastern Nebraska Unit, 62 miles of the Ogallala Formation, 12 miles of the Platte River Valley Unit, and 92 miles of the Sand Hills Unit.

The type of soil that overlies the NHPAQ system generally consists of silt loam and sand, although clay loam, loam, and sandy loam are also present (Stanton and Qi 2007). In the High Plains Aquifer, which includes the NHPAQ system, hydraulic conductivity (a measurement of the rate of movement of water through a porous medium such as an aquifer or a soil) ranges from 25 to 100 feet per day (ft/d) in 68 percent of the aquifer and averages 60 ft/d (Weeks et al. 1988). In general, ground water velocity (which also takes into account the porosity and the hydraulic gradient [slope of the water table]) in the High Plains Aquifer is 1 ft/d and flows from west to east (Luckey et al. 1986).

The soils of the Sand Hills Unit of the NHPAQ system are derived primarily from aeolian dune sands and are characterized by very low organic and clay/silt fractions. According to the USGS, the hydraulic conductivity of the Northern High Plains aquifer is relatively small, particularly in the Sand Hills north of

the Platte River (Gutentag et al. 1984; Luckey et al. 1986). The aquifer material in this region is composed mainly of fine sands and silts with little hydraulic conductivity (Luckey et al. 1986). Estimates of the hydraulic conductivity of the Sand Hills Unit of the NHPAQ system are variable, with a high end estimate of 50 ft/d (Gutentag et al. 1984) and a lower range estimate of 40 ft/d to 13 ft/d (Lappala 1978). Hydraulic conductivity values for the dune sands at the surface in the Sand Hills Unit range from 16.4 ft/d to 23.0 ft/d near the ground surface (8 inches in depth) (Wang, et al, 2006). At intermediate depths within the root zone, hydraulic conductivity values range from 26.3 ft/d to 32.8 ft/d in lowland areas and 32.8 ft/d to 49.2 ft/d in higher areas. In the lower boundary of the root zone, at approximately 6.5 ft bgs, hydraulic conductivities ranged from 42.7 ft/d to 49.2 ft/d (Wang et al. 2006). These values were based on direct in-situ measurements by constant head permeameter.

In the eastern portion of the Sand Hills Unit, non dune derived soils originate from glacial loess and drift deposits (Sullivan, 1994). These fine-grained loess deposits further to the east can be as thick as 200 feet and can locally restrict water flow where fractures are absent (USGS SIR 2006-5138, Johnson 1960).

Certain areas within the Ogallala Formation of the NHPAQ system contain soils or lithologic zones that inhibit downward contaminant migration (Gurdak et al. 2009). In these areas transport of dissolved chemicals from the land surface to the water table is slower, taking decades to centuries (Gurdak et al. 2009). However even in these areas, localized preferential flow paths do exist that could enable dissolved chemicals to move at an increased rate through the unsaturated zone to the water table. These preferential flow paths are more likely to be present beneath topographic depressions, where precipitation or surface water collects. Preferential pathways with lower infiltration rates are more likely to be present in areas of fine-grained sediments or beneath flat terrain where free-standing water does not pool or collect (Gurdak et al. 2009). These areas within the Ogallala Formation of the NHPAQ system consist of geologic units that comprise unconsolidated sand, gravel, clay, and silt along with layers of calcium carbonate and siliceous cementation (Stanton and Qi 2007). According to the USGS water quality report, a zone of post-deposition cementation is present in many of these areas near the top of the Ogallala Formation, creating an erosion resistant ledge. The Ogallala Formation also contains localized ash beds. These cementation zones and ash layers would serve as localized aquitards within the Ogallala Formation and would tend to inhibit vertical migration of dissolved contaminants.

In Keya Paha County (northern Nebraska), wells yield 100 to 250 gpm (Newport and Krieger 1959). Alluvial aquifers are also present at the Keya Paha River and the Niobrara River. The Niobrara River is used as a source of irrigation and municipal water supply.

From Rock through Greeley counties, the project route is underlain by the NHPAQ system (Sand Hills Unit and Ogallala Formation). The Sand Hills Unit typically has a shallow water table less than 30 feet bgs and is therefore a potential concern (Stanton and Qi 2006). Alluvial aquifers are also present along the Elkhorn River and its tributaries and the Cedar River.

Beneath Nance, Merrick, and Hamilton counties, the project route is again underlain by the Ogallala Formation of the NHPAQ system to the Loup River. From the Loup River to the Platte River, the project route is underlain by the Platte River Valley Unit of the NHPAQ system. Additional shallow aquifers crossed by the proposed Project include the alluvial aquifer of the South Branch Timber Creek and the alluvial aquifer of the Loup River (used for irrigation and domestic water supply).

South of the Platte River, the proposed route crosses the Eastern Nebraska Unit of the NHPAQ system, used for irrigation, domestic, and municipal water supply. Hordville's public water supply comes from wells screened within this aquifer from 160 to 262 feet bgs (Keech 1962).

From York to Jefferson counties, the depth to groundwater is on average 80 feet bgs within the Eastern Nebraska Unit of the NHPAQ system (Stanton and Qi 2006). Additionally, the project route crosses alluvial aquifers along Beaver Creek, the West Fork of the Big Blue River, and the alluvial floodplain of the South Fork Turkey Creek.

While the water quality in the NHPAQ system is suitable for drinking and as irrigation water, impacts from farming operations are present in areas of shallow groundwater. In areas where crop irrigation occurs and shallow groundwater is present, elevated levels of fertilizers, pesticides, and herbicides occur, including nitrate and atrazine, indicative of impact caused by farming operations. Concentrations of these constituents are generally higher in the near-surface groundwater (Stanton and Qi 2007).

The proposed pipeline route does not cross any EPA designated sole-source aquifers in Nebraska (EPA 2009).

Nearby Public Water Supply Wells and Private Water Wells

Eight PWS wells are present within 1 mile of the centerline of the proposed route in Hamilton, York, Fillmore, Saline, and Jefferson counties. The proposed route would not however pass through any identified PWS wellhead protection areas. SWPAs within 1 mile of the proposed Project include those for the towns of Ericson, Hordville, McCool Junction, Exeter, Steele City and the Rock Creek State Park. Additional SWPAs within 1 mile of the proposed Project include those mapped in Hamilton County near Milepost (MP) 772 and York County near MP 781 and 783. A total of 29 private water wells are located within approximately 100 feet of the proposed pipeline route within Greeley, Merrick, Hamilton, York, Fillmore, and Jefferson counties.

Likely Depth to Groundwater

Estimates of the likely depth to groundwater at existing well locations within 1 mile of the proposed pipeline in Nebraska are provided in Figure 3.3.1-3. As depicted in Figure 3.3.1-3, the numbers of wells within 1 mile of the proposed pipeline that fall within each groundwater depth category are as follows:

- Category A (very shallow): 183
- Category B (shallow): 62
- Category C (unclear but potentially very shallow): 115
- Category D (unclear but potentially shallow): 205
- Category E (deep): 629

Additionally, a USGS analysis suggests that depth to groundwater in the NHPAQ system is variable and ranges from 0 to 272 feet bgs (Stanton and Qi 2007). The median depths to groundwater in the NHPAQ units that would be crossed by the proposed Project in Nebraska are:

- Ogallala Formation: 110 feet bgs
- Eastern Nebraska Unit: 79 feet bgs
- Sand Hills Unit: 20 feet bgs
- Platte River Valley Unit: 5 feet bgs

The well locations where estimated groundwater depth falls within Categories A and C can be used to estimate the distance along the proposed pipeline corridor in Nebraska where water depths less than or equal to 10 feet bgs could be encountered. These data suggest that approximately 65 miles of the proposed pipeline corridor in Nebraska could encounter groundwater at a depth below ground surface less than or equal to 10 feet (see Figure 3.3.1-3). The majority of these areas are present in the Sand Hills Unit and the Platte River Valley Unit and overlie the deeper Ogallala Formation.

Kansas

Construction planned in Kansas as part of the proposed Project comprises two new pump stations located in Clay and Butler counties along the existing Cushing Extension of the Keystone pipeline. These counties are underlain by the near surface Permian-aged Flint Hills aquifer. The Flint Hills aquifer, a source for numerous small springs, exhibits yields up to 1,000 gallons per minute and is a source for potable water supplies.

Oklahoma

Key Aquifers

The majority of water supply in eastern Oklahoma comes from shallow alluvial and terrace aquifers (Ryder 1996). Key aquifers in Oklahoma are depicted in Figure 3.3.1-4. Alluvial aquifers are located within the floodplains of major rivers and terrace aquifers are present in historical floodplain terraces. Alluvial aquifers contain a shallow unconfined water table while terrace aquifers typically contain a water table depth of 30 to 50 bgs (Ryder 1996). Major rivers and floodplains that contain these aquifers include the North Canadian River, the Canadian River, and the Red River at the state's southern border. Well yields for these aquifers are up to 1,000 gpm for the North Canadian River aquifer, up to 500 gpm for the Canadian River aquifer, and 200 to 500 gpm for the Red River aquifer (Ryder 1996). Alluvial and terrace aquifers consist of Quaternary and late tertiary deposits of sand and gravel interbedded with clay and silt. These aquifers are used for water supply in eastern Oklahoma (Ryder 1996).

Deeper bedrock aquifers include the Garber-Wellington aquifer, the Vamoosa-Ada aquifer, and the Antlers aquifer. The Garber-Wellington aquifer consists of confined and unconfined formations. Well yields range from 70 to 475 gpm (Carr and Marchur 1977) and well depths can be as shallow as 20 feet bgs but are also screened at depths up to 1,000 feet bgs. This aquifer lies adjacent to the west of the proposed route in central Oklahoma. The Vamoosa-Ada aquifer is present beneath the proposed route from Osage to Pontotoc counties and is composed of sandstone and interbedded shale. Wells typically yield 25 to 150 gpm and are used for domestic supply (Ryder 1996). The Antlers aquifer is located beneath the Red River at the state line between Oklahoma and Texas. In Atoka County, the aquifer is present in Cretaceous-aged sandstone and is unconfined; the aquifer is confined beneath Bryan County to the state border. Water is used for domestic, irrigation, commercial and public water supply (Ryder 1996).

Although the proposed pipeline route does not cross any sole-source aquifers in Oklahoma, the route would pass to the east of the Arbuckle-Simpson aquifer, a designated sole-source aquifer by EPA Region 6 (EPA 2009). From the center line of the pipeline, the eastern extent of the Arbuckle-Simpson aquifer is approximately 12 miles to the west. The Arbuckle-Simpson aquifer underlies the Arbuckle Mountains and Arbuckle Plains in south central Oklahoma and is composed of sandstone and interbedded shale (Ryder 1996). Water is present to depths up to 3,000 feet bgs and wells typically yield 100 to 500 gpm.

Nearby Public Water Supply Wells and Private Water Wells

Within 1 mile of the proposed pipeline route in Hughes, Coal, and Bryan counties, 28 PWS wells are present. The number of private water wells located within 100 feet of the proposed pipeline route in Oklahoma is unknown.

Likely Depth to Groundwater

Estimates of the likely depth to groundwater at existing well locations within 1 mile of the proposed pipeline in Oklahoma are provided in Figure 3.3.1-4. As depicted in Figure 3.3.1-4, the numbers of wells within 1 mile of the proposed pipeline that fall within each groundwater depth category are as follows:

- Category A (very shallow): 1
- Category B (shallow): 2
- Category C (unclear but potentially very shallow): 41
- Category D (unclear but potentially shallow): 60
- Category E (deep): 64

Texas

Key Aquifers

Three principal aquifers are present beneath the proposed Project route, including the Trinity aquifer located south of the Red River at the state line, the Texas Coastal Uplands aquifer system from Hopkins County to the Neches River in Angelina County, and the Texas Coastal Lowlands aquifer system from Polk to Jefferson counties (Ryder 1996). Key aquifers in Texas are depicted in Figure 3.3.1-5. These aquifer systems are composed of multiple aquifers that are described below.

The Trinity aquifer consists of Cretaceous-aged sandstone, siltsone, clay, conglomerate, shale, and limestone. Wells yield 50 to 500 gpm and wells are typically 50 to 800 feet deep (Ryder 1996). Water is used for domestic and agricultural use.

The Texas Coastal Uplands aquifer system consists of two main aquifers: the Paleocene/Eocene Carrizo-Wilcox aquifer and the Eocene Claiborne aquifer, which is situated above the Carrizo-Wilcox aquifer. Both aquifers consist of sand, silt, gravel, and clay and are used extensively for agricultural irrigation, domestic, municipal, and industrial water supply. Groundwater in the Carrizo-Wilcox aquifer is present under unconfined and artesian conditions. Water-table conditions usually occur in areas where the aquifer outcrops, and artesian conditions occur where the aquifer is overlain by confining beds. Well yields are usually 500 gal/min (Thorkildsen and Price 1991).

From Polk County to the southern extent of the proposed route, the ROW is present above the Texas Coastal Lowlands aquifer system. The three main aquifers in this system are the Miocene Jasper aquifer, overlain by the late Tertiary Evangeline, which is overlain by the Quaternary Chicot aquifer (Ryder 1996). These three aquifers are composed of sand with interbedded silt and clay. The Evangeline and Chicot aquifers are used extensively for water supply in this area; water levels range from 100 to 300 feet bgs.

The proposed pipeline route does not cross any sole-source aquifers in Texas, as designated by EPA Region 6 (EPA 2009).

Nearby Public Water Supply Wells and Private Water Wells

Within 1 mile of the proposed Gulf Coast Segment pipeline route in Lamar, Wood, Smith, Rusk, Nacogdoches, Angelina, Polk, and Liberty counties, 53 PWS wells are present. Within 1 mile of the proposed Houston Lateral pipeline route, 145 PWS wells are present in Liberty and Harris counties. The proposed Project would pass within 1 mile of 36 SWPAs in Texas. A total of three private water wells are located within approximately 100 feet of the proposed pipeline route within Smith and Chambers counties.

Likely Depth to Groundwater

Estimates of the likely depth to groundwater at existing well locations within 1 mile of the proposed pipeline in Texas are provided in Figure 3.3.1-5. As depicted in Figure 3.3.1-5, the numbers of wells within 1 mile of the proposed pipeline that fall within each groundwater depth category are as follows:

- Category A (very shallow): 11
- Category B (shallow): 11
- Category C (unclear but potentially very shallow): 52
- Category D (unclear but potentially shallow): 25
- Category E (deep): 55

There have been no substantive changes to Sections 3.3.1.2 and 3.3.1.3 and therefore they are not included in the SDEIS. The draft EIS subsection can be downloaded at www.keystonepipeline-xl.state.gov.

3.3.2 Potential Impacts and Mitigation

There have been no substantive changes to this section and therefore it is not included in the SDEIS. The draft EIS subsection can be downloaded at www.keystonepipeline-xl.state.gov.

3.3.3 Connected Actions

There have been no changes to the environmental assessment for the electrical distribution lines and substations or the Big Bend to Witten 230-kV transmission line (formerly the Lower Brule to Witten 230-kV transmission line). Potential impacts associated with the Bakken Marketlink Project and the Cushing Marketlink Project are addressed in Section 3.15 of this SDEIS.

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[FIGURE PLACEHOLDER]

3.3.1-1 Key Aquifers and Potable Water Wells within 2-mile Corridor (Montana)

3.3.1-2 Key Aquifers and Potable Water Wells within 2-mile Corridor (South Dakota)

3.3.1-3 Key Aquifers and Potable Water Wells within 2-mile Corridor (Nebraska)

3.3.1-4 Key Aquifers and Potable Water Wells within 2-mile Corridor (Oklahoma)

3.3.1-5 Key Aquifers and Potable Water Wells within 2-mile Corridor (Texas)

3.3.1-6 Northern High Plains Aquifer System Hydrogeologic Units

3.4 WETLANDS

There have been no changes to the environmental assessment presented in this section, including the assessment of the electrical distribution lines and substations and the Big Bend to Witten 230-kV transmission line (formerly the Lower Brule to Witten 230-kV transmission line); therefore it is not included in the SDEIS. The draft EIS subsection can be downloaded at www.keystonepipeline-xl.state.gov. Potential impacts associated with the Bakken Marketlink Project and the Cushing Marketlink Project are addressed in Section 3.15 of this SDEIS.

3.5 TERRESTRIAL VEGETATION

There have been no changes to the environmental assessment presented in this section, including the assessment of the electrical distribution lines and substations and the Big Bend to Witten 230-kV transmission line (formerly the Lower Brule to Witten 230-kV transmission line); therefore it is not included in the SDEIS. The draft EIS subsection can be downloaded at www.keystonepipeline-xl.state.gov. Potential impacts associated with the Bakken Marketlink Project and the Cushing Marketlink Project are addressed in Section 3.15 of this SDEIS.

3.6 WILDLIFE

There have been no changes to the environmental assessment presented in this section, including the assessment of the electrical distribution lines and substations and the Big Bend to Witten 230-kV transmission line (formerly the Lower Brule to Witten 230-kV transmission line); therefore it is not included in the SDEIS. The draft EIS subsection can be downloaded at www.keystonepipeline-xl.state.gov. Potential impacts associated with the Bakken Marketlink Project and the Cushing Marketlink Project are addressed in Section 3.15 of this SDEIS.

3.7 FISHERIES

There have been no changes to the environmental assessment presented in this section, including the assessment of the electrical distribution lines and substations and the Big Bend to Witten 230-kV transmission line (formerly the Lower Brule to Witten 230-kV transmission line); therefore it is not included in the SDEIS. The draft EIS subsection can be downloaded at www.keystonepipeline-xl.state.gov. Potential impacts associated with the Bakken Marketlink Project and the Cushing Marketlink Project are addressed in Section 3.15 of this SDEIS.

3.8 THREATENED AND ENDANGERES SPECIES AND SPECIES OF CONSERVATION CONCERN

There have been no changes to the environmental assessment presented in this section, including the assessment of the electrical distribution lines and substations and the Big Bend to Witten 230-kV transmission line (formerly the Lower Brule to Witten 230-kV transmission line); therefore it is not included in the SDEIS. The draft EIS subsection can be downloaded at www.keystonepipeline-xl.state.gov. Potential impacts associated with the Bakken Marketlink Project and the Cushing Marketlink Project are addressed in Section 3.15 of this SDEIS.

3.9 LAND USE, RECREATION, AND VISUAL RESOURCES

There have been no changes to the environmental assessment presented in this section, including the assessment of the electrical distribution lines and substations and the Big Bend to Witten 230-kV transmission line (formerly the Lower Brule to Witten 230-kV transmission line); therefore it is not

included in the SDEIS. The draft EIS subsection can be downloaded at www.keystonepipeline-xl.state.gov. Potential impacts associated with the Bakken Marketlink Project and the Cushing Marketlink Project are addressed in Section 3.15 of this SDEIS.

3.10 SOCIOECONOMICS

Supplemental information on minority populations and low-income populations along the proposed route is presented below in response to comments on the draft EIS expressing concern about the potential for environmental justice impacts during construction and operation of the proposed Project. As noted below, the inclusion of this expanded information in the analysis did not affect results of the assessment of the potential environmental justice impacts due to construction and normal operation of the proposed Project. Impacts associated with unintentional releases from the proposed Project are addressed in Section 3.13.

3.10.1 Socioeconomics and Environmental Justice (New Title)

This section was titled *Environmental Setting* in the draft EIS. There have been no substantive changes to this section and therefore it is not included in the SDEIS. The draft EIS subsection can be downloaded at www.keystonepipeline-xl.state.gov.

3.10.1.1 Environmental Setting (New Title)

This section was titled *Region of Influence* in the draft EIS. There have been no substantive changes to this section and therefore it is not included in the SDEIS. The draft EIS subsection can be downloaded at www.keystonepipeline-xl.state.gov.

Population

This was Section 3.10.1.2 in the draft EIS. There have been no substantive changes to this section and therefore it is not included in the SDEIS. The draft EIS subsection can be downloaded at www.keystonepipeline-xl.state.gov.

Housing

This was Section 3.10.1.3 in the draft EIS. There have been no substantive changes to this section and therefore it is not included in the SDEIS. The draft EIS subsection can be downloaded at www.keystonepipeline-xl.state.gov.

Economic Activity

This was Section 3.10.1.4 in the draft EIS. There have been no substantive changes to this section and therefore it is not included in the SDEIS. The draft EIS subsection can be downloaded at www.keystonepipeline-xl.state.gov.

Tax Revenue

This was Section 3.10.1.5 in the draft EIS. There have been no substantive changes to this section and therefore it is not included in the SDEIS. The draft EIS subsection can be downloaded at www.keystonepipeline-xl.state.gov.

Public Services

This was Section 3.10.1.6 in the draft EIS. There have been no substantive changes to this section and therefore it is not included in the SDEIS. The draft EIS subsection can be downloaded at www.keystonepipeline-xl.state.gov.

Environmental Justice

This was Section 3.10.1.7 in the draft EIS.

Executive Order 12898, *Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations* directs Federal agencies to identify and address, as appropriate, disproportionately high and adverse health or environmental effects of their programs, policies, and activities on minority populations and low-income populations. Environmental justice refers to the "fair treatment and meaningful involvement of all people regardless of race, color, national origin, or income with respect to the development, implementation, and enforcement of environmental laws, regulations, and policies" (EPA 2007). The Council on Environmental Quality (CEQ) has provided guidance for addressing environmental justice (CEQ 1997).

In the draft EIS, minority and low-income populations along the proposed Project corridor were screened at the county level for the 58 counties in 6 states that would be crossed by the proposed Project. Several commenters on the draft EIS requested additional detailed analysis on minority and low-income populations that could be impacted by the proposed Project. In response, DOS has evaluated census block groups within a 4-mile-wide analysis area centered on the pipeline and associated pump stations.

Methodology to Identify and Locate Minority and Low-Income Populations

Minority populations are members of one of the following racial groups: African-Americans, American Indians or Alaskan Natives, Asians, Native Hawaiians or other Pacific Islanders, "Other" races, or multi-racial (CEQ 1997). The racial population is expressed in terms of the number and/or percentage of people that are minorities in an area. The sum of these racial minority populations is referred to as the aggregate racial minority population for counties and census block groups. Minority population was determined using US Census Summary File 1 Category P6: Race. Persons of Hispanic/Latino origin are referred to as an ethnic minority, may be of any race including the identified racial populations, and thus are identified as a separate subcategory. Hispanic or Latino population was determined using US Census Summary File 1 Category P7: Hispanic or Latino by Race. Low-income population was determined using U.S. Census Summary File 3 Category P87: Poverty Status in 1999 by Age.

Census Geographic Unit Criteria

Determination of Potentially Affected Area for Analysis

In order to assess potential impacts to minority and low-income populations from construction and operation of the proposed Project as well as from potential discharge incidents, DOS considered the types of effects and the areal distribution of these effects as a function of distance from the proposed Project pipeline centerline to establish a potentially affected area for analysis. Effects considered included potential dust and noise generated by construction, disruption to traffic patterns associated with the movement of construction materials and equipment, and potential health impacts in the unlikely event of a substantial discharge from the proposed Project during operation.

The determination of the precise distance from the proposed Project centerline where these effects could impact minority or low-income populations is problematic given the length of the proposed Project, the diversity of terrain the proposed Project would cross, and the variation in population density along the proposed Project corridor. Of particular concern would be any potential health effects to minority or low-income populations resulting from a crude oil discharge. The potential effects of a crude oil discharge are addressed in detail in Section 3.13. As discussed in Section 3.13, a 1979 pipeline crude oil release near Bemidji, Minnesota can be used as an example of possible terrestrial and subsurface crude oil distribution in the unlikely event of a substantial crude oil discharge. In that release a substantial quantity of crude oil (approximately 10,700 bbl) was released to the environment. It affected the ground surface over an area that extended approximately 1,200 feet northwest to southeast and 900 feet northeast to southwest. In the subsurface groundwater, the dissolved contaminant plume has extended downgradient over time approximately 650 feet. Using these dimensions as a surrogate for a potential substantial discharge along the proposed Project corridor and considering that the distribution of volatile organic compounds in the air would potentially extend beyond these dimensions depending on climatic conditions at the time of the discharge, DOS defined a 4-mile-wide affected analysis area that extends a distance of 2 miles on either side of the proposed Project centerline. This conservative affected area should adequately address the uncertainty inherent in the analysis, given that actual discharge volumes and the actual release location in the unlikely event of a substantial discharge from the proposed Project are not known.

Population within County

Minority or low-income populations at the county level can be assessed using an EPA GIS Mapping Tool to identify areas of environmental justice concern within a state. The key socioeconomic demographic data pertinent for environmental justice are the racial/ethnic composition and income status of affected counties. The proposed Project corridor would cross 58 counties in six states. However, DOS analyzed county population data within a 4-mile-wide analysis area, and as a result an additional county (Payne County, Oklahoma) was added to this analysis resulting in an evaluation of 59 counties.

Population within Census Block Groups

A census block group is the smallest geographic area for which the Census Bureau provides consistent sample data and generally contains a population between 600 and 3,000 individuals. These data are summarized in Table 3.10.1-9 from north to south along the proposed alignment. The U.S. Census Bureau's 2000 census block groups were identified within the 4-mile-wide analysis area.

Geographic Information Systems (GIS) and U.S. Census Bureau's 2000 census block group data were then used to determine the minority and low-income characteristics. As indicated in Table 3.10.1-10, the 4-mile-wide analysis area for the proposed Project encompasses or intersects 287 census block groups across 6 states. Of the 287 census block groups identified, 63 are along the proposed Steele City Segment, 5 are near the proposed new pump stations on the Cushing Extension in Kansas, 180 are along the proposed Gulf Coast Segment, and 43 are along the proposed Houston Lateral. Four census block groups in Liberty County, Texas, fall within the 4-mile-wide analysis area for both the proposed Gulf Coast Segment and the proposed Houston Lateral but are counted only once in the totals.

A census block group was included in the 4-mile-wide analysis area if its boundaries were fully contained in the area, or if any part of the census block group was contained in the area. Fully contained census block groups are shown in Table 3.10.1-10. There were no fully contained census block groups in any states in the proposed Steele City Segment or pump stations in Kansas. On the proposed Gulf Coast Segment, one fully contained group was identified in Lincoln County, Oklahoma at Stroud and Angelina County, Texas at Diboll, and seven were identified in Jefferson County, Texas at Nederland and Central Gardens. For the proposed Houston Lateral, one fully contained group was identified in Harris County at

Channelview. All of the remaining census block groups east of Houston on the proposed Houston Lateral are only partially within the proposed Project analysis area. As stated previously the analysis is likely to be conservative since portions of most of the census block groups analyzed are outside of the 4-mile-wide analysis area.

Population Percentage Criteria

To assess potential environmental justice concerns related to the proposed Project in accordance with CEQ Guidance, DOS performed two separate proximity based analyses within the 4-mile-wide analysis area. These two separate analyses include:

- A *50 percent criterion* population analysis to determine those counties and census block groups along the proposed Project corridor where minority and/or low-income individuals are equal to or exceed 50 percent of the population of the census block group.
- A *meaningfully greater criterion* population analysis in which minority and/or low-income population percentages within counties and individual census block groups were compared to state-wide reference populations for the purposes of the evaluation. A meaningfully greater population was defined as a minority and/or low-income population within an individual county or census block group that was equal to or greater than 150 percent (1.5 times) of the state-wide reference population. While some analyses consider a minority and/or low-income population within an individual county or census block group equal to or greater than 120 percent (1.2 times) of the state-wide reference population to be appropriate, given the low population base across most of the proposed Project corridor, the 150 percent criterion was selected for the analysis of the proposed Project. DOS considers comparisons to the state-wide percentage a much more appropriate comparison than comparisons to nation-wide percentages for determining potential environmental justice concerns for linear energy projects. Comparisons to nationwide percentages are more appropriate for assessing impacts associated with facility siting where alternatives to the proposed facility are very widely dispersed geographically.

If a census block group within the proposed Project analysis area met either of these criteria, DOS assumed that there is a potential for environmental justice populations to experience disproportionate effects.

TABLE 3.10.1-9
Minority and Low-Income Populations as Percentage of Total County Populations in Affected Counties in 4-Mile-Wide Analysis Area

County	Total Population	Low-Income	African American	Native American or Alaskan Native	Asian or Pacific Islander	Other[a]	Two or More Races	Aggregate (Total) of Racial Minorities	Hispanic or Latino
Steele City Segment									
Montana									
Phillips	4,601	828 (18.0%)	4 (0.1%)	379 (8.2%)	34 (0.7%)	2 (0.04%)	96 (2.1%)	515 (11.2%)	24 (0.5%)
Valley	7,675	1,026 (13.4%)	7 (0.1%)	634 (9.4%*)	11 (0.2%)	40 (0.3%)	168 (1.8%)	860 (11.2%)	118 (1.5%)
McCone	1,977	331 (16.7%)	11 (0.6%*)	27 (1.4%)	2 (0.1%)	4 (0.2%)	30 (1.5%)	74 (3.7%)	24 (1.2%)
Dawson	9,059	1,285 (14.2%)	46 (0.5%)	87 (1.0%)	5 (0.1%)	2 (0.02%)	54 (0.6%)	194 (2.1%)	69 (0.8%)
Prairie	1,199	202 (16.8%)	0 (0.0%)	11 (0.9%)	2 (0.2%)	0 (0.0%)	4 (0.3%)	17 (1.4%)	4 (0.3%)
Fallon	2,837	349 (12.3%)	9 (0.3%)	12 (0.4%)	4 (0.1%)	0 (0.0%)	7 (0.2%)	32 (1.1%)	17 (0.6%)
Subtotal Montana	*27,348*	*4,021 (14.7%)*	*77 (0.3%)*	*1,150 (4.2%)*	*58 (0.2%)*	*48 (0.2%)*	*359 (1.3%)*	*1,692 (6.2%)*	*256 (0.9%)*
Montana Exceedance Criteria[b]		21.9%	0.5%	9.3%	0.9%	0.9%	2.6%	14.2%	3.0%
South Dakota									
Harding	1,353	277 (20.5%*)	7 (0.5%)	20 (1.5%)	0 (0.0%)	0 (0.0%)	0 (0.0%)	27 (2.0%)	7 (0.5%)
Butte	9,094	1,147 (12.6%)	2 (0.02%)	86 (0.9%)	48 (0.5%)	76 (0.8%*)	127 (1.4%)	339 (3.7%)	309 (3.4%*)
Perkins	3,363	561 (16.7%)	3 (0.1%)	70 (2.1%)	13 (0.4%)	4 (0.1%)	34 (1.0%)	124 (3.7%)	3 (0.1%)
Meade	24,253	2,195 (9.1%)	331 (1.4%*)	549 (2.3%)	178 (0.7%)	173 (0.7%*)	573 (2.4%*)	1,804 (7.4%)	435 (1.8%)
Pennington	88,656	9,967 (11.3%)	677 (0.8%)	6,748 (7.6%)	954 (1.1%*)	665 (0.8%*)	2,707 (3.1%*)	11,751 (13.3%)	2,335 (2.6%*)

TABLE 3.10.1-9
Minority and Low-Income Populations as Percentage of Total County Populations in Affected Counties in 4-Mile-Wide Analysis Area

County	Total Population	Low-Income	African American	Native American or Alaskan Native	Asian or Pacific Islander	Other[a]	Two or More Races	Aggregate (Total) of Racial Minorities	Hispanic or Latino
Haakon	2,196	298 (13.6%)	0 (0.0%)	57 (2.6%)	14 (0.6%)	0 (0.0%)	8 (0.4%)	79 (3.6%)	3 (0.1%)
Jones	1,193	188 (15.8%)	7 (0.6%)	18 (1.5%)	0 (0.0%)	0 (0.0%)	27 (2.3%*)	52 (4.4%)	0 (0.0%)
Lyman	3,895	941 (24.2%*)	2 (0.1%)	1,249 (32.1%*)	8 (0.2%)	0 (0.0%)	85 (2.2%*)	1,344 (34.5%*)	1 (0.03%)
Tripp	6,430	1,254 (18.4%)	0 (0.0%)	671 (11.2%)	19 (0.1%)	0 (0.0%)	89 (1.2%)	779 (12.1%)	46 (0.9%)
Subtotal South Dakota	*140,433*	*16,828 (12.0%)*	*1,029 (0.7%)*	*9,468 (6.7%)*	*1,234 (0.9%)*	*918 (0.7%)*	*3,650 (2.6%)*	*16,299 (11.6%)*	*3,139 (2.2%)*
South Dakota Exceedance Criteria[b]		19.8%	0.9%	12.5%	0.9%	0.5%	2.0%	17.0%	2.1%
Nebraska									
Keya Paha	983	264 (26.9%*)	0 (0.0%)	0 (0.0%)	0 (0.0%)	0 (0.0%)	5 (0.5%)	5 (0.5%)	24 (2.4%)
Rock	1,756	375 (21.4%*)	0 (0.0%)	26 (1.5%*)	5 (0.3%)	0 (0.0%)	8 (0.5%)	39 (2.2%)	11 (0.6%)
Holt	11,551	1,477 (12.8%)	2 (0.02%)	34 (0.3%)	11 (0.1%)	51 (0.4%)	19 (0.2%)	117 (1.0%)	72 (0.6%)
Garfield	1,902	232 (12.2%)	0 (0.0%)	3 (0.1%)	2 (0.1%)	2 (0.1%)	9 (0.5%)	16 (0.8%)	20 (1.1%)
Wheeler	886	183 (20.7%*)	2 (0.2%)	5 (0.6%)	0 (0.0%)	7 (0.8%)	2 (0.2%)	16 (1.8%)	7 (0.8%)
Greeley	2,714	387 (14.3%)	8 (0.3%)	0 (0.0%)	3 (0.1%)	14 (0.5%)	2 (0.1%)	27 (1.0%)	16 (0.6%)
Boone	6,259	638 (10.2%)	0 (0.0%)	7 (0.1%)	8 (0.1%)	19 (0.3%)	29 (0.5%)	63 (1.0%)	59 (0.9%)
Nance	4,038	518 (12.8%)	0 (0.0%)	6 (0.1%)	8 (0.2%)	3 (0.1%)	37 (0.9%)	54 (1.3%)	49 (1.2%)
Merrick	8,204	713 (8.7%)	7 (0.1%)	6 (0.1%)	28 (0.3%)	33 (0.4%)	27 (0.3%)	101 (1.2%)	158 (1.9%)

TABLE 3.10.1-9
Minority and Low-Income Populations as Percentage of Total County Populations in Affected Counties in 4-Mile-Wide Analysis Area

County	Total Population	Low-Income	African American	Native American or Alaskan Native	Asian or Pacific Islander	Other[a]	Two or More Races	Aggregate (Total) of Racial Minorities	Hispanic or Latino
Hamilton	9,403	690 (7.3%)	19 (0.2%)	0 (0.0%)	1 (0.01%)	27 (0.3%)	32 (0.3%)	79 (0.8%)	66 (0.7%)
York	14,598	1,170 (8.0%)	93 (0.6%)	30 (0.2%)	62 (0.4%)	149 (1.0%)	99 (0.7%)	433 (3.0%)	258 (1.8%)
Fillmore	6,634	498 (7.5%)	2 (0.03%)	33 (0.5%)	10 (0.2%)	63 (0.9%)	46 (0.7%)	154 (2.3%)	76 (1.1%)
Saline	13,843	1,213 (8.8%)	49 (0.4%)	120 (0.9%)	158 (1.1%)	498 (3.6%)	89 (0.6%)	914 (6.6%)	879 (6.3%)
Jefferson	8,333	733 (8.8%)	3 (0.04%)	38 (0.5%)	8 (0.1%)	17 (0.2%)	57 (0.7%)	123 (1.5%)	74 (0.9%)
Subtotal Nebraska	*91,104*	*9,091 (10.0%)*	*185 (0.2%)*	*308 (0.3%)*	*304 (0.3%)*	*883 (1.0%)*	*461 (0.5%)*	*2,141 (2.4%)*	*1,769 (1.9%)*
Nebraska Exceedance Criteria[b]		14.6%	6.0%	1.4%	2.0%	4.2%	2.1%	15.6%	8.3%
New Cushing Extension Pump Stations									
Kansas									
Clay	8,822	867 (9.8%)	20 (0.2%)	16 (0.2%)	12 (0.1%)	30 (0.3%)	163 (1.8%)	241 (2.7%)	92 (1.0%)
Butler	59,482	4,187 (7.0%)	806 (1.4%)	709 (1.2%)	212 (0.4%)	455 (0.8%)	1,031 (1.7%)	3,213 (5.4%)	1,140 (1.9%)
Subtotal Kansas	*68,304*	*5,054 (7.4%)*	*826 (1.2%)*	*725 (1.1%)*	*224 (0.3%)*	*485 (0.7%)*	*1,194 (1.7%)*	*3,454 (5.1%)*	*1,232 (1.8%)*
Kansas Exceedance Criteria[b]		14.9%	8.6%	1.4%	2.6%	5.2%	3.2%	20.8%	10.5%
Gulf Coast Segment									
Oklahoma									
Payne	68,186	12,431 (18.2%)	2,550 (3.7%)	3,000 (4.4%)	1,906 (2.8%*)	629 (0.9%)	2,580 (3.8%)	10,665 (15.6%)	1,640 (2.4%)
Creek	67,367	8,924	1,953	5,757	123 (0.2%)	462 (0.7%)	3,874 (5.8%)	12,169	1,390 (2.1%)

TABLE 3.10.1-9
Minority and Low-Income Populations as Percentage of Total County Populations in Affected Counties in 4-Mile-Wide Analysis Area

County	Total Population	Low-Income	African American	Native American or Alaskan Native	Asian or Pacific Islander	Other[a]	Two or More Races	Aggregate (Total) of Racial Minorities	Hispanic or Latino
		(13.2%)	(2.9%)	(8.5%)				(18.1%)	
Lincoln	32,080	4,591 (14.3%)	636 (2.0%)	2,086 (6.5%)	103 (0.3%)	124 (0.4%)	1,448 (4.5%)	4,397 (13.7%)	334 (1.0%)
Okfuskee	11,814	2,508 (21.2%)	1,194 (10.1%)	2,160 (18.3%*)	15 (0.1%)	102 (0.9%)	602 (5.1%)	4,073 (34.5%)	215 (1.8%)
Seminole	24,894	5,055 (20.3%)	1,454 (5.8%)	4,213 (16.9%*)	104 (0.4%)	212 (0.9%)	1,340 (5.4%)	7,323 (29.4%)	562 (2.3%)
Hughes	14,154	2,822 (19.9%)	645 (4.6%)	2,230 (15.8%*)	16 (0.1%)	82 (0.6%)	851 (6.0%)	3,824 (27.0%)	310 (2.2%)
Pontotoc	35,143	5,601 (15.9%)	835 (2.4%)	5,469 (15.6%*)	122 (0.3%)	186 (0.5%)	1,949 (5.5%)	8,561 (24.4%)	637 (1.8%)
Coal	6,031	1,366 (22.6%*)	22 (0.4%)	1,019 (16.9%*)	18 (0.3%)	80 (1.3%)	353 (5.9%)	1,492 (24.7%)	183 (3.0%)
Atoka	13,879	2,426 (17.5%)	813 (5.9%)	1,613 (11.6%)	8 (0.1%)	59 (0.4%)	881 (6.3%)	3,374 (24.3%)	139 (1.0%)
Bryan	36,534	6,529 (17.9%)	536 (1.5%)	4,694 (12.8%*)	128 (0.4%)	399 (1.1%)	1,610 (4.4%)	7,367 (20.2%)	823 (2.3%)
Subtotal Oklahoma	*310,082*	*52,253 (16.9%)*	*10,638 (3.4%)*	*32,241 (10.4%)*	*2,543 (0.8%)*	*2,335 (0.8%)*	*15,488 (5.0%)*	*63,245 (20.4%)*	*6,233 (2.0%)*
Oklahoma Exceedance Criteria[b]		22.1%	11.4%	11.9%	2.0%	3.6%	6.8%	35.6%	7.8%
Texas									
Fannin	31,242	3,878 (12.4%)	2,451 (7.8%)	285 (0.9%*)	85 (0.3%)	929 (3.0%)	445 (1.4%)	4,195 (13.4%)	1,769 (5.7%)
Lamar	48,499	7,737 (16.2%)	6,257 (13.5%)	530 (1.1%*)	164 (0.4%)	689 (1.2%)	770 (1.4%)	8,410 (17.3%)	1,715 (3.3%)
Delta	5,327	911 (17.1%)	503 (9.4%)	31 (0.6%)	20 (0.4%)	4 (0.1%)	142 (2.7%)	700 (13.1%)	43 (0.8%)
Hopkins	31,960	4,580 (14.6%)	2,415 (8.0%)	283 (0.7%)	117 (0.2%)	1,523 (4.6%)	498 (1.4%)	4,836 (15.1%)	2,960 (9.3%)

TABLE 3.10.1-9
Minority and Low-Income Populations as Percentage of Total County Populations in Affected Counties in 4-Mile-Wide Analysis Area

County	Total Population	Low-Income	African American	Native American or Alaskan Native	Asian or Pacific Islander	Other[a]	Two or More Races	Aggregate (Total) of Racial Minorities	Hispanic or Latino
Franklin	9,458	1,448 (15.3%)	380 (4.0%)	73 (0.8%)	8 (0.1%)	501 (5.3%)	61 (0.6%)	1,023 (10.8%)	830 (8.8%)
Wood	36,752	5,051 (11.9%)	2,261 (6.1%)	140 (0.6%)	110 (0.2%)	963 (2.9%)	488 (1.1%)	3,962 (10.8%)	1,977 (5.7%)
Upshur	35,291	5,167 (14.6%)	3,529 (10.0%)	150 (0.4%)	104 (0.3%)	846 (2.4%)	394 (1.1%)	5,023 (14.2%)	1,336 (3.8%)
Smith	174,706	23,543 (13.5%)	33,296 (19.1%*)	726 (0.4%)	1159 (0.7%)	10,066 (5.8%)	2,288 (1.3%)	47,535 (27.2%)	19,395 (11.1%)
Rusk	47,372	6,526 (13.8%)	9,175 (19.4%*)	174 (0.4%)	130 (0.3%)	1,735 (3.7%)	476 (1.0%)	11,690 (24.7%)	3,934 (8.3%)
Cherokee	46,659	7,823 (16.8%)	7,689 (16.5%)	126 (0.3%)	88 (0.2%)	3,493 (7.5%)	462 (1.0%)	11,858 (25.4%)	6,183 (13.3%)
Nacogdoches	59,203	12,743 (21.5%)	9,827 (16.6%)	249 (0.4%)	478 (0.6%)	3,174 (5.4%)	1,093 (1.8%)	14,821 (25.0%)	6,700 (11.3%)
Angelina	80,130	12,241 (15.3%)	11,851 (14.8%)	277 (0.3%)	548 (0.7%)	5,945 (7.4%)	1,245 (1.6%)	19,866 (24.8%)	11,282 (14.1%)
Polk	41,133	6,540 (17.5%)	5,270 (13.2%)	706 (1.7%*)	253 (0.6%)	1,631 (3.7%)	609 (1.3%)	8,469 (20.6%)	3,970 (9.4%)
Liberty	70,154	9,296 (13.3%)	8,884 (12.7%)	341 (0.5%)	241 (0.3%)	4,098 (5.8%)	1,102 (1.6%)	14,666 (20.9%)	7,661 (10.9%)
Hardin	48,073	5,314 (11.1%)	3,328 (6.9%)	119 (0.2%)	278 (0.6%)	304 (0.6%)	548 (1.1%)	4,577 (9.5%)	1,176 (2.4%)
Jefferson	252,051	41,142 (16.3%)	84,970 (33.7%*)	996 (0.4%)	7,159 (2.8%)	10,648 (4.2%)	3,707 (1.5%)	107,480 (42.6%)	26,664 (10.6%)
Subtotal Texas - Gulf Coast Segment	*1,018,010*	*153,940 (15.1%)*	*192,086 (18.9%)*	*5,206 (0.5%)*	*10,942 (1.1%)*	*46,549 (4.6%)*	*14,328 (1.4%)*	*77,025 (7.6%)*	*97,595 (9.6%)*
Texas Exceedance Criteria[b]		23.1%	17.3%	0.9%	4.2%	17.6%	3.8%	43.7%	48.0%
Houston Lateral									

TABLE 3.10.1-9
Minority and Low-Income Populations as Percentage of Total County Populations in Affected Counties in 4-Mile-Wide Analysis Area

County	Total Population	Low-Income	African American	Native American or Alaskan Native	Asian or Pacific Islander	Other[a]	Two or More Races	Aggregate (Total) of Racial Minorities	Hispanic or Latino
Liberty	70,154	9,296 (13.3%)	8,884 (12.7%)	341 (0.5%)	241 (0.3%)	4,098 (5.8%)	1,102 (1.6%)	14,666 (20.9%)	7,661 (10.9%)
Chambers	26,031	2,833 (10.9%)	2,508 (9.6%)	94 (0.4%)	89 (0.3%)	1,619 (6.2%)	355 (1.4%)	4,665 (17.9%)	2,836 (10.9%)
Harris	3,400,578	503,234 (14.8%)	627,111 (18.4%*)	14,670 (0.4%)	173,491 (5.1%*)	488, 480 (14.4%)	102,669 (3.0%)	1,406,421 (41.4%)	1,120,625 (32.9%)
Subtotal Texas - Houston Lateral	3,496,763	*515,363 (14.7%)*	*638,503 (18.3%)*	*15,105 (0.4%)*	*173,821 (5.0%)*	*494, 197 (14.1%)*	*104, 126 (3.0%)*	*1,425,752 (40.8%)*	*1,131,122 (32.4%)*
Texas Exceedance Criteria[b]		23.1%	17.3%	0.9%	4.2%	17.6%	3.8%	43.7%	48.0%
Subtotal Texas	*4,444,619*	*660,007 (14.8%)*	*821,705 (18.5%)*	*19,970 (0.4%)*	*184,522 (4.2%)*	*536,648 (12.1%)*	*117,352 (2.6%)*	*1,488,111 (33.5%)*	*1,221,056 (27.5%)*
Project Total	**5,081,890**	**747,254 (14.7%)**	**834,460 (16.4%)**	**63,862 (1.3%)**	**188,885 (3.7%)**	**541, 317 (10.7%)**	**138, 504 (2.7%)**	**1,574,942 (31.0%)**	**1,233,685 (24.3%)**

[a] The "Other" racial category accounts for those individuals who marked "Some other race", a category included in the 2000 Census for respondents who were unable to identify with the five Office of Management and Budget's race categories. Respondents who provided write-in entries such as Moroccan, South African, Belizean, or a Hispanic origin (for example, Mexican, Puerto Rican, or Cuban) are included in the "Other" race category. (http://www.census.gov/prod/2001pubs/c2kbr01-1.pdf).

[b] State-wide exceedance criteria percentages are 1.5 times the actual Environmental Justice group population percentages for each state.

* Denotes Minority populations and low-income individuals that were meaningfully greater than the corresponding minority population or low-income individual at the state level in the relevant racial/ethnic or low-income category columns.

Sources: U.S. Census Bureau. 2002. Census Block Group SF3: 2000. Table P6 – Race. Table P7 – Hispanic or Latino by Race. Washington, D.C.

U.S. Census Bureau. 2002. Census Block Group SF3: 2000. Table P87 – Poverty Status in 1999 by Age. Washington, D.C.

TABLE 3.10.1-10
Minority and Low-Income Populations as Percentage of Census Block Group Populations in 4-Mile-Wide Analysis Area

County	Total Number of Census Block Groups	Low-Income	African American	Native American or Alaskan Native	Asian or Pacific Islander	Other	Two or More Races	Aggregate (Total) of Racial Minorities	Hispanic or Latino
Steele City Segment									
Montana									
Phillips	1	314 (24.4%)	0 (0%)	85 (6.6%)	5 (0.4%)	2 (0.2%)	23 (1.8%)	115 (9.0%)	10 (0.8%)
Valley	6	593 (15.3%)	7 (0.2%)	550 (14.2%)	11 (0.3%)	19 (0.5%)	74 (1.9%)	661 (17.1%)	28 (0.1%)
McCone	3	331 (16.7%)	11 (0.6%)	27 (1.4%)	2 (0.1%)	4 (0.2%)	30 (1.5%)	74 (3.7)	24 (1.2%)
Dawson	2	186 (18.0%)	0 (0%)	2 (0.2%)	0 (0%)	0 (0%)	6 (0.6%)	8 (0.8%)	2 (0.2%)
Prairie	1	152 (26.5%)	0 (0%)	3 (0.5%)	0 (0%)	0 (0%)	4 (0.7%)	7 (1.2%)	2 (0.3%)
Fallon	3	349 (12.3%)	9 (0.3%)	12 (0.4%)	4 (0.1%)	0 (0%)	7 (0.3%)	32 (1.1%)	17 (0.6%)
Carter	1	130 (14.9%)	4 (0.5%)	3 (0.3%)	0 (0%)	0 (0%)	2 (0.2%)	9 (1.0%)	0 (0%)
Subtotal Montana	*17*	*2,055 (16.5%)*	*31 (0.2%)*	*682 (5.5%)*	*22 (0.2%)*	*25 (0.2%)*	*146 (1.2%)*	*906 (7.3%)*	*83 (0.7%)*
South Dakota									
Harding	2	277 (20.5%)	7 (0.5%)	20 (1.5%)	0 (0%)	0 (0%)	0 (0%)	27 (2.0%)	7 (0.5%)
Butte	1	167 (13.9%)	0 (0%)	0 (0%)	0 (0%)	2 (0.2%)	12 (1.0%)	14 (1.2%)	10 (0.8%)
Perkins	1	239 (21.8%)	0 (0%)	6 (0.5%)	0 (0%)	0 (0%)	13 (1.2%)	19 (1.7%)	3 (0.3%)
Meade	2	261 (16.5%)	0 (0%)	56 (3.5%)	6 (0.4%)	0 (0%)	10 (0.6%)	72 (4.5%)	12 (0.8%)
Ziebach	1	392 (59.8%)	0 (0%)	591 (90.2%)	2 (0.3%)	3 (0.5%)	3 (0.5%)	599 (91.5%)	7 (1.1%)
Pennington	1	91 (17.6%)	0 (0%)	9 (1.7%)	0 (0%)	0 (0%)	9 (1.7%)	18 (3.4%)	0 (0%)
Haakon	2	202 (18.0%)	0 (0%)	20 (1.8%)	9 (0.8%)	0 (0%)	1 (0.1%)	30 (2.7%)	0 (0%)
Jones	1	188 (15.8%)	7 (0.6%)	18 (1.5%)	0 (0%)	0 (0%)	27 (2.3%)	52 (4.4%)	0 (0%)
Lyman	1	149 (14.0%)	0 (0%)	8 (0.7%)	0 (0%)	0 (0%)	23 (2.2%)	31 (2.9%)	0 (0%)

TABLE 3.10.1-10
Minority and Low-Income Populations as Percentage of Census Block Group Populations in 4-Mile-Wide Analysis Area

County	Total Number of Census Block Groups	Low-Income	African American	Native American or Alaskan Native	Asian or Pacific Islander	Other	Two or More Races	Aggregate (Total) of Racial Minorities	Hispanic or Latino
Tripp	8	1,254 (19.5%)	0 (0%)	671 (10.4%)	19 (0.3%)	0 (0%)	89 (1.4%)	779 (12.1%)	46 (0.7%)
Gregory	1	188 (25.6%)	5 (0.7%)	44 (6.0%)	0 (0%)	0 (0%)	4 (0.5%)	53 (7.2%)	3 (0.4%)
Subtotal South Dakota	*21*	*3,408 (20.1%)*	*19 (0.1%)*	*1,443 (8.5%)*	*36 (0.2%)*	*5 (0.1%)*	*191 (1.1%)*	*1,694 (10.0%)*	*88 (0.5%)*
Nebraska									
Keya Paha	1	264 (26.9%)	0 (0%)	0 (0%)	0 (0%)	0 (0%)	5 (0.5%)	5 (0.5%)	24 (2.4%)
Rock	1	217 (25.8%)	0 (0%)	7 (0.8%)	0 (0%)	0 (0%)	0 (0%)	7 (0.8%)	4 (0.5%)
Holt	2	318 (15.5%)	0 (0%)	24 (1.2%)	0 (0%)	5 (0.2%)	4 (0.2%)	33 (1.6%)	7 (0.3%)
Garfield	1	67 (10.9%)	0 (0%)	0 (0%)	2 (0.3%)	0 (0%)	0 (0%)	2 (0.3%)	7 (1.1%)
Wheeler	1	183 (20.7%)	2 (0.2%)	5 (0.6%)	0 (0%)	7 (0.8%)	2 (0.2%)	16 (0.2%)	7 (0.8%)
Greeley	2	387 (14.3%)	8 (0.3%)	0 (0%)	3 (0.1%)	14 (0.5%)	2 (0.1%)	27 (1.0%)	16 (0.6%)
Boone	2	194 (13.3%)	0 (0%)	0 (0%)	4 (0.3%)	0 (0%)	4 (0.3%)	8 (0.6%)	13 (0.9%)
Nance	1	118 (17.1%)	0 (0%)	0 (0%)	4 (0.6%)	0 (0%)	5 (0.7%)	9 (1.3%)	0 (0%)
Merrick	2	145 (7.1%)	4 (0.2%)	0 (0%)	0 (0%)	8 (0.4%)	6 (0.3%)	18 (0.9%)	17 (0.8%)
Hamilton	1	46 (4.4%)	4 (0.4%)	0 (0%)	0 (0%)	0 (0%)	0 (0%)	4 (0.4%)	0 (0%)
Polk	1	28 (3.8%)	0 (0%)	0 (0%)	0 (0%)	0 (0%)	0 (0%)	0 (0%)	0 (0%)
York	3	432 (9.2%)	50 (1.1%)	11 (0.2%)	0 (0%)	72 (1.5%)	21 (0.5%)	154 (3.3%)	100 (2.1%)
Fillmore	2	297 (10.8%)	0 (0%)	8 (0.3%)	7 (0.3%)	11 (0.4%)	35 (1.3%)	61 (2.3%)	15 (0.5%)
Saline	2	145 (7.9%)	2 (0.1%)	2 (0.1%)	2 (0.1%)	0 (0%)	9 (0.5%)	15 (0.8%)	4 (0.2%)
Jefferson	3	306 (8.2%)	0 (0%)	0 (0%)	8 (0.2%)	10 (0.3%)	46 (1.2%)	64 (1.7%)	25 (0.7%)
Subtotal Nebraska	*25*	*3,147 (11.6%)*	*70 (0.3%)*	*57 (0.2%)*	*30 (0.1%)*	*127 (0.5%)*	*139 (0.5%)*	*423 (1.6%)*	*239 (0.9%)*

TABLE 3.10.1-10
Minority and Low-Income Populations as Percentage of Census Block Group Populations in 4-Mile-Wide Analysis Area

County	Total Number of Census Block Groups	Low-Income	African American	Native American or Alaskan Native	Asian or Pacific Islander	Other	Two or More Races	Aggregate (Total) of Racial Minorities	Hispanic or Latino
New Cushing Extension Pump Stations									
Kansas									
Clay	4	456 (11.2%)	16 (0.4%)	7 (0.2%)	7 (0.2%)	7 (0.2%)	71 (1.7%)	108 (2.7%)	42 (1%)
Butler	1	37 (5.4%)	0 (0%)	5 (0.7%)	2 (0.3%)	0 (0%)	11 (1.6%)	18 (2.6%)	0 (0%)
Subtotal Kansas	*5*	*493 (10.3%)*	*16 (0.3%)*	*12 (0.3%)*	*9 (0.2%)*	*7 (0.1%)*	*82 (1.7%)*	*126 (2.6%)*	*42 (0.9%)*
Gulf Coast Segment									
Oklahoma									
Payne	2	322 (12.2%)	423 (16.0%)	102 (3.9%)	13 (0.5%)	24 (0.9%)	107 (4.0%)	669 (25.3%)	72 (2.7%)
Creek	2	312 (14.7%)	90 (4.3%)	202 (9.5%)	3 (0.1%)	6 (0.3%)	128 (6.0%)	429 (20.2%)	17 (0.8%)
Lincoln	6 (1)[a]	1,020 (16.0%)	108 (1.7%)	533 (8.3%)	14 (0.2%)	30 (0.5%)	258 (4.0%)	943 (14.7%)	48 (0.7%)
Okfuskee	5	795 (19.9%)	962 (24.0%)	451 (11.3%)	3 (0.1%)	16 (0.4%)	176 (4.4%)	1,608 (40.2%)	33 (0.8%)
Seminole	5	778 (18.8%)	326 (7.9%)	761 (18.4%)	2 (0.1%)	15 (0.3%)	211 (5.1%)	1,315 (31.8%)	46 (1.1%)
Hughes	9	1,992 (19.3%)	597 (5.8%)	1,631 (15.8%)	5 (0.1%)	73 (0.7%)	590 (5.7%)	2,896 (28.1%)	245 (2.4%)
Pontotoc	3	440 (14.4%)	13 (0.4%)	583 (19.0%)	3 (0.1%)	11 (0.4%)	171 (5.6%)	781 (25.5%)	26 (0.8%)
Coal	3	695 (20.6%)	20 (0.6%)	559 (16.6%)	7 (0.2%)	21 (0.6%)	170 (5.1%)	777 (23.1%)	63 (1.9%)
Atoka	6	1,091 (17.1%)	203 (3.2%)	825 (12.9%)	2 (0.1%)	13 (0.2%)	237 (3.7%)	1,280 (20.1%)	30 (0.5%)
Bryan	3	735 (18.8%)	10 (0.3%)	620 (15.9%)	5 (0.1%)	103 (2.6%)	121 (3.1%)	859 (22.0%)	136 (3.5%)
Choctaw	1	112 (16.5%)	0 (0%)	164 (24.1%)	0 (0%)	5 (0.8%)	43 (6.3%)	212 (31.2%)	27 (4.0%)
Subtotal Oklahoma	*45 (1)[a]*	*8,292 (17.6%)*	*2,752 (5.8%)*	*6,431 (13.7%)*	*57 (0.1%)*	*317 (0.7%)*	*2,212 (4.7%)*	*11,769 (25%)*	*743 (1.6%)*

TABLE 3.10.1-10
Minority and Low-Income Populations as Percentage of Census Block Group Populations in 4-Mile-Wide Analysis Area

County	Total Number of Census Block Groups	Low-Income	African American	Native American or Alaskan Native	Asian or Pacific Islander	Other	Two or More Races	Aggregate (Total) of Racial Minorities	Hispanic or Latino
Texas									
Fannin	2	173 (9.7%)	1,755 (98.1%)	0 (0%)	5 (0.3%)	0 (0%)	24 (1.3%)	5 (0.3%)	42 (2.3%)
Lamar	6	987 (15.0%)	361 (5.5%)	49 (0.7%)	8 (0.1%)	101 (1.6%)	98 (1.5%)	617 (9.4%)	236 (3.6%)
Delta	1	279 (18.5%)	9 (0.6%)	18 (1.2%)	16 (1.0%)	0 (0%)	45 (3.0%)	88 (5.8%)	0 (0%)
Hopkins	5	659 (13.2%)	70 (1.4%)	48 (1.0%)	0 (0%)	143 (2.9%)	47 (0.9%)	308 (6.2%)	387 (7.8%)
Franklin	3	482 (14.2%)	65 (1.9%)	20 (0.6%)	0 (0%)	204 (6.0%)	27 (0.8%)	316 (9.3%)	392 (11.5%)
Wood	8	1,374 (13.2%)	795 (7.7%)	24 (0.2%)	14 (0.1%)	89 (0.9%)	190 (1.8%)	1,112 (10.7%)	408 (4.0%)
Upshur	6	1,006 (13.9%)	550 (7.6%)	15 (0.2%)	11 (0.2%)	200 (2.7%)	61 (0.8%)	837 (11.5%)	244 (3.4%)
Smith	12	1,646 (10.3%)	3,920 (24.4%)	33 (0.2%)	9 (0.1%)	45 (0.3%)	108 (0.7%)	4,115 (25.7%)	504 (3.1%)
Rusk	4	877 (19.7%)	1,011 (22.7%)	24 (0.6%)	0 (0%)	270 (6.1%)	90 (2.0%)	1,395 (31.4%)	572 (12.9%)
Cherokee	5	1,201 (15.1%)	1,125 (14.1%)	48 (0.6%)	3 (0.1%)	506 (6.4%)	124 (1.5%)	1,806 (22.7%)	766 (9.6%)
Nacogdoches	5	972 (14.8%)	335 (5.1%)	15 (0.2%)	46 (0.7%)	381 (5.8%)	108 (1.6%)	885 (13.4%)	705 (10.7%)
Angelina	11 (1)[a]	2,986 (13.6%)	1,599 (7.3%)	59 (0.3%)	26 (0.1%)	2,032 (9.3%)	466 (2.1%)	4,182 (19.1%)	4,211 (19.2%)
Trinity	2	290 (17.4%)	263 (15.8%)	2 (0.1%)	0 (0%)	20 (1.2%)	12 (0.7%)	297 (17.8%)	27 (1.6%)
Polk	9	2,208 (15.0%)	1,025 (7.0%)	86 (0.6%)	35 (0.2%)	718 (4.9%)	227 (1.5%)	2,091 (14.2%)	1,449 (9.9%)
San Jacinto	1	393 (17.4%)	296 (13.1%)	0 (0%)	0 (0%)	45 (2.0%)	24 (1.0%)	365 (16.1%)	129 (5.7%)
Liberty	6	1,172 (20.1%)	314 (5.4%)	62 (1.0%)	27 (0.5%)	185 (3.2%)	91 (1.5%)	679 (11.6%)	363 (6.2%)
Hardin	5	852 (11.5%)	124 (1.7%)	34 (0.5%)	7 (0.1%)	85 (1.1%)	90 (1.2%)	340 (19.9%)	251 (3.4%)

TABLE 3.10.1-10
Minority and Low-Income Populations as Percentage of Census Block Group Populations in 4-Mile-Wide Analysis Area

County	Total Number of Census Block Groups	Low-Income	African American	Native American or Alaskan Native	Asian or Pacific Islander	Other	Two or More Races	Aggregate (Total) of Racial Minorities	Hispanic or Latino
Jefferson	43 (14)[a]	3,583 (5.7%)	10,697 (17%)	290 (0.5%)	1,026 (1.6%)	1,023 (1.6%)	790 (1.3%)	13,826 (22%)	5,978 (9.5%)
Orange	1	109 (4.8%)	0 (0%)	58 (2.6%)	0 (0%)	27 (1.2%)	43 (1.9%)	128 (5.7%)	84 (3.7%)
Subtotal Texas - Gulf Coast Segment	*135 (15)*[a]	*21,249 (11.2%)*	*22,559 (11.9%)*	*890 (0.5%)*	*1,228 (0.6%)*	*6,098 (3.2%)*	*2,646 (1.4%)*	*33,421 (17.6%)*	*16,748 (8.8%)*
Houston Lateral									
Liberty	17	2,700 (12.9%)	3,100 (14.8%)	60 (0.3%)	93 (0.4%)	868 (4.2%)	301 (1.4%)	4,422 (21.1%)	1,541 (7.4%)
Chambers	2	283 (6.8%)	72 (1.7%)	14 (0.4%)	0 (0%)	111 (2.7%)	38 (0.9%)	235 (5.7%)	243 (5.8%)
Harris	24	5,536 (11.0%)	11,317 (22.5%)	160 (0.3%)	1,134 (2.3%)	6,738 (13.4%)	1,326 (2.6%)	20,675 (41.1%)	13,643 (27.1%)
Subtotal Texas - Houston Lateral	*43 (2)*[a]	*8,519 (11.3%)*	*14,489 (19.2%)*	*234 (0.3%)*	*1,227 (1.7%)*	*7,717 (10.2%)*	*1,665 (2.2%)*	*25,332 (33.6%)*	*15,427 (20.5%)*
Subtotal Texas[b]	*174 (17)*[a]	*29,154 (11.2%)*	*36,770 (14.1%)*	*1,122 (0.4%)*	*2,428 (1.0%)*	*13,683 (5.2%)*	*4,238 (1.6%)*	*58,241 (22.3%)*	*31,912 (12.2%)*
Project Total	**287 (18)**	**46,549 (12.6%)**	**39,658 (10.7%)**	**9,747 (2.7%)**	**2,582 (0.7%)**	**14,164 (3.8%)**	**7,008 (1.9%)**	**73,159 (19.8%)**	**33,107 (9.0%)**

[a] Numbers in parentheses indicate number of census block groups fully contained within the 4-mile-wide analysis area.

[b] Four census block groups in Liberty County (CT 7006 BG 3, CT 7007 BG 1, CT 7013 BG 1, BG 3) affected by both the Gulf Coast Segment and Houston Lateral were only counted once in the Texas subtotal.

Sources: U.S. Census Bureau. 2002. Census Block Group SF3: 2000. Table P6 – Race. Table P7 – Hispanic or Latino by Race. Washington, D.C.
U.S. Census Bureau. 2002. Census Block Group SF3: 2000. Table P87 – Poverty Status in 1999 by Age. Washington, D.C.
See http://factfinder.census.gov/home.

Minority Populations

This section describes the minority populations along the proposed Project corridor using the methodology previously described.

Population within County

50 Percent Criterion

The percent of minority populations by county within the proposed Project area are listed in Table 3.10.1-9. The 2000 Census showed that no minority population exceeded 50 percent of the total county population in any county along the proposed Project route. Minority populations that were meaningfully greater than the corresponding minority population at the state level are identified with an asterisk (*) in the relevant racial/ethnic category columns in Table 3.10.1-9 and are also listed in Table 3.10.1-11. These minority populations were identified in 22 of the 59 counties in the proposed Project area.

Meaningfully Greater Criterion

Along the proposed Steele City Segment, eight counties had minority populations that were meaningfully greater than the corresponding state population. African American populations were identified in McCone County, Montana and Meade County, South Dakota. The Native American or Alaska Native population residing in Valley County, Montana, was partially located in the Fort Peck Indian Reservation, while the Lyman County, South Dakota population was partially located in the Lower Brule Indian Reservation. A Native American/Alaska Native population was also identified in Rock County, Nebraska. South Dakota counties also included populations of Asians or Pacific Islanders, "Other" races, people identifying themselves as multi-racial, people of Hispanic ethnic origin, and an aggregate minority population.

In Kansas, for the two new proposed pump stations, no counties had minority populations that were meaningfully greater than the corresponding state population.

Along the Gulf Coast Segment, 13 counties had minority populations that were meaningfully greater than the corresponding state population. Oklahoma had 7 counties with those minority populations, which were comprised of 6 counties with Native Americans or Alaska Natives (Okfuskee, Seminole, Hughes, Pontotoc, Coal, and Bryan counties) and Payne County had an Asian or Pacific Islander population. The remaining 6 county minority populations were in Texas, and included 3 counties with African Americans (Smith, Rusk, and Jefferson counties) and 3 counties with Native Americans or Alaska Natives (Fannin, Lamar, and Polk counties).

Along the Houston Lateral, Harris County had African American and Asian or Pacific Islander populations that were meaningfully greater than the corresponding state population.

Population within Census Block Groups

For each of the 287 census block groups located within the 4-mile-wide analysis area, the percentage of each census block group's population represented by each minority classification (each race, aggregate race minority population, and Hispanic/Latino ethnic origin) was calculated and compared to the 2 criteria described above. Tables 3.10.1-12 and 3.10.1-13 identify the minority populations that are represented graphically in Figures 3.10.1-1 through 3.10.1-6. These figures also identify towns and cities that occur

along the proposed pipeline corridor in relationship to the census block groups with minority and low-income populations meaningfully greater than state-wide averages.

50 Percent Criterion

Within the comparative geographic area, a total of 25 census block groups had individual racial minority populations or aggregate minority populations that exceeded the 50 percent criterion. Along the proposed Steele City Segment, one population in Valley County, Montana and another in Ziebach County, South Dakota exceeded 50 percent for Native Americans or Alaskan Natives. The Valley County population is part of the Fort Peck Indian Reservation and the Ziebach County population is part of the Cheyenne River Indian Reservation. No census block groups with minority populations exceeding 50 percent of the total population were identified in the Nebraska portion of the Steele City Segment or in Kansas for the pump stations.

The Oklahoma section of the proposed Gulf Coast Segment contained 1 African American population and 1 aggregate minority population in Okfuskee County. These populations were within Boley, a community with 1,126 (55 percent) African American residents in 2000. In Texas, along the proposed Gulf Coast Segment, there were 13 populations that met the 50 percent criterion. Of the 9 African American populations, 1 was in Wood County near Hawkins, 2 were in Smith County east of Tyler, 1 was in Angelina County at Diboll, and 5 were in Jefferson County in or near Beaumont. Aggregate minority populations comprising 50 percent or more of the population included two in Jefferson County near Beaumont and 1 in Rusk County west of Mount Enterprise. One Hispanic population was located in Diboll in Angelina County.

For the proposed Houston Lateral, Liberty County and Harris County each had two populations that met the 50 percent criterion for African Americans. The African American populations in Liberty County were located near Liberty, Ames, and Devers and in Harris County near Barrett. Four aggregate minority populations were in Harris County, near Cloverleaf and east of Houston.

Meaningfully Greater Criterion

Proposed Project Summary

There were 181 meaningfully greater minority populations that occurred within 136 individual census block groups (see Table 3.10.1-13) along the proposed Project analysis corridor. Of the 181 meaningfully greater minority populations, 24 were identified along the proposed Steele City Segment, none were found in proximity to the Kansas pump stations, 118 were identified along the proposed Gulf Coast Segment, and 41 were identified along the proposed Houston Lateral. One African American and multi-race population occurred in Liberty County, Texas in proximity to both the proposed Gulf Coast Segment and the proposed Houston Lateral.

Proposed Steele City Segment

For the proposed Steele City Segment, there were 10 meaningfully greater minority populations that occurred within 7 individual census block groups in Montana. Three African American populations were in Montana, 1 each in Valley County, McCone County (in Circle), and Fallon County (in Baker). Two Native American or Alaskan Native populations were in Valley County on the Fort Peck Indian Reservation. Two "Other" populations also were in Valley County, 1 in the Fort Peck Indian Reservation and 1 east of Glasgow. Multi-racial populations in Montana were identified in both Valley County and

McCone County. One aggregate minority population was also identified in Valley County, primarily comprised of Native Americans or Alaskan Natives.

South Dakota had 13 meaningfully greater minority populations that occurred within 9 individual census block groups. One African American population was identified in Harding County. One Native American or Alaskan Native population was in Ziebach County on the Cheyenne River Indian Reservation and 2 were in Tripp County within Winner. One Asian or Pacific Islander population was identified in both Haakon County and in Tripp County (at Winner). Multi-racial populations included 1 each in Jones and Lyman counties, and 3 in Tripp County. One Hispanic population also was located in Tripp County, near Winner. One aggregate minority population was identified in Ziebach County, primarily comprised of Native Americans or Alaskan Natives.

Nebraska had one multi-racial population in Jefferson County.

Proposed Gulf Coast Segment

For the proposed Gulf Coast Segment in Oklahoma, there were 41 meaningfully greater minority populations that occurred within 32 individual census block groups. African American populations were in Payne County (at Cushing), Lincoln County (at Stroud), Seminole County (at Cromwell), Hughes County (at Holdenville), and Atoka County (at Atoka). Two African American populations were in Okfuskee County (within Boley). Of the 25 Native American or Alaskan Native groups, 1 was in Choctaw County; 2 were in each of Okfuskee and Bryan counties; 3 were in each of Pontotoc and Coal counties; 4 were in each of Seminole and Atoka counties; and 6 populations were in Hughes County. One Asian or Pacific Islander population was in Lincoln County (near Stroud) and 1 "Other" population was identified in Bryan County. Individual multi-racial groups were in Seminole, Pontotoc, and Atoka counties; and 3 groups were in Hughes County. One aggregate minority population was also identified in Okfuskee County, primarily comprised of African American and Native American or Alaskan Native groups.

In Texas, there were 77 meaningfully greater minority populations that occurred within 64 individual census block groups. Of the 31 African American populations, 1 each was in Lamar, Cherokee, Angelina, Trinity, Polk, and Liberty counties; 2 were in Wood County (near Hawkins); 3 were in Rusk County (west of Mount Enterprise); 3 were in Smith County (east of Tyler), and 12 were in Jefferson County (near Beaumont). Native American or Alaskan Native populations included 1 each in Delta, Franklin, Upshur, Smith, Rusk, Nacogdoches, Angelina, Hardin, and Orange counties; 2 were identified in each of Lamar, Hopkins, Polk, and Liberty counties; and 10 populations were in Jefferson County. Four Asian or Pacific Islander populations were in Jefferson County (within Beaumont and Nederland). "Other" populations identified included 3 in Angelina County (within Diboll), and 1 in Polk County. Ten multi-race populations were identified, including 1 each in Lamar, Wood, Polk, and Liberty counties; 2 in Angelina County; and 4 in Jefferson County. A Hispanic population was located in Angelina County (near Diboll).

Proposed Houston Lateral

The proposed Houston Lateral contained 41 meaningfully greater minority populations that occurred within 24 individual census block groups. Six African American populations were identified in Liberty County (near Liberty, Devers, and Ames), and 9 were identified in Harris County (surrounding Barrett and Channelview). Of the 4 Native American or Alaskan Native populations identified, 1 was Liberty County and 3 were in Harris County (near Sheldon and Highlands). Three Asian or Pacific Islander populations were in Harris County (near Cloverleaf). Eight "Other" populations were identified in Harris County (within Channelview). Four multi-race populations were identified in Liberty County (near

TABLE 3.10.1-11 County-Level Minority Populations Meaningfully Greater than Corresponding States' Minority Population		
Minority Population	**County**	**State**
Steele City Segment		
African American	McCone	Montana
	Meade	South Dakota
Native American or Alaska Native	Valley	Montana
	Lyman	South Dakota
	Rock	Nebraska
Asian or Pacific Islander	Pennington	South Dakota
Other	Butte	South Dakota
	Meade	South Dakota
	Pennington	South Dakota
Two or More Races	Meade	South Dakota
	Pennington	South Dakota
	Jones	South Dakota
	Lyman	South Dakota
Aggregate of Racial Minorities	Lyman	South Dakota
Hispanic	Butte	South Dakota
	Pennington	South Dakota
Gulf Coast Segment		
African American	Smith	Texas
	Rusk	Texas
	Jefferson	Texas
Native American or Alaska Native	Okfuskee	Oklahoma
	Seminole	Oklahoma
	Hughes	Oklahoma
	Pontotoc	Oklahoma
	Coal	Oklahoma
	Bryan	Oklahoma
	Fannin	Texas
	Lamar	Texas
	Polk	Texas
Asian or Pacific Islander	Payne	Oklahoma
Houston Lateral		
African American	Harris	Texas
Asian or Pacific Islander	Harris	Texas

Sources: U.S. Census Bureau. 2002. Census Block Group SF3: 2000. Table P6 - Race. Table P7 – Hispanic or Latino by Race. Washington, D.C.

U.S. Census Bureau. 2002. Census Block Group SF3: 2000. Table P87 – Poverty Status in 1999 by Age. Washington, D.C.

Dayton and Devers), and 6 were identified in Harris County (surrounding Barrett and Channelview). One Hispanic population was along the proposed Houston Lateral in Harris County (within Channelview).

Low-Income Populations

Low-income populations in the region of influence were identified and evaluated using poverty data from the United States Census Bureau. As with minority populations, low-income populations were evaluated using the absolute 50 percent and the relative 150 percent greater criteria, first for counties and then for potentially affected census block groups within the counties. If the percentage of low-income individuals was 150 percent greater in a county than the corresponding state in which it was located, it was considered to be a low-income population. These counties are noted with an asterisk (*) in the far right column of Table 3.10.1-9. Also, low-income individuals in each census block group were divided by the total individuals for that census block group to obtain the percentage of low-income individuals per census block group. If any census block group percentage exceeded the corresponding state percentage by more than 150 percent, then the census block group was identified as containing a low-income population.

Four states, Montana (14.6 percent), South Dakota (13.2 percent), Oklahoma (14.7 percent), and Texas (15.4 percent) had greater rates of low-income residents in 1999 than the U.S. rate of 12.4 percent. In comparison, 9.9 percent of Kansas residents were considered low-income in 1999 and 9.7 percent of Nebraska residents were considered low-income, noticeably less than for the United States percentage. Thus, for comparative purposes, the 150-percent exceedance criterion for each state would be 21.9 percent for Montana, 19.8 percent for South Dakota, 14.6 percent for Nebraska, 14.9 percent for Kansas, 22.1 percent for Oklahoma, and 23.1 percent for Texas.

Population within County

As shown in Table 3.10.1-9, no counties had 50 percent or more of low-come individuals. In total, 6 of the 59 counties that comprise the proposed Project area met the 150 percent meaningfully greater criterion for low-income populations.

In the proposed Steele City Segment, 5 out of 29 counties had meaningfully greater low-income populations, including Harding and Lyman counties in South Dakota and Keya Paha, Rock, and Wheeler counties in Nebraska. None of the counties in Kansas were classified as low-income. In the proposed Gulf Coast Segment, only Coal County, Oklahoma had a meaningfully greater low-income population. None of the other 27 counties in the proposed Gulf Coast Segment met the meaningfully greater criteria of 22.1 percent in Oklahoma or 23.1 percent in Texas. The 3 counties along the proposed Houston Lateral also did not have low-income populations.

Population within Census Block Groups

Populations within census block groups meeting either of the absolute 50 percent or 150 percent meaningfully greater criteria are described in this section. Of the 287 census block groups assessed along the proposed Project analysis corridor, 48 contained low-income populations. Tables 3.10.1-12 and 3.10.1-13 and Figures 3.10.1-1 through 3.10.1-6 identify these low-income populations within census block groups.

50 Percent Criterion

Only 1 low-income population within census block groups along the 4-mile-wide analysis corridor exceeded the 50 percent criterion. This population also exceeded the 150-percent criterion as described in the following section. The population was located in Ziebach County, South Dakota on part of the Cheyenne River Indian Reservation.

Meaningfully Greater Criterion

A total of 48 populations within individual census block groups along the 4-mile-wide analysis corridor had 150 percent more than the percentage of low-income individuals for each corresponding state. Table 3.10.1-13 indicates that of these 48 low-income populations, 18 were located along the Steele City Segment, 1 was at the pump stations in Kansas, 26 were along the Gulf Coast Segment, and 4 were along the Houston Lateral. One low-income population was identified in Liberty County, Texas for both the Gulf Coast Segment and the Houston Lateral.

For Montana, 1 low-income population was in each for Phillips, Valley, and Prairie counties. Of the 9 low-income populations in South Dakota, 1 was in each of Harding, Perkins, Ziebach, and Gregory counties; and 5 were in Tripp County surrounding Winner. Tripp County had the most low-income populations identified in any state affected by the proposed Project. Nebraska contained 6 low-income populations, 1 was in each of Keya Paha, Rock, Wheeler, and Nance counties; and 2 were in Holt County.

At the proposed Pump Station 29 in Kansas, 1 low-income population was identified near Clay Center.

In the Gulf Coast Segment, of the 14 low-income populations in Oklahoma, 1 was in each of Payne, Seminole, Pontotoc, and Coal counties; 2 were in each of Lincoln and Bryan counties; and 3 were in each of Okfuskee and Hughes counties. The Gulf Coast Segment in Texas contained 12 low-income populations, 1 was in each of Lamar, Hopkins, Wood, Rusk, Cherokee, Nacogdoches, Angelina, Polk, Hardin, and Jefferson counties; and 2 were in Liberty County.

For the Houston Lateral in Texas, 3 low-income populations were in Liberty County and 1 was in Harris County.

TABLE 3.10.1-12
Number of Minority and Low-Income Populations Exceeding 50% within Census Block Groups by County in 4-Mile-Wide Analysis Area

County	Total Number of Census Block Groups Assessed	Census Block Groups Containing Low-Income Populations	Census Block Groups Containing One or More Minority Populations	Minority Populations							
				African American	Native American or Alaskan Native	Asian or Pacific Islander	Other	Two or More Races	Aggregate (Total) of Racial Minorities	Hispanic or Latino	Total Number of Minority Populations
Steele City Segment											
Montana											
Phillips	1	0	0	0	0	0	0	0	0	0	0
Valley	6	0	1	0	1	0	0	0	0	0	1
McCone	3	0	0	0	0	0	0	0	0	0	0
Dawson	2	0	0	0	0	0	0	0	0	0	0
Prairie	1	0	0	0	0	0	0	0	0	0	0
Fallon	3	0	0	0	0	0	0	0	0	0	0
Carter	1	0	0	0	0	0	0	0	0	0	0
Subtotal Montana	*17*	*0*	*1*	*0*	*1*	*0*	*0*	*0*	*0*	*0*	1
South Dakota											
Harding	2	0	0	0	0	0	0	0	0	0	0
Butte	1	0	0	0	0	0	0	0	0	0	0
Perkins	1	0	0	0	0	0	0	0	0	0	0
Meade	2	0	0	0	0	0	0	0	0	0	0
Ziebach	1	1	1	0	1	0	0	0	0	0	1
Pennington	1	0	0	0	0	0	0	0	0	0	0
Haakon	2	0	0	0	0	0	0	0	0	0	0
Jones	1	0	0	0	0	0	0	0	0	0	0
Lyman	1	0	0	0	0	0	0	0	0	0	0

TABLE 3.10.1-12
Number of Minority and Low-Income Populations Exceeding 50% within Census Block Groups by County in 4-Mile-Wide Analysis Area

County	Total Number of Census Block Groups Assessed	Census Block Groups Containing Low-Income Populations	Census Block Groups Containing One or More Minority Populations	Minority Populations							
				African American	Native American or Alaskan Native	Asian or Pacific Islander	Other	Two or More Races	Aggregate (Total) of Racial Minorities	Hispanic or Latino	Total Number of Minority Populations
Tripp	8	0	0	0	0	0	0	0	0	0	0
Gregory	1	0	0	0	0	0	0	0	0	0	0
Subtotal South Dakota	*21*	*1*	*1*	*0*	*1*	*0*	*0*	*0*	*0*	*0*	1
Nebraska											
Keya Paha	1	0	0	0	0	0	0	0	0	0	0
Rock	1	0	0	0	0	0	0	0	0	0	0
Holt	2	0	0	0	0	0	0	0	0	0	0
Garfield	1	0	0	0	0	0	0	0	0	0	0
Wheeler	1	0	0	0	0	0	0	0	0	0	0
Greeley	2	0	0	0	0	0	0	0	0	0	0
Boone	2	0	0	0	0	0	0	0	0	0	0
Nance	1	0	0	0	0	0	0	0	0	0	0
Merrick	2	0	0	0	0	0	0	0	0	0	0
Hamilton	1	0	0	0	0	0	0	0	0	0	0
Polk	1	0	0	0	0	0	0	0	0	0	0
York	3	0	0	0	0	0	0	0	0	0	0
Fillmore	2	0	0	0	0	0	0	0	0	0	0
Saline	2	0	0	0	0	0	0	0	0	0	0
Jefferson	3	0	0	0	0	0	0	0	0	0	0
Subtotal Nebraska	*25*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	0

TABLE 3.10.1-12
Number of Minority and Low-Income Populations Exceeding 50% within Census Block Groups by County in 4-Mile-Wide Analysis Area

County	Total Number of Census Block Groups Assessed	Census Block Groups Containing Low-Income Populations	Census Block Groups Containing One or More Minority Populations	Minority Populations							
				African American	Native American or Alaskan Native	Asian or Pacific Islander	Other	Two or More Races	Aggregate (Total) of Racial Minorities	Hispanic or Latino	Total Number of Minority Populations
New Pump Stations – Kansas											
Clay	4	0	0	0	0	0	0	0	0	0	0
Butler	1	0	0	0	0	0	0	0	0	0	0
Subtotal Kansas	*5*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	0
Gulf Coast Segment											
Oklahoma											
Payne	2	0	0	0	0	0	0	0	0	0	0
Creek	2	0	0	0	0	0	0	0	0	0	0
Lincoln	6 (1)[a]	0	0	0	0	0	0	0	0	0	0
Okfuskee	5	0	2	1	0	0	0	0	1	0	2
Seminole	5	0	0	0	0	0	0	0	0	0	0
Hughes	9	0	0	0	0	0	0	0	0	0	0
Pontotoc	3	0	0	0	0	0	0	0	0	0	0
Coal	3	0	0	0	0	0	0	0	0	0	0
Atoka	6	0	0	0	0	0	0	0	0	0	0
Bryan	3	0	0	0	0	0	0	0	0	0	0
Choctaw	1	0	0	0	0	0	0	0	0	0	0
Subtotal Oklahoma	*45 (1)[a]*	*0*	*2*	*1*	*0*	*0*	*0*	*0*	*1*	*0*	*2*
Texas											
Fannin	2	0	0	0	0	0	0	0	0	0	0
Lamar	6	0	0	0	0	0	0	0	0	0	0

TABLE 3.10.1-12
Number of Minority and Low-Income Populations Exceeding 50% within Census Block Groups by County in 4-Mile-Wide Analysis Area

County	Total Number of Census Block Groups Assessed	Census Block Groups Containing Low-Income Populations	Census Block Groups Containing One or More Minority Populations	Minority Populations							
				African American	Native American or Alaskan Native	Asian or Pacific Islander	Other	Two or More Races	Aggregate (Total) of Racial Minorities	Hispanic or Latino	Total Number of Minority Populations
Delta	1	0	0	0	0	0	0	0	0	0	0
Hopkins	5	0	0	0	0	0	0	0	0	0	0
Franklin	3	0	0	0	0	0	0	0	0	0	0
Wood	8	0	1	1	0	0	0	0	0	0	1
Upshur	6	0	0	0	0	0	0	0	0	0	0
Smith	12	0	2	2	0	0	0	0	0	0	2
Rusk	4	0	1	0	0	0	0	0	1	0	1
Cherokee	5	0	0	0	0	0	0	0	0	0	0
Nacogdoches	5	0	0	0	0	0	0	0	0	0	0
Angelina	11 (1)[a]	0	2	1	0	0	0	0	0	1	2
Trinity	2	0	0	0	0	0	0	0	0	0	0
Polk	9	0	0	0	0	0	0	0	0	0	0
Hardin	5	0	0	0	0	0	0	0	0	0	0
Jefferson	43 (14)[a]	0	7	5	0	0	0	0	2	0	7
Orange	1	0	0	0	0	0	0	0	0	0	0
Subtotal Texas - Gulf Coast Segment	*135 (15)[a]*	*0*	*13*	*9*	*0*	*0*	*0*	*0*	*3*	*1*	*13*
Houston Lateral											
Liberty	17	0	2	2	0	0	0	0	0	0	2
Chambers	2	0	0	0	0	0	0	0	0	0	0
Harris	24	0	6	2	0	0	0	0	4	0	6

TABLE 3.10.1-12
Number of Minority and Low-Income Populations Exceeding 50% within Census Block Groups by County in 4-Mile-Wide Analysis Area

County	Total Number of Census Block Groups Assessed	Census Block Groups Containing Low-Income Populations	Census Block Groups Containing One or More Minority Populations	Minority Populations							
				African American	Native American or Alaskan Native	Asian or Pacific Islander	Other	Two or More Races	Aggregate (Total) of Racial Minorities	Hispanic or Latino	Total Number of Minority Populations
Subtotal Texas - Houston Latera)	*43 (2)*[a]	*0*	8	*4*	*0*	*0*	*0*	*0*	*4*	*0*	8
Subtotal Texas[b]	*174 (17)*[a]	*0*	21	*13*	*0*	*0*	*0*	*0*	*7*	*1*	*21*
Project Total	**287 (18)**[a]	**1**	**25**	**14**	**2**	**0**	**0**	**0**	**8**	**1**	**25**

[a] Numbers in parentheses indicate number of census block groups fully contained within the 4-mile-wide analysis area.

[b] Four census block groups in Liberty County (CT 7006 BG 3, CT 7007 BG 1, CT 7013 BG 1, BG 3) affected by both the Gulf Coast Segment and Houston Lateral were only counted once in the Texas subtotal.

Sources: U.S. Census Bureau. 2002. Census Block Group SF3: 2000. Table P6 – Race. Table P7 – Hispanic or Latino by Race. Washington, D.C.

U.S. Census Bureau. 2002. Census Block Group SF3: 2000. Table P87 – Poverty Status in 1999 by Age. Washington, D.C.
See http://factfinder.census.gov/home

TABLE 3.10.1-13
Minority and Low-Income (Environmental Justice) Populations Exceeding 150% of State Levels within Census Block Groups by County in 4-Mile-Wide Analysis Area

County	Total Number of Census Block Groups Assessed	Census Block Groups Containing Low-Income Populations	Census Block Groups Containing One or More Minority Populations	Minority Populations							
				African American	Native American or Alaskan Native	Asian or Pacific Islander	Other	Two or More Races	Aggregate (Total) of Racial Minorities	Hispanic or Latino	Total Number of Minority Populations
Steele City Segment											
Montana											
Phillips	1	1	0	0	0	0	0	0	0	0	0
Valley	6	1	4	1	2	0	2	1	1	0	7
McCone	3	0	2	1	0	0	0	1	0	0	2
Dawson	2	0	0	0	0	0	0	0	0	0	0
Prairie	1	1	0	0	0	0	0	0	0	0	0
Fallon	3	0	1	1	0	0	0	0	0	0	1
Carter	1	0	0	0	0	0	0	0	0	0	0
Subtotal Montana	*17*	*3*	*7*	*3*	*2*	*0*	*2*	*2*	*1*	*0*	10
Montana Exceedance Criteria[a]	-	21.9%	-	0.5%	9.3%	0.9%	0.9%	2.6%	14.2%	3.0%	-
South Dakota											
Harding	2	1	1	1	0	0	0	0	0	0	1
Butte	1	0	0	0	0	0	0	0	0	0	0
Perkins	1	1	0	0	0	0	0	0	0	0	0
Meade	2	0	0	0	0	0	0	0	0	0	0
Ziebach	1	1	1	0	1	0	0	0	1	0	2
Pennington	1	0	0	0	0	0	0	0	0	0	0
Haakon	2	0	1	0	0	1	0	0	0	0	1
Jones	1	0	1	0	0	0	0	1	0	0	1

TABLE 3.10.1-13
Minority and Low-Income (Environmental Justice) Populations Exceeding 150% of State Levels within Census Block Groups by County in 4-Mile-Wide Analysis Area

County	Total Number of Census Block Groups Assessed	Census Block Groups Containing Low-Income Populations	Census Block Groups Containing One or More Minority Populations	Minority Populations							
				African American	Native American or Alaskan Native	Asian or Pacific Islander	Other	Two or More Races	Aggregate (Total) of Racial Minorities	Hispanic or Latino	Total Number of Minority Populations
Lyman	1	0	1	0	0	0	0	1	0	0	1
Tripp	8	5	4	0	2	1	0	3	0	1	7
Gregory	1	1	0	0	0	0	0	0	0	0	0
Subtotal South Dakota	*21*	*9*	*9*	*1*	*3*	*2*	*0*	*5*	*1*	*1*	13
South Dakota Exceedance Criteria[a]	-	19.8%	-	0.9%	12.5%	0.9%	0.8%	2.0%	17.0%	2.1%	-
Nebraska											
Keya Paha	1	1	0	0	0	0	0	0	0	0	0
Rock	1	1	0	0	0	0	0	0	0	0	0
Holt	2	2	0	0	0	0	0	0	0	0	0
Garfield	1	0	0	0	0	0	0	0	0	0	0
Wheeler	1	1	0	0	0	0	0	0	0	0	0
Greeley	2	0	0	0	0	0	0	0	0	0	0
Boone	2	0	0	0	0	0	0	0	0	0	0
Nance	1	1	0	0	0	0	0	0	0	0	0
Merrick	2	0	0	0	0	0	0	0	0	0	0
Hamilton	1	0	0	0	0	0	0	0	0	0	0
Polk	1	0	0	0	0	0	0	0	0	0	0
York	3	0	0	0	0	0	0	0	0	0	0
Fillmore	2	0	0	0	0	0	0	0	0	0	0

TABLE 3.10.1-13
Minority and Low-Income (Environmental Justice) Populations Exceeding 150% of State Levels within Census Block Groups by County in 4-Mile-Wide Analysis Area

County	Total Number of Census Block Groups Assessed	Census Block Groups Containing Low-Income Populations	Census Block Groups Containing One or More Minority Populations	Minority Populations							
				African American	Native American or Alaskan Native	Asian or Pacific Islander	Other	Two or More Races	Aggregate (Total) of Racial Minorities	Hispanic or Latino	Total Number of Minority Populations
Saline	2	0	0	0	0	0	0	0	0	0	0
Jefferson	3	0	1	0	0	0	0	1	0	0	1
Subtotal Nebraska	*25*	*6*	*1*	*0*	*0*	*0*	*0*	*1*	*0*	*0*	1
Nebraska Exceedance Criteria[a]	-	14.6%	-	6.0%	1.4%	1.9%	4.2%	2.1%	15.6%	8.25%	-
New Pump Stations – Kansas											
Clay	4	1	0	0	0	0	0	0	0	0	0
Butler	1	0	0	0	0	0	0	0	0	0	0
Subtotal Kansas	*5*	*1*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	0
Kansas Exceedance Criteria[a]	-	14.9%	-	8.6%	1.4%	2.6%	5.2%	3.2%	20.8%	10.5%	-
Gulf Coast Segment											
Oklahoma											
Payne	2	1	1	1	0	0	0	0	0	0	1
Creek	2	0	0	0	0	0	0	0	0	0	0
Lincoln	6 (1)[b]	2(1)[b]	1	1	0	1	0	0	0	0	2
Okfuskee	5	3	4	2	2	0	0	0	1	0	5
Seminole	5	1	4	1	4	0	0	1	0	0	6
Hughes	9	3	8	1	6	0	0	3	0	0	10
Pontotoc	3	1	3	0	3	0	0	1	0	0	4

TABLE 3.10.1-13
Minority and Low-Income (Environmental Justice) Populations Exceeding 150% of State Levels within Census Block Groups by County in 4-Mile-Wide Analysis Area

County	Total Number of Census Block Groups Assessed	Census Block Groups Containing Low-Income Populations	Census Block Groups Containing One or More Minority Populations	Minority Populations							
				African American	Native American or Alaskan Native	Asian or Pacific Islander	Other	Two or More Races	Aggregate (Total) of Racial Minorities	Hispanic or Latino	Total Number of Minority Populations
Coal	3	1	3	0	3	0	0	0	0	0	3
Atoka	6	0	4	1	4	0	0	1	0	0	6
Bryan	3	2	3	0	2	0	1	0	0	0	3
Choctaw	1	0	1	0	1	0	0	0	0	0	1
Subtotal Oklahoma	*45 (1)*[b]	*14* (1)[b]	*32*	*7*	*25*	*1*	*1*	*6*	*1*	*0*	41
Oklahoma Exceedance Criteria[a]	-	22.1%	-	11.4%	11.9%	2.0%	3.6%	7.0%	35.6%	7.8%	-
Texas											
Fannin	2	0	0	0	0	0	0	0	0	0	0
Lamar	6	1	3	1	2	0	0	1	0	0	4
Delta	1	0	1	0	1	0	0	0	0	0	1
Hopkins	5	1	2	0	2	0	0	0	0	0	2
Franklin	3	0	1	0	1	0	0	0	0	0	1
Wood	8	1	3	2	0	0	0	1	0	0	3
Upshur	6	0	1	0	1	0	0	0	0	0	1
Smith	12	0	8	8	1	0	0	0	0	0	9
Rusk	4	1	4	3	1	0	0	0	0	0	4
Cherokee	5	1	1	1	0	0	0	0	0	0	1
Nacogdoches	5	1	1	0	1	0	0	0	0	0	1
Angelina	11 (1)[b]	1 (1)[b]	7 (1)[b]	1	1	0	3	2	0	1	8
Trinity	2	0	1	1	0	0	0	0	0	0	1

TABLE 3.10.1-13
Minority and Low-Income (Environmental Justice) Populations Exceeding 150% of State Levels within Census Block Groups by County in 4-Mile-Wide Analysis Area

County	Total Number of Census Block Groups Assessed	Census Block Groups Containing Low-Income Populations	Census Block Groups Containing One or More Minority Populations	Minority Populations							
				African American	Native American or Alaskan Native	Asian or Pacific Islander	Other	Two or More Races	Aggregate (Total) of Racial Minorities	Hispanic or Latino	Total Number of Minority Populations
Polk	9	1	5	1	2	0	1	1	0	0	5
San Jacinto	1	0	0	0	0	0	0	0	0	0	0
Liberty	6	2	3	1	2	0	0	1	0	0	4
Hardin	5	1	1	0	1	0	0	0	0	0	1
Jefferson	43 (14)[b]	1	21 (7)[b]	12	10	4	0	4	0	0	30
Orange	1	0	1	0	1	0	0	0	0	0	1
Subtotal Texas - Gulf Coast Segment	*135 (15)[b]*	*12* (1)[b]	*64 (8)[b]*	*31*	*27*	*4*	*4*	*10*	*0*	*1*	77
Texas Exceedance Criteria[a]	-	23.1%	-	17.3%	0.9%	4.2%	17.6%	3.8%	43.7%	48.0%	-
Houston Lateral											
Liberty	17	3	8	6	1	0	0	4	0	0	11
Chambers	2	0	0	0	0	0	0	0	0	0	0
Harris	24	1	16 (1)[b]	9	3	3	8	6	0	1	30
Subtotal Texas - Houston Latera)	*43 (2)[b]*	*4*	24 (1)[b]	*15*	*4*	*3*	*8*	*10*	*0*	*1*	41
Texas Exceedance Criteria[a]	-	23.1%	-	17.3%	0.9%	4.2%	17.6%	3.8%	43.7%	48.0%	-
Subtotal Texas[c]	*174 (17)[b]*	*15* (1)[b]	87 (9)[b]	*45*	*31*	*7*	*12*	*19*	*0*	*2*	*116*

TABLE 3.10.1-13
Minority and Low-Income (Environmental Justice) Populations Exceeding 150% of State Levels within Census Block Groups by County in 4-Mile-Wide Analysis Area

County	Total Number of Census Block Groups Assessed	Census Block Groups Containing Low-Income Populations	Census Block Groups Containing One or More Minority Populations	Minority Populations							
				African American	Native American or Alaskan Native	Asian or Pacific Islander	Other	Two or More Races	Aggregate (Total) of Racial Minorities	Hispanic or Latino	Total Number of Minority Populations
Project Total	**287 (18)[b]**	**48 (2)[b]**	**136 (9)[b]**	**56**	**61**	**10**	**15**	**33**	**3**	**3**	**181**

[a] State-wide exceedance criteria percentages are 1.5 times the actual Environmental Justice group population percentages for each state.

[b] Numbers in parentheses indicate number of census block groups fully contained within the 4-mile-wide analysis area.

[c] Four census block groups in Liberty County (CT 7006 BG 3, CT 7007 BG 1, CT 7013 BG 1, BG 3) affected by both the Gulf Coast Segment and Houston Lateral were only counted once in the Texas subtotal.

Sources: U.S. Census Bureau. 2002. Census Block Group SF3: 2000. Table P6 – Race. Table P7 – Hispanic or Latino by Race. Washington, D.C.

U.S. Census Bureau. 2002. Census Block Group SF3: 2000. Table P87 – Poverty Status in 1999 by Age. Washington, D.C.

See http://factfinder.census.gov/home.

3.10.1.2 Potential Impacts

This was Section 3.10.2 in the draft EIS. There have been no substantive changes to this section and therefore it is not included in the SDEIS. The draft EIS subsection can be downloaded at www.keystonepipeline-xl.state.gov

Construction Impacts

This was Section 3.10.2.3 in the draft EIS. Except for the subsection on environmental justice, there have been no substantive changes to this section and therefore it is not included in the SDEIS. The draft EIS subsection can be downloaded at www.keystonepipeline-xl.state.gov.

Environmental Justice

As described in Section 3.10.1.1, portions of the proposed pipeline and proposed pump stations are in areas with minority and low-income populations. Populations of concern from an environmental justice perspective were assessed at both a county and census block group level.

Minority and Low-Income Populations within Counties

The proposed Project would not cross within 2 miles of counties that had greater than 50 percent of the state-wide average for minority or low-income populations at the time of census data collection. However, 22 of the 59 counties (37 percent) were identified as having a meaningfully greater minority population than the state-wide average and 6 counties (10 percent) were identified as having a meaningfully greater low-income population than the state-wide average.

Table 3.10.1-16 provides a list of the counties within the proposed Project area and specifies:

- Whether a pipe yard (PY), a construction camp (CY), a contractors camp (CC), or a railroad siding facility (RRS/PY) is planned to be located within that county;
- Whether there is at least one minority population meaningfully greater than the overall state minority population in that county; and
- Whether the number of low-income individuals in that county is meaningfully greater than the state average.

These types of facilities are planned in 33 counties within the proposed Project area and 13 of those counties (39 percent) have one or more environmental justice percentages meaningfully greater than the state-wide averages.

These data suggest that potential impacts to minority and low-income populations during construction within counties crossed by the proposed Project corridor would be minor and would not disproportionately affect these populations when considered at the county population level.

TABLE 3.10.1-16 Location of Construction Facilities Relative to County Environmental Justice Statistics			
		Statistic Meaningfully Greater than Respective State (2000)	
County	Construction Facility[a]	Minority Population	Low-Income
Steele City Segment			
Montana			
Phillips	PY	No	No
Valley	2 PY, 1 CY, 1 CC	Yes	No
McCone	2 PY, 1 CY	Yes	No
Dawson	2 PY, 1 CY	No	No
Prairie	No	No	No
Fallon	2 PY, 1 CC	No	No
South Dakota			
Hardin	3 PY, 1 CY	No	Yes
Butte	No	Yes	No
Perkins	No	No	No
Meade	2 PY, 1 CY, 1 CC	Yes	No
Pennington	No	Yes	No
Haakon	2 PY, 1 CY	No	No
Jones	2 PY, 1 CY	Yes	No
Lyman	No	Yes	Yes
Tripp	2 PY, 1 CY, 1 CC	No	No
Nebraska			
Keya Paha	1 PY	No	Yes
Rock	No	Yes	Yes
Holt	2 PY, 2 CY	No	No
Garfield	No	No	No
Wheeler	No	No	Yes
Greeley	1 PY, 1 CY	No	No
Boone	No	No	No
Nance	1 PY	No	No
Merrick	1 CY	No	No
Hamilton	1 PY	No	No
York	1 CY	No	No
Fillmore	1 PY	No	No
Saline	No	No	No
Jefferson	1 PY, 1 CY	No	No
New Cushing Extension Pump Stations			
Kansas			
Clay	No	No	No

TABLE 3.10.1-16 Location of Construction Facilities Relative to County Environmental Justice Statistics			
		Statistic Meaningfully Greater than Respective State (2000)	
County	Construction Facility[a]	Minority Population	Low-Income
Butler	No	No	No
Gulf Coast Segment			
Oklahoma			
Payne	No	Yes	No
Creek	No	No	No
Lincoln	1 PY, 1 CY	No	No
Okfuskee	No	Yes	No
Seminole	No	Yes	No
Hughes	1 PY, 1 CY, 1 PY/RS	Yes	No
Pontotoc	No	Yes	No
Coal	No	Yes	Yes
Atoka	No	No	No
Bryan	1 PY, 1 CY	Yes	No
Texas			
Fannin	1 PY/RS	Yes	No
Lamar	1 PY, 1 CY, 1 RS, 1 PY/CY	Yes	No
Delta	No	No	No
Hopkins	No	No	No
Franklin	1 RS	No	No
Wood	No	No	No
Upshur	No	No	No
Smith	No	Yes	No
Rusk	1 CY	Yes	No
Cherokee	1 CY	No	No
Nacogdoches	1 CY	No	No
Angelina	1 CY, 1 RS, 1 PY/CY	No	No
Polk	2 PY	Yes	No
Liberty	1 CY	No	No
Hardin	1 RS	No	No
Jefferson	1 PY	Yes	No
Houston Lateral			
Liberty	1 CY	No	No
Chambers	No	No	No
Harris	No	Yes	No

[a] Abbreviations: Pipe Yard (PY), Construction Camp (CC) and Contractor Yards (CY) Railroad Siding and or a Pipe Yard (RRS/PY).

Minority and Low-Income Populations within Census Block Groups

A total of 287 census block groups were assessed along the 4-mile-wide analysis corridor. Within these census block groups, 181 minority populations that were meaningfully greater than the state-wide average were identified, and 48 low-income populations that were meaningfully greater than the state-wide average were also identified. Of the 287 total census block groups occurring along the proposed Project corridor, 129 census block groups had no exceedances for any minority or low-income populations. Of the 158 census block groups that did show exceedances, 136 showed exceedances for one or more minority populations, 22 showed exceedances for only low-income populations, and 26 showed exceedances for 1 or more minority populations along with a low-income population.

These data suggest that potential impacts to the minority and low-income populations identified in this assessment within the 4-mile wide analysis area could occur. The analysis of minority and low-income populations along the proposed Project corridor, as previously stated, is inherently conservative since 269 of the census block groups analyzed were only partially within the analysis area and it is therefore likely that the percentages of minority and low-income populations that actually occur within the 4-mile-wide analysis area are less than the percentages derived from the analysis. Only 18 of the census block groups analyzed fall entirely within the 4-mile-wide analysis area. These 18 census block groups occur for the most part in Harris, Jefferson, and Angelina Counties in Texas (17 census block groups), and of these census block groups occurs in Lincoln County, Oklahoma. These 18 census block groups occur within more populated areas along the proposed pipeline corridor. Of these, 9 census block groups show 1 or more minority or low-income populations greater than the respective state-wide averages (see Table 3.10.1-17).

TABLE 3.10.1-17
Census Block Groups Completely Contained within 4-Mile-Wide Analysis Area

Total Number of Census Block Groups	County, State	Nearest City or Town	Meaningfully Greater Minority Census Block Groups	Meaningfully Greater Low-Income Census Block Groups	Total Number of Census Block Groups Containing One or More EJ Group Exceedance*
1	Lincoln County, OK	Stroud	-	Yes	1
1	Angelina County, TX	Diboll	African American	Yes	1
1	Jefferson County, TX	Beaumont	African American	-	1
2	Jefferson County, TX	Port Neches	-	-	0
7	Jefferson County, TX	Nederland	Native American or Alaskan Native	-	2
2	Jefferson County, TX	Central Gardens	Native American or Alaskan Native	-	1
2	Jefferson County, TX	Beaumont and Central Gardens	African American; Native American or Alaskan Native; Two or More Races	-	2
1	Harris County, TX	Channelview	African American; Other	-	1
1	Harris County, TX	Highlands	-	-	0
18					**9**

* Exceedance criteria are 1.5 times the actual environmental justice (EJ) minority or low-income group population for each state.
Sources: U.S. Census Bureau. 2002. Census Block Group SF3: 2000. Table P6 – Race. Table P7 – Hispanic or Latino by Race. U.S. Census Bureau. 2002. Census Block Group SF3: 2000. Table P87 – Poverty Status in 1999 by Age. See http://factfinder.census.gov/home.

Impacts to minority and low-income populations during construction would include exposure to construction dust and noise, potential disruption to traffic patterns, and increased competition for social services in underserved populations. Construction dust and noise would be restricted to working hours during the construction period along each segment of the proposed Project route and impacts would diminish once construction activities end. At any given location along the proposed pipeline route, the duration of the construction period would typically range between 20 and 30 working days.

To assess the potential impact on minority and low-income populations in areas that could be underserved by health professionals, available medical facilities, or other health services, the minority and low-income populations identified in this analysis were compared to locations along the proposed Project corridor that are listed on the Health and Human Services (HHS) Health Resource Services Administration (HRSA) website. Areas designated as Health Professional Shortage Areas (HPSA) and Medically Underserved Areas/Populations (MUA/P) in counties that contain census block groups with one or more minority and/or low-income population identified in this assessment are presented Table 3.10.1-18 and Figures 3.10.1-7 through 3.10-1-13.

Based on these data, any additional disruptions to medical service availability in areas with minority or low-income populations that are designated as either HPSA and/or MUA/P areas could lead to short-term impacts to these populations during the construction period. However, in areas in Montana and South Dakota where construction camps would be provided, minor medical needs of workers would be handled in these camps, thus reducing the potential need for medical services from the surrounding communities. In any case, given the transient nature of the workforce, the impact of increased demand for medical services on local minority and low-income populations would be minor and short-term.

It is expected that there would be no impact to medical service availability in areas with minority or low-income populations that are designated as either HPSA and/or MUA/P areas during normal operation of the proposed Project due to the very small number of permanent employees along the proposed Project alignment. Potential impacts to minority and low-income populations resulting from an accidental release of crude oil from the proposed Project are addressed in Section 3.13.6.7.

TABLE 3.10.1-18
Designated HPSAs and MUA/Ps with Identified Minority and/or Low-Income Populations within Census Block Groups in Affected Counties along the Proposed Project Corridor

County	Total Number of Census Block Groups Assessed	Census Block Groups Containing One or More Identified Minority and/or Low-Income Population[a]	HPSA[b]		MUA/P[cd]	
			Designation Name / Facility Address	Geographic Area or Facility Type	Designation Name	Geographic Area
Steele City Segment						
Montana						
Phillips	1	1	Eastern Montana	County	Phillips Service Area	County
Valley	6	4	Eastern Montana	County	Valley Service Area	County
McCone	3	2	Eastern Montana	County	McCone Service Area	County
Dawson	2	0	NA*	NA	NA	NA
Prairie	1	1	Eastern Montana	County	Miles City Service Area	County
Fallon	3	1	-	-	-	-
Carter	1	0	NA	NA	NA	NA
Subtotal Montana	*17*	*9*	4	-	4	-
South Dakota						
Harding	2	2	Harding	County	Harding Service Area	County
Butte	1	0	NA	NA	NA	NA
Perkins	1	1	Catchment Area 8	County	Perkins Service Area	County
Meade	2	0	NA	NA	NA	NA
Ziebach	1	1	-	-	-	-
Pennington	1	0	NA	NA	NA	NA
Haakon	2	1	Catchment Area 2	County	West Haakon Service Area	Minor Civil Division

TABLE 3.10.1-18
Designated HPSAs and MUA/Ps with Identified Minority and/or Low-Income Populations within Census Block Groups in Affected Counties along the Proposed Project Corridor

County	Total Number of Census Block Groups Assessed	Census Block Groups Containing One or More Identified Minority and/or Low-Income Population[a]	HPSA[b]		MUA/P[cd]	
			Designation Name / Facility Address	Geographic Area or Facility Type	Designation Name	Geographic Area
			Philip Clinic *503 W. Pine St.* *Philip, SD 57567*	Rural Health Center	-	-
Jones	1	1	Catchment Area 2	County	Jones Service Area	County
Lyman	1	1	Catchment Area 2	County	Lyman Service Area	County
			Lower Brule Sioux Tribe Clinic *601 Gall St.* *Lower Brule, SD 57548*	Indian Reservation	-	-
Tripp	8	7	Catchment Area 10	County	Tripp Service Area	County
Gregory	1	1	Catchment Area 10	County	Gregory Service Area	County
Subtotal South Dakota	*21*	*15*	9	-	7	-
Nebraska						
Keya Paha	1	1	Catchment Area 4	County	Keya Paha Service Area	County
Rock	1	1	Catchment Area 4	County	Rock Service Area	County
			Greater Sandhills Family Healthcare *101 E. South St.* *Bassett, NE 68714*	Rural Health Center	-	-
Holt	2	2	Catchment Area 4	County	Holt Service Area	County
			West Holt Medical Clinic *405 W. Pearl St.* *Atkinson, NE 68713*	Rural Health Center	-	-
			Greater Sandhills Family Healthcare *418 E. 5th St.* *Atkinson, NE 68713*	Rural Health Center	-	-

TABLE 3.10.1-18
Designated HPSAs and MUA/Ps with Identified Minority and/or Low-Income Populations within Census Block Groups in Affected Counties along the Proposed Project Corridor

County	Total Number of Census Block Groups Assessed	Census Block Groups Containing One or More Identified Minority and/or Low-Income Population[a]	HPSA[b]		MUA/P[cd]	
			Designation Name / Facility Address	Geographic Area or Facility Type	Designation Name	Geographic Area
			Greater Sandhills Family Healthcare	Rural Health Center	-	-
			110 W. 2nd St. *Stuart, NE 68780*			
			Avera Family Medicine *403 E. Hynes Ave.* *O'Neill, NE 68763*	Rural Health Center	-	-
			Avera Holt County Medicine Clinic *555 E. John St.* *O'Neill, NE 68763*	Rural Health Center	-	-
Garfield	1	0	NA	NA	NA	NA
Wheeler	1	1	Catchment Area 3	County	Wheeler Service Area	County
Greeley	2	0	NA	NA	NA	NA
Boone	2	0	NA	NA	NA	NA
Nance	1	1	Catchment Area 4	County	Genoa Service Area	County
			Lone Tree Medical Associates *901 Broadway St.* *Fullerton, NE 68638*	Rural Health Center	-	-
			Park Street Medical Clinic *505 S. Park St.* *Genoa, NE 68640*	Rural Health Center	-	-
Merrick	2	0	NA	NA	NA	NA
Hamilton	1	0	NA	NA	NA	NA
Polk	1	0	NA	NA	NA	NA
York	3	0	NA	NA	NA	NA

TABLE 3.10.1-18
Designated HPSAs and MUA/Ps with Identified Minority and/or Low-Income Populations within Census Block Groups in Affected Counties along the Proposed Project Corridor

County	Total Number of Census Block Groups Assessed	Census Block Groups Containing One or More Identified Minority and/or Low-Income Population[a]	HPSA[b]		MUA/P[cd]	
			Designation Name / Facility Address	Geographic Area or Facility Type	Designation Name	Geographic Area
Fillmore	2	0	NA	NA	NA	NA
Saline	2	0	NA	NA	NA	NA
Jefferson	3	1	-	-	-	-
Subtotal Nebraska	*25*	*7*	13	-	5	-
New Pump Stations – Kansas						
Clay	4	1	Mental Health Area 14	County	Low Income - Clay County[d]	County
			Clay Center Family Physicians *609 Liberty St.* *Clay Center, KS 67432*	Rural Health Center	-	-
Butler	1	0	NA	NA	NA	NA
Subtotal Kansas	*5*	*1*	2	-	1	-
Gulf Coast Segment						
Oklahoma						
Payne	2	1	Catchment Area 11	County	-	-
			Iowa Tribe of Oklahoma: Perkins Family Clinic *335588 E. 750 Rd.* *Perkins, OK 74059*	Native American Tribal Population	-	-
Creek	2	0	NA	NA	NA	NA
Lincoln	6 (1)[f]	2 (1)[f]	Black Hawk Health Center *356110 East 930 Rd.* *Stroud, Ok 74079*	Native American Tribal Population	Lincoln Service Area	County

TABLE 3.10.1-18
Designated HPSAs and MUA/Ps with Identified Minority and/or Low-Income Populations within Census Block Groups in Affected Counties along the Proposed Project Corridor

County	Total Number of Census Block Groups Assessed	Census Block Groups Containing One or More Identified Minority and/or Low-Income Population[a]	HPSA[b]		MUA/P[cd]	
			Designation Name / Facility Address	Geographic Area or Facility Type	Designation Name	Geographic Area
Okfuskee	5	4	Low Income Catchment Area 13	County	Okfuskee Service Area	County
			Okemah Indian Health Center *309 N. 14th St.* *Okemah, OK 74859*	Native American Tribal Population	-	-
Seminole	5	4	Catchment Area 7	County	Seminole Service Area	County
			Central Oklahoma Family Medical Center *527 W. 3rd St.* *Konawa, OK 74849*	Comprehensive Health Center	-	-
			Seminal Nation of Oklahoma – Wewoka Indian Health Clinic *S. Hwy. 56 & U.S. Hwy. 270 Junction* *Wewoka, OK 74884*	Native American Tribal Population	-	-
Hughes	9	8	Catchment Area 6	County	Hughes Service Area	County
			East Central Oklahoma Family Health Center *401 S. Washita St.* *Wetumka, OK 74883*	Comprehensive Health Center	-	-
Pontotoc	3	3	Catchment Area 7	County	Pontotoc Northeast Service Area	Minor Civil Division
			-	-	Pontotoc Northwest Service Area	Minor Civil Division
			-	-	Pontotoc Southwest Service Area	Minor Civil Division

TABLE 3.10.1-18
Designated HPSAs and MUA/Ps with Identified Minority and/or Low-Income Populations within Census Block Groups in Affected Counties along the Proposed Project Corridor

County	Total Number of Census Block Groups Assessed	Census Block Groups Containing One or More Identified Minority and/or Low-Income Population[a]	HPSA[b]		MUA/P[cd]	
			Designation Name / Facility Address	Geographic Area or Facility Type	Designation Name	Geographic Area
			Carl Albert Indian Hospital *1001 N. Country Club Rd. Ada, OK 74820*	Indian Health Service Facility	-	-
Coal	3	3	Catchment Area 6	County	Coal Service Area	County
Atoka	6	4	Catchment Area 6	County	Atoka Service Area	County
			ABC Medical Clinic *1508 S. Virginia Ave. Atoka, OK, 74525*	Rural Health Center	-	-
			Mack Alford Correctional Center *1151 N. U.S. Hwy. 69 Stringtown, OK 74569*	Correctional Facility	-	-
Bryan	3	3	Catchment Area 7	County		
			Choctaw Nation of Oklahoma - Durant Family Medicine Clinic *1600 W. University Blvd. Durant, OK 74701*	Native American Tribal Population	-	-
			Choctaw Nation of Oklahoma - Durant Health Center *1600 N. Washington Ave. Durant, OK 74701*	Native American Tribal Population	-	-
Choctaw	1	1	Catchment Area 6	County	Choctaw Service Area	County
			Choctaw Nation Health Clinic *410 N. M St. Hugo, OK 74743*	Native American Tribal Population	-	-
Subtotal Oklahoma	*45 (1)[f]*	*33 (1)[f]*	21	-	10	-

TABLE 3.10.1-18
Designated HPSAs and MUA/Ps with Identified Minority and/or Low-Income Populations within Census Block Groups in Affected Counties along the Proposed Project Corridor

County	Total Number of Census Block Groups Assessed	Census Block Groups Containing One or More Identified Minority and/or Low-Income Population[a]	HPSA[b]		MUA/P[cd]	
			Designation Name / Facility Address	Geographic Area or Facility Type	Designation Name	Geographic Area
Texas						
Fannin	2	0	NA	NA	NA	NA
Lamar	6	3	-	-	Lamar Service Area	County
Delta	1	1	-	-	Delta Service Area	County
Hopkins	5	3	-	-	Hopkins Service Area	County
Franklin	3	1	-	-	Franklin Service Area	County
Wood	8	3	Wood	County	Wood Service Area	County
			ETMC First Physician Health Clinic *5875 S. Hwy. 37* *Mineola, TX 75773*	Rural Health Clinic	-	-
Upshur	6	1	-	-	Upshur Service Area	County
Smith	12	8	Community Health Clinic of Northeast Texas *928 N. Glenwood Blvd.* *Tyler, TX 75702*	Comprehensive Health Center	Northern Tyler Service Area	CTs** 1, 2.01, 2.02, 3, 4, 6
			-	-	Troup Service Area	CT 21
			-	-	Smith Service Area	CTs 5, 7
Rusk	4	4	Rusk	County	Rusk Service Area	County
			Mount Enterprise Community Health Clinic *106 W. Rusk St.* *Mount Enterprise, TX 75681*	Federally Qualified Health Center	-	-
Cherokee	5	2	Cherokee	County	South Cherokee County	CTs 9508, 9509, 9510, 9511

TABLE 3.10.1-18
Designated HPSAs and MUA/Ps with Identified Minority and/or Low-Income Populations within Census Block Groups in Affected Counties along the Proposed Project Corridor

County	Total Number of Census Block Groups Assessed	Census Block Groups Containing One or More Identified Minority and/or Low-Income Population[a]	HPSA[b]		MUA/P[cd]	
			Designation Name / Facility Address	Geographic Area or Facility Type	Designation Name	Geographic Area
			Rusk State Hospital *1601 S. Dickinson Dr.* *Rusk, TX 75785*	State Mental Hospital	-	-
Nacogdoches	5	2	East Texas Community Health Services *1401 S. University Dr.* *Nacogdoches, TX 75961*	Comprehensive Health Center	Nacogdoches Service Area[de]	County
Angelina	11 (1)[f]	7 (1)[f]	Duncan Prison *1502 S. 1st St.* *Diboll, TX 75941*	Correctional Facility	Huntington Division Service Area	Huntington, Zavalia Minor Civil Division
			Lufkin State School *6844 U.S. Hwy.* *Pollok, TX 75969*	State Mental Hospital	-	-
Trinity	2	1	Trinity	County	Trinity Service Area	County
Polk	9	5	Polunsky Prison *3872 F.M. Rd. 350* *Livingston, TX 77351*	Correctional Facility	Polk Service Area	County
San Jacinto	1	0	NA	NA	NA	NA
Liberty	6	4	Health Center of Southeast Texas *401 E. Crockett St.* *Cleveland, TX 77327*	Comprehensive Health Center	Liberty Service Area	County
Hardin	5	2	Hardin	County	Hardin Service Area	County
Jefferson	43 (14)[f]	21 (7)[f]	Gulf Coast Health Center	Comprehensive	Port Arthur/Jefferson Service Area	CTs 51, 53, 54, 59, 59, 61, 62, 63, 69, 71
			2548 Memorial Blvd. *Port Arthur, TX 77640*	Health Center		

TABLE 3.10.1-18
Designated HPSAs and MUA/Ps with Identified Minority and/or Low-Income Populations within Census Block Groups in Affected Counties along the Proposed Project Corridor

County	Total Number of Census Block Groups Assessed	Census Block Groups Containing One or More Identified Minority and/or Low-Income Population[a]	HPSA[b]		MUA/P[cd]	
			Designation Name / Facility Address	Geographic Area or Facility Type	Designation Name	Geographic Area
			Federal Corrections Complex *5830 Knauth Rd. Beaumont, TX 77715*	Correctional Facility	Low Income - Jefferson Service Area[d]	CTs 113.01, 114, 115, 116
			-	-	Low Income - Inner City Beaumont[d]	CTs 1.03, 6, 7, 9, 10, 16, 17, 19, 20, 21, 22, 23, 24, 25, 26
Orange	1	1	-	-	Orange Service Area	CTs 202, 203, 208
			-	-	Vidor Service Area[de]	CTs 207, 214, 215, 216, 217, 218, 219, 220, 222
Subtotal Texas - Gulf Coast Segment	*135 (15)[f]*	*69 (8)[f]*	16	-	22	-
Houston Lateral						
Liberty	17	10	Health Center of Southeast Texas *401 E. Crockett St. Cleveland, TX 77327*	Comprehensive Health Center	Liberty Service Area	County
Chambers	2	0	NA	NA	NA	NA
Harris	24	16 (1)[f]	Third Ward Service Area	CTs 3122, 3123, 3124, 3125, 3128	Harris Service Area	CTs 4101, 4102, 4103, 4104, 4105, 4106
			East Central Service Area	CTs 2108, 2109, 2110, 2111, 2112, 2113,	Southern Third Ward Service Area	CTs 3122, 3123, 3124, 3127, 3128,

TABLE 3.10.1-18
Designated HPSAs and MUA/Ps with Identified Minority and/or Low-Income Populations within Census Block Groups in Affected Counties along the Proposed Project Corridor

County	Total Number of Census Block Groups Assessed	Census Block Groups Containing One or More Identified Minority and/or Low-Income Population[a]	HPSA[b]		MUA/P[cd]	
			Designation Name / Facility Address	Geographic Area or Facility Type	Designation Name	Geographic Area
				2114, 2115, 2116, 2117, 2118, 2119, 2120, 2121, 2122		3129, 3130, 3132, 3133, 3134, 3135, 3136, 3137, 3138
			Casa De Amigos Catchment Area	CTs 2103, 2104, 2105, 2106, 2107, 5102, 5103, 5104, 5105, 5106, 5107, 5113, 5114, 5116	West Pasadena	CTs 3219, 3220, 3220, 3223, 3224, 3229, 3230, 3231, 3232
			Northeast Harris Service Area	CTs 2201, 2208, 2301, 2302, 2303, 2304, 2305, 2306, 2307, 2308, 2309, 2310, 2311, 2312, 2313, 2314, 2315, 2316, 2319, 2320	South Service Area	CTs 3311, 3312
			Acres Home Service Area	CTs 5308, 5318, 5319, 5320, 5326, 5327, 5328, 5329, 5330, 5331, 5332, 5333, 5334	Northeast Central Service Area	CTs 3110, 3111
			Aldine Service Area	CTs 2218, 2219, 2220, 2221,	Central Harris Service Area	CTs 2102, 2113, 2114,

TABLE 3.10.1-18
Designated HPSAs and MUA/Ps with Identified Minority and/or Low-Income Populations within Census Block Groups in Affected Counties along the Proposed Project Corridor

County	Total Number of Census Block Groups Assessed	Census Block Groups Containing One or More Identified Minority and/or Low-Income Population[a]	HPSA[b]		MUA/P[cd]	
			Designation Name / Facility Address	Geographic Area or Facility Type	Designation Name	Geographic Area
						5101
				2222, 2223, 2229, 2230, 2231, 2317		
			Low Income – Ripley Service Area	CTs 3104, 3105, 3106, 3108, 3109, 3110, 3111, 3112, 3113, 3114, 3115, 3116, 3117, 3118, 3119, 3202, 3203, 3329	North Forest Service Area	CTs 2312, 2313, 2314, 2315, 2316, 2318, 2319, 2320, 2321, 2322, 2323
			South Central Houston Service Area	CTs 3308, 3311, 3312, 3313, 3314, 3315, 3316, 3317, 3318, 3319, 3320, 3321, 3322, 3323, 3324, 3326, 3327, 3328,	East Central Houston Service Area	CTs 2112, 2115, 2116, 2117, 2118, 2119, 2120, 2121, 2122
			Houston Healthcare for the Homeless *2505 Fannin St. Houston, TX 77002*	Comprehensive Health Center	Ripley Service Area	CTs 3101, 3103, 3104, 3105, 3106, 3107, 3108, 3109, 3112, 3113, 3114, 3115, 3117,

TABLE 3.10.1-18
Designated HPSAs and MUA/Ps with Identified Minority and/or Low-Income Populations within Census Block Groups in Affected Counties along the Proposed Project Corridor

County	Total Number of Census Block Groups Assessed	Census Block Groups Containing One or More Identified Minority and/or Low-Income Population[a]	HPSA[b]		MUA/P[cd]	
			Designation Name / Facility Address	Geographic Area or Facility Type	Designation Name	Geographic Area
						3118, 3119
			Harris County Hospital District *2525 Holly Hall St. Houston, TX 77054*	Comprehensive Health Center	South Central Harris County Service Area	CTs 3308, 3314, 3315, 3316, 3317, 3318, 3319, 3320, 3321, 3322, 3323, 3324, 3326, 3327, 3328
			South Central Houston Community Health Center *8610 Martin Luther King Blvd. Houston, TX 77033*	Comprehensive Health Center	Casa De Amigos Service Area	CTs 2103, 2104, 2105, 2106, 2107, 5102, 5103, 5104, 5105, 5106, 5107, 5113, 5114, 5116
			Spring Branch Community Health Center *1615 Hillendahl Blvd. Houston, TX 77055*	Comprehensive Health Center	Baytown Service Area	CTs 2534, 2541, 2542, 2543, 2544, 2545, 2546
			Pasadena Health Center *524 Pasadena Blvd. Pasadena, TX 77506*	Comprehensive Health Center	Galena Park/Jacinto City Service Area	CTs 2333, 2335, 2336, 2337
			Fourth Ward Clinic *277 W. Gray St. Houston, TX 77019*	Comprehensive Health Center	Acres Home Service Area	CTs 5308, 5318, 5319, 5327, 5331, 5333, 5334
			Legacy Community Health Systems *215 Westheimer Rd.*	Comprehensive Health Center	Settegast Service Area	CTs 2201, 2207, 2208,

TABLE 3.10.1-18
Designated HPSAs and MUA/Ps with Identified Minority and/or Low-Income Populations within Census Block Groups in Affected Counties along the Proposed Project Corridor

County	Total Number of Census Block Groups Assessed	Census Block Groups Containing One or More Identified Minority and/or Low-Income Population[a]	HPSA[b]		MUA/P[cd]	
			Designation Name / Facility Address	Geographic Area or Facility Type	Designation Name	Geographic Area
			Houston, TX 77006			2209, 2301, 2302, 2303, 2304, 2305, 2306, 2307, 2308, 2309, 2310, 2311
			El Centro De Corazon *5001 Navigation Blvd. Houston, TX 77011*	Comprehensive Health Center	Aldine Settegast Service Area	CTs 2218, 2219, 2221, 2222, 2229, 2317
			Houston Community Health Center *424 Hahlo St. Houston, TX 77020*	Comprehensive Health Center	North Central Service Area	CTs 2217, 2224, 2225, 2228, 2401, 2402, 2405
			Hope Clinic *7001 Corporate Dr. Houston, TX 77036*	Federally Qualified Health Center	Independence Heights Service Area	CTs 2202, 2203, 2204, 2205, 2206, 5303, 5304, 5305
			Immigration and Customs Enforcement *15850 Export Plaza Dr. Houston, TX 77032*	Correctional Facility	Trinity Gardens Service Area	CTs 2108, 2109, 2110, 2111
			Houston Area Community Services *3730 Kirby Dr. Houston, TX 77098*	Comprehensive Health Center	Low Income - Spring Branch Service Area[d]	CTs 5201, 5202, 5203, 5204, 5205, 5206, 5207, 5210, 5211, 5212, 5213, 5214, 5215, 5216, 5217,

TABLE 3.10.1-18
Designated HPSAs and MUA/Ps with Identified Minority and/or Low-Income Populations within Census Block Groups in Affected Counties along the Proposed Project Corridor

County	Total Number of Census Block Groups Assessed	Census Block Groups Containing One or More Identified Minority and/or Low-Income Population[a]	HPSA[b]		MUA/P[cd]	
			Designation Name / Facility Address	Geographic Area or Facility Type	Designation Name	Geographic Area
						5218, 5219, 5220, 5221, 5222, 5223, 5224, 5401
			Motherland *4040 Yale St. Houston, TX 77018*	Comprehensive Health Center	Low Income - Alief Service Area[d]	CTs 4330, 4332, 4334
			Federal Detention Center Houston *1200 Texas St. Houston, TX 77002*	Correctional Facility	Poverty/Spanish Speaking/Immigration Population - Southwest Houston[de]	CTs 4211, 4213, 4214, 4215, 4216, 4319, 4325, 4327, 4328, 4329
			-	-	Governor's Low Income - Southwest Harris County[de]	CTs 4336, 4532, 4533, 4534, 4535, 4536, 4537, 4538
			-	-	Low Income - Northwest Harris County[de]	CTs 2226, 2401, 2405, 2406, 5501, 5502, 5503, 5504, 5505, 5506, 5511, 5532, 5533
Subtotal Texas - Houston Lateral	*43 (2)*[f]	26 (1)[f]	23	-	25	-
Subtotal Texas[g]	*174 (17)*[f]	93 (9)[f]	38	-	46	-
Project Total	**287 (18)**[f]	**158**[a] **(10)**[f]	**87**	**-**	**73**	-

*NA = Not Applicable
**CT = Census Tract
[a] Of the 158 census block groups that did show state-wide exceedances for minority and/or low-income populations, 136 showed exceedances for one or more minority populations, 22 showed exceedances for only low-income populations, and 26 showed exceedances for one or more minority populations along with a low-income population.
[b] Health Professional Shortage Areas (HPSAs) were assessed in counties where minority and/or low-income populations were identified. HPSAs may be designated as having a shortage of primary medical care, dental or mental health providers. They may be urban or rural areas, population groups, medical facilities or other public facilities. Addresses are listed for medical and other public facilities. See Figures 3.10.1-7 through 3.10.1-13 for locations of HPSA areas.
[c] Medically Underserved Areas/Populations (MUA/Ps) were assessed in counties where minority and/or low-income populations were identified. MUAs may be a whole county or a group of contiguous counties, a group of county or civil divisions or a group of urban census tracts in which residents have a shortage of personal health services. MUPs may include groups of persons who face economic, cultural or linguistic barriers to health care. See Figures 3.10.1-7 through 3.10.1-13 for locations of MUA/P areas.
[d] Medically Underserved Population (MUP) designation.
[e] MUP designated at request of State Governor based on documented unusual local conditions and barriers to assessing personal health services.
[f] Numbers in parentheses indicate number of census block groups fully contained within the 4-mile-wide analysis area.
[g] Four census block groups in Liberty County (CT 7006 BG 3, CT 7007 BG 1, CT 7013 BG 1, BG 3) affected by both the Gulf Coast Segment and Houston Lateral were only counted once in the Texas subtotal. Liberty County was only counted once for HPSAs and MUA/Ps.

Sources: U.S. Census Bureau. 2002. Census Block Group SF3: 2000. Table P6 – Race. Table P7 – Hispanic or Latino by Race. Washington, D.C.
U.S. Census Bureau. 2002. Census Block Group SF3: 2000. Table P87 – Poverty Status in 1999 by Age. Washington, D.C.
See http://factfinder.census.gov/home.
U.S. Department of Health and Human Services. Health Resources and Services Administration. HPSAs and MUA/Ps data warehouse.
See http://datawarehouse.hrsa.gov/datadownload.aspx.

Operations Impacts

This section was originally 3.10.2.2 in the draft EIS. There have been no substantive changes to this section and therefore it is not included in the SDEIS. The draft EIS subsection can be downloaded at www.keystonepipeline-xl.state.gov.

3.10.2 Public Services, Tax Revenues, and Property Values

This section was presented in subsections 3.10.1.5, 3.10.1.6, and 3.10.2.2 in the draft EIS. There have been no substantive changes to this section and therefore it is not included in the SDEIS. The draft EIS subsection can be downloaded at www.keystonepipeline-xl.state.gov.

3.10.3 Traffic and Transportation

This was Section 3.10.1.8 in the draft EIS. There have been no substantive changes to this section and therefore it is not included in the SDEIS. The draft EIS subsection can be downloaded at www.keystonepipeline-xl.state.gov.

3.10.4 Connected Actions

There have been no changes to the environmental assessment for electrical distribution lines and substations or the Big Bend to Witten 230-kV transmission line (formerly the Lower Brule to Witten 230-kV transmission line). The draft EIS subsection can be downloaded at www.keystonepipeline-xl.state.gov. Potential impacts associated with the Bakken Marketlink Project and the Cushing Marketlink Project are addressed in Section 3.15 of this SDEIS.

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[FIGURE PLACEHOLDER]

3.10.1-1 Environmental Justice (Montana)

3.10.1-2 Environmental Justice (South Dakota)

3.10.1-3 Environmental Justice (Nebraska)

3.10.1-4 Environmental Justice (Kansas)

3.10.1-5 Environmental Justice (Oklahoma)

3.10.1-6 Environmental Justice (Texas)

3.10.1-7 Environmental Justice Analysis - HPSA and MUA Locations (Montana)

3.10.1-8 Environmental Justice Analysis - HPSA and MUA Locations (South Dakota)

3.10.1-9 Environmental Justice - HPSA and MUA Locations (Nebraska)

3.10.1-10 Environmental Justice - HPSA and MUP Locations (Kansas)

3.10.1-11 Environmental Justice - HPSA and MUA Locations (Oklahoma)

3.10.1-12 Environmental Justice - HPSA and MUA Locations (Texas)

3.10.1-13 Environmental Justice - HPSA and MUA/P Locations (Harris County, Texas)

3.11 CULTURAL RESOURCES

There have been no changes to the environmental assessment presented in this section, including the assessment of the electrical distribution lines and substations and the Big Bend to Witten 230-kV transmission line (formerly the Lower Brule to Witten 230-kV transmission line). However, as a result of a request for financing from BEPC to the RUS, compliance with Section 106 of the NHPA will be the responsibility of the RUS as lead federal agency. Potential impacts associated with the Bakken Marketlink Project and the Cushing Marketlink Project are addressed in Section 3.15 of this SDEIS.

3.12 AIR QUALITY AND NOISE

This section provides supplemental information on regulatory requirements for greenhouse gas (GHG) that were enacted after the draft EIS was issued. Information on the cumulative impacts of GHG and on climate change is presented in Section 3.14.3.14.

3.12.1 Air Quality

3.12.1.1 Environmental Setting

There have been no substantive changes to this section and therefore it is not included in the SDEIS. The draft EIS subsection can be downloaded at www.keystonepipeline-xl.state.gov.

3.12.1.2 Regulatory Requirements

Greenhouse Gas Regulatory Requirements

On October 30, 2009, the EPA promulgated the first comprehensive national system for reporting emissions of carbon dioxide (CO_2) and other GHG produced by major sources in the United States. Through this new reporting, EPA will have comprehensive and accurate data about the production of GHG in order to confront climate change. Approximately 13,000 facilities, accounting for about 85 to 90 percent of industrial GHG emitted in the United States are covered under the rule. The new reporting requirements apply to suppliers of fossil fuel and industrial chemicals, manufacturers of certain motor vehicles and engines (not including light and medium duty on-road vehicles), as well as large direct emitters of GHG with emissions equal to or greater than a threshold of 25,000 metric tpy. This threshold is equivalent to the annual GHG emissions from just over 4,500 passenger vehicles. The direct emission sources covered under the reporting requirement include energy intensive sectors such as cement production, iron and steel production, electricity generation, and oil refineries, among others. The gases covered by the rule are CO_2, methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons (HFC), perfluorocarbons (PFC), sulfur hexafluoride (SF_6), and other fluorinated gases, including nitrogen trifluoride (NF_3) and hydrofluorinated ethers (HFE). Because CO_2 is the reference gas for climate change, measures of non-CO_2 GHG are converted into CO_2-equivalent values (CO_2-e) based on their potential to absorb heat in the atmosphere. The first annual report would be submitted to EPA in 2011 for the calendar year 2010, except for vehicle and engine manufacturers, which would begin reporting for model year 2011.

According to the preamble of the rule, the U.S. petroleum and natural gas industry encompasses hundreds of thousands of wells, hundreds of processing facilities, and over a million miles of transmission and distribution pipelines. Crude oil is commonly transported by barge, tanker, rail, truck, and pipeline from production operations and import terminals to petroleum refineries or export terminals. Typical equipment associated with these operations includes storage tanks and pumping stations. The major sources of CH_4 and CO_2 fugitive emissions include releases from tanks and marine vessel loading

operations. EPA does not propose to include the crude oil transportation segment of the petroleum and natural gas industry in this rulemaking due to its small contribution to total petroleum and natural gas fugitive emissions (accounting for much less than 1 percent) and the difficulty in defining a facility. The responsibility for reporting would instead be placed on the processing plants and refineries. Consequently, the proposed pipeline Project would not trigger GHG reporting requirements.

On June 2, 2010, the EPA issued a final rule that establishes an approach to addressing GHG emissions from stationary sources under the CAA permitting programs. These stationary sources would be required to obtain permits that would demonstrate they are using the best practices and technologies to minimize GHG emissions. The rule sets thresholds for GHG emissions that define when the CAA permits under the NSR/PSD and the Title V Operating Permits programs are required for new or existing industrial facilities. The rule "tailors" the requirements to limit which facilities will be required to obtain NSR/PSD and Title V permits and cover nearly 70 percent of the national GHG emissions that come from stationary sources, including those from the nation's largest emitters (e.g., power plants, refineries, and cement production facilities).

For sources permitted between January 2, 2011 and June 30, 2011, the rule requires GHG permitting for only sources currently subject to the PSD permitting program (i.e., those that are newly-constructed or modified in a way that significantly increases emissions of a pollutant other than GHG) and that emit GHG emissions of at least 75,000 tpy. In addition, only sources required to have Title V permits for non-GHG pollutants will be required to address GHG as part of their Title V permitting (note: the 75,000 tpy CO_2-e limit does not apply to Title V). For sources constructed between July 1, 2011 and June 30, 2013, the rule requires PSD permitting for first-time new construction projects that emit GHG emissions of at least 100,000 tpy even if they do not exceed the permitting thresholds for any other pollutant. In addition, sources that emit or have the potential to emit at least 100,000 tpy CO_2-e and that undertake a modification that increases net emissions of GHG by at least 75,000 tpy CO_2-e will also be subject to PSD requirements. Under this scenario, operating permit requirements will for the first time apply to sources based on their GHG emissions, even if they would not apply based on emissions of any other pollutant. Facilities that emit at least 100,000 tpy CO_2-e will be subject to Title V permitting requirements. The proposed Project is not subject to PSD and would have emissions of CO_2-e less than the applicable thresholds for any of the stationary sources (i.e., construction camp, tank farm, and surge relief tanks). Note that emissions from fugitive dust and mobile sources (on-road and non-road) are not included in the emission estimates for permit applicability of a stationary source. Consequently, the proposed Project would not be subject to the federal GHG permitting rule. EPA plans further rulemaking that would possibly reduce the permitting thresholds for new and modified sources making changes after June 30, 2013.

Information on the cumulative impacts of GHG and climate change are addressed in Section 3.14.3.14 of the SDEIS.

3.12.1.3 Potential Impacts and Mitigation

There have been no substantive changes to this section and therefore it is not included in the SDEIS. The draft EIS subsection can be downloaded at www.keystonepipeline-xl.state.gov.

3.12.1.4 Connected Actions

There have been no changes to the environmental assessment for electrical distribution lines and substations or the Big Bend to Witten 230-kV transmission line (formerly the Lower Brule to Witten 230-kV transmission line). The draft EIS subsection can be downloaded at www.keystonepipeline-

xl.state.gov. Potential impacts associated with the Bakken Marketlink Project and the Cushing Marketlink Project are addressed in Section 3.15 of this SDEIS.

3.12.2 Noise

There have been no changes to the environmental assessment presented in this section, including the assessment of the electrical distribution lines and substations and the Big Bend to Witten 230-kV transmission line (formerly the Lower Brule to Witten 230-kV transmission line). The draft EIS subsection can be downloaded at www.keystonepipeline-xl.state.gov. Potential impacts associated with the Bakken Marketlink Project and the Cushing Marketlink Project are addressed in Section 3.15 of this SDEIS.

3.13 POTENTIAL RELEASES FROM PROJECT CONSTRUCTION AND OPERATION AND ENVIRONMENTAL CONSEQUENCES ANALYSIS

This section addresses the potential for and consequences of oil products or crude oil releases that could occur during construction and operation of the proposed Project. The analyses presented in the draft EIS were revised for the SDEIS based on comments on the draft EIS, information that was updated after the draft EIS was issued, and information that was unavailable at the time the draft EIS was issued. This information includes recent PHMSA incident databases for hazardous liquid pipelines and the 57 Project-specific Special Conditions developed by PHMSA and agreed to by Keystone. As a result, there are revisions throughout Section 3.13 and the entire revised section is included in this SDEIS.

Safety regulatory requirements and standards, the risk of crude oil and oil product releases, and the environmental consequences of those potential releases are addressed in the following subsections:

- Pipeline Safety Considerations (Section 3.13.1);
- Potential Types of Releases and Volumes from Project Construction and Operation (Section 3.13.2);
- Potential Releases During Project Construction (Section 3.13.3);
- Potential Releases from Project Operations (Section 3.13.4);
- Impacts Related to Oil Spills (Section 3.13.5); and
- Resource-Specific Impacts (Section 3.13.6).

3.13.1 Pipeline Safety Considerations

3.13.1.1 Pipeline Safety Standards and Regulations

U.S. Department of Transportation Regulations

USDOT is mandated to regulate pipeline safety under Title 49, USC Chapter 601. PHMSA is responsible for protecting the American public and the environment by ensuring the safe and secure movement of hazardous materials to industry and consumers by all transportation modes, including the nation's pipelines. Through PHMSA, the USDOT develops and enforces regulations for the safe, reliable, and environmentally sound operation of the nation's 2.3-million-mile pipeline transportation system and the nearly 1 million daily shipments of hazardous materials by land, sea, and air. Within PHMSA, OPS has the safety authority for the nation's natural gas and hazardous liquid pipelines. PHMSA administers the national regulatory program to ensure the safe transportation of hazardous liquids, including crude oil, by

pipeline. PHMSA develops regulations that address safety in the design, construction, testing, operation, maintenance, and emergency response for hazardous liquid pipelines and related facilities. Many of the regulations are written as performance standards that set the level of safety to be attained and allow the pipeline operators to use various technologies to achieve the required level of safety. PHMSA is responsible for regulations that require safe operations of hazardous liquid pipelines to protect human health and the environment from unplanned pipeline incidents.

The regulations governing pipeline safety are included in 49 CFR Parts 190 through 199 (available at http://ecfr.gpoaccess.gov/cgi/t/text/text-idx?sid=ca3d88e943c9b3619f96ac3d22f1c200&c=ecfr&tpl=/ecfrbrowse/Title49/49cfrv3_02.tpl%20). Parts 190, 194, 195, 198, and 199 are relevant to hazardous liquid (including crude oil) pipelines. Individual states are permitted to adopt additional or more stringent safety regulations for intrastate pipelines. Parts 190, 198, and 199 address issues that are tangential to pipeline system integrity. The regulations at 49 CFR 190 (Pipeline Safety Programs and Rulemaking Procedures) describe the pipeline safety programs and rulemaking procedures used by PHMSA in carrying out its regulatory duties, authorize PHMSA to inspect pipelines, describe the procedures by which PHMSA can enforce the regulations, and describe the legal rights and options of the operating companies in response to PHMSA enforcement actions. The regulations at 49 CFR 198 (Regulations for Grants to Aid State Pipeline Safety Programs) prescribe regulations for grants to aid state pipeline safety compliance programs. The regulations at 49 CFR 199 (Drug and Alcohol Testing) require operators of natural gas, liquefied natural gas, and hazardous liquid pipeline facilities to establish programs for preventing alcohol misuse and to test employees for the presence of alcohol and prohibited drugs.

Regulations that are more directly related to pipeline system integrity and the associated oil spill risk assessment and environmental consequences analyses are addressed in the following paragraphs. The regulations at 49 CFR 194 (Response Plans for Onshore Oil Pipelines) contain requirements for onshore oil spill response plans that are intended to reduce the environmental impact of oil unintentionally discharged from onshore oil pipelines. Additional information on the requirements of 49 CFR 194 is presented later in this section.

The regulations at 49 CFR 195 (Transportation of Hazardous Liquids by Pipeline) include the design, construction, operation, and maintenance safety standards and reporting requirements for pipelines that transport hazardous liquids, including crude oil. Subparts of 49 CFR 195 include:

- Subpart A: General;
- Subpart B: Annual Accident and Safety-Related Condition Reporting;
- Subpart C: Design Requirements;
- Subpart D: Construction;
- Subpart E: Pressure Testing;
- Subpart F: Operation and Maintenance;
- Subpart G: Qualification of Pipeline Personnel; and
- Subpart H: Corrosion Control.

The regulations at Subpart A, Section 195.6 define unusually sensitive areas (USAs) as public drinking water or ecological resource areas.

The regulations at Subpart C include specifications for determination of the internal pressure acceptable in relationship to other design parameters (Part 195.106).

The regulations at Subpart F include requirements for marking, inspecting, and maintaining pipelines and the regulations at Subpart F, 49 CFR 195.260 (e) require a valve on either side of water crossings that are more than 100 feet across (as measured from high water marks). The regulations at Subpart F, Section 195.452 specify pipeline integrity management requirements in high-consequence areas (HCAs). An HCA is defined as:

- A commercially navigable waterway, which means a waterway where a substantive likelihood of commercial navigation exists;
- A high population area, which means an urbanized area—as defined and delineated by the U.S. Census Bureau—that contains 50,000 or more people and has a population density of at least 1,000 people per square mile;
- Any other populated area, which means a place—as defined and delineated by the U.S. Census Bureau—that contains a concentrated population, such as an incorporated or unincorporated city, town, village, or other designated residential or commercial area; or
- An unusually sensitive area (USA) — defined in 49 CFR Part 195.6 as public drinking water or ecological resource areas that are unusually sensitive to environmental effects from hazardous liquid pipeline releases.

Drinking water USAs are a subset of all surface water intakes and groundwater-based drinking water supplies, including public water systems, public water supplies from source water protection areas/wellhead protection areas, and sole-source aquifers. Specifically, drinking water USAs include:

- The surface water intakes for community water systems and non-transient non-community water systems that do not have an adequate alternative drinking water source;
- The source water protection areas for community water systems and non-transient, non-community water systems that obtain their water supply from a Class I or Class IIA aquifer and do not have an adequate alternative drinking water source. If the source water protection area is not available, the wellhead protection areas become the USA; and
- The aquifer recharge area for sole-source aquifers within karst terrains.

For a new hazardous liquid pipeline, the regulations at 49 CFR 195.452 require that HCAs be identified prior to operation and that a written Integrity Management Plan (IMP) be in place within 1 year of the start of operation. The HCA regulation also requires that operators of new hazardous liquid pipelines complete baseline assessments by the start date for pipeline operation. Keystone would conduct a baseline assessment consisting of hydrostatic testing and a caliper/geometry pig inspection prior to the proposed pipeline's operation. Keystone also prepared a pipeline risk assessment that comprises incident frequencies and potential spill volumes and fulfills the risk analysis requirements for HCAs (see Appendix P of the draft EIS). The pipeline risk assessment summarizes Keystone's estimate of pipeline miles within various types of HCAs. More detailed analyses would be conducted by Keystone as part of the IMP process that would occur prior to proposed Project operation. PHMSA would review the proposed pipeline's IMP and would conduct periodic inspections of the pipeline during operation. Keystone must implement preventive and mitigating measures to protect each HCA from the consequences of a pipeline failure and release of oil.

Additional actions that may be required include the following:

- Implementing damage prevention Best Management Practices (BMPs);
- Implementing more thorough programs to monitor cathodic protection where corrosion is a concern;
- Establishing shorter inspection intervals;
- Installing emergency flow restriction devices on the pipeline segment;
- Modifying systems that monitor pressure and detect leaks; and
- Providing additional training to personnel on response procedures, conducting drills with local emergency responders, and adopting other management controls.

The regulations at 49 CFR 195 Subpart G include minimum operator qualification requirements for individuals performing tasks required by the regulations, and Subpart H specifies corrosion control requirements.

The regulations at Part 194 require that a response plan be developed, and at Part 195 require that an operations manual be developed that addresses abnormal operations for the proposed Project. Keystone developed an Emergency Response Plan (ERP) for the Keystone Mainline and Cushing Extension that addresses these requirements and that was reviewed and approved by PHMSA prior to operation of that project (see Appendix C of the draft EIS). Keystone has stated that this ERP would serve as the template for an ERP for the proposed Project and Project-specific information would be inserted into that plan as it becomes available (see Section 2.4.2.2).

PHMSA Special Conditions

At the time of publication of the draft EIS, Keystone had applied to PHMSA for consideration of a Special Permit request that if approved, would have allowed Keystone to operate the proposed Project at a slightly higher pressure than would be allowed using the standard design factor (maximum pressure not to exceed 72 percent of the pipe specified minimum yield strength [SMYS]) specified in 49 CFR 195.106. As a part of consideration of the application for a Special Permit, PHMSA initiated development of Special Conditions that, if the permit were granted, would have allowed Keystone to operate the Project at a maximum operating pressure higher than that specified in 49 CFR 195.106. However, on August 5, 2010, Keystone withdrew its application to PHMSA for a Special Permit.

After the application was withdrawn, DOS continued to work with PHMSA and Keystone to develop Special Conditions that could be applied to the proposed Project in response to comments received about pipeline construction, operation, and maintenance. Ultimately, a set of 57 Special Conditions was established (presented in Appendix C of this SDEIS) and Keystone agreed that if the Presidential Permit is granted, it would incorporate those conditions into the proposed Project and in its manual for operations, maintenance, and emergencies that is required by 49 CFR 195.402. PHMSA has the legal authority to inspect and enforce any items contained in a pipeline operator's operations, maintenance, and emergencies manual, and would therefore have the legal authority to inspect and enforce the 57 Special Conditions if the proposed Project is approved. Incorporation of those conditions would result in a Project that would have a degree of safety over any other typically constructed domestic oil pipeline system under current code and a degree of safety along the entire length of the pipeline system similar to that which is required in High Consequence Areas (HCAs) as defined in 49 CFR 195.450.

Standards and Regulations for Affected States

Oversight and inspections of interstate hazardous liquid pipelines are carried out by PHMSA with the assistance of state agencies in the states where PHMSA and the state have a cooperative agreement. In all states that would be crossed by the proposed pipeline, PHMSA regulates, inspects, and enforces interstate liquid pipeline safety requirements. States may adopt regulations with requirements that supplement or exceed federal requirements for intrastate pipelines only.

All states that would be crossed by the proposed Project have adopted state one-call systems to reduce the potential for third-party damage to utilities, including pipelines, during activities that involve excavation or soil boring. During construction and operation, contractors and the operator would be required to use the one-call system in each state to reduce the risk of damage to existing subsurface utilities.

Industry Standards

The proposed Project pipeline design would comply with pertinent industry standards. These industry standards could change if PHMSA adopts updated versions of the standards referenced in 49 CFR 195.3. Standards that would be complied with include the following:

- American Society of Mechanical Engineers (ASME)/American National Standards Institute (ANSI) Code B31.4, "Liquid Transportation Systems for Hydrocarbons, Liquid Petroleum Gas, Anhydrous Ammonia, and Alcohols." This standard addresses requirements for materials of construction welds, inspection, and testing for cross-country hazardous liquid pipelines. ASME B31.4 434.15.2 (a) requires mainline block valves on the upstream side of major river crossings and public water supply reservoirs, and either a block valve or a check valve on the downstream side. 49 CFR Part 195, "Transportation of Hazardous Liquids by Pipelines," has incorporated ASME/ANSI B31.4 code by reference.
- ANSI Standards CSA Z662-03 and Z662.1-03. This standard covers the design, construction, operation, and maintenance of oil and gas industry pipeline systems that convey various fluids, including crude oil.
- American Petroleum Institute (API) 570, "Piping Inspection Code–Inspection, Repair, Alteration, and Re-Rating of In-Service Piping Systems." This code was developed for the petroleum refining and chemical processing industries but may be used for any piping system.
- API RP 1102, "Recommended Practices for Liquid Petroleum Pipelines Crossing Railroads and Highways." This recommended practice is a requirement of ASME/ANSI B31.4.
- API RP 1109, "Recommended Practice for Marking Liquid Petroleum Pipeline Facilities." ASME/ANSI B31.4 advises that this API RP 1109 shall be used as a guide.
- NACE RP 0169, "Control of External Corrosion on Underground or Submerged Metallic Piping Systems." ASME/ANSI B31.4 refers to sections of this recommended practice as a guide for an adequate level of cathodic protection.
- Other documents or portions thereof pertaining to transportation of hazardous liquids and incorporated by reference in 49 CFR 195.3.

Storage tanks associated with the proposed Project or the Bakken Marketlink and Cushing Marketlink connected actions, as well as surge tanks at delivery points in Texas would be designed and constructed in accordance with relevant standards listed in 49 CFR 195. Additionally, Keystone has agreed to incorporate into the proposed Project specifications a set of Project-specific conditions developed by

PHMSA (Appendix C of this SDEIS). These Special Conditions incorporate the requirements of the following industry standards:

- API Specification 5L, Specification for Line Pipe, 44th Edition. API 5L and other specifications and standards address the steel pipe toughness properties needed to resist crack initiation, crack propagation and to ensure crack arrest during a pipeline failure caused by a fracture;
- ASTM International A578/A578M Level B or equivalent. Standard Specification for Straight-Beam Ultrasonic Examination of Rolled Steel Plates for Special Applications;
- API 1104, *"Welding of Pipelines and Related Facilities."* API 1104 covers the gas and arc welding of butt, fillet, and socket welds in carbon and low-alloy steel piping used in the compression, pumping, and transmission of crude petroleum, petroleum products, fuel gases, carbon dioxide, nitrogen and, where applicable, covers welding on distribution systems. It applies to both new construction and in-service welding. This standard also covers the procedures for radiographic, magnetic particle, liquid penetrant, and ultrasonic testing, as well as the acceptance standards to be applied to production welds tested to destruction or inspected by radiographic, magnetic particle, liquid penetrant, ultrasonic, and visual testing methods;
- API Recommended Practice 1165 *(First Edition)*, *Recommended Practice for Pipeline SCADA Displays;*
- API Recommended Practice 1130, *Computational Pipeline Monitoring for Liquid Pipelines,* (API RP 1130, 1st Edition 2007);
- ASME Standard B31Q, *Pipeline Personnel Qualification Standard* (ASME B31Q), September 2006;
- API Recommended Practice 1162, *Public Awareness Programs for Pipeline Operators,* (API RP 1162 (1st edition, December 2003) or the most recent version incorporated in 195.3);
- Canadian Standards Association, *Oil and Gas Pipeline Systems*, CSA Z662-03, Annex E, Section E.5.2, Leak Detection Manual;
- NACE International RP 0169 (2002 or the latest version incorporated by reference in 195.3) and 0177 (2007 or the latest version referenced through the appropriate NACE standard incorporated by reference in 195.3) (NACE RP 0169 and NACE RP 0177) for interference current levels. NACE RP 0169 was described earlier. NACE RP 0177 addresses mitigation of alternating current and lightning effects on metallic structures and corrosion control systems;
- NACE International RP 0502-2002 (NACE RP 0502-2002) Pipeline External Corrosion Direct Assessment Methodology, or the latest version incorporated by reference in 195.3;
- PHMSA's "Interim Guidelines for Confirming Pipe Strength in Pipe Susceptible to Low Yield Strength for Liquid Pipelines" dated October 6, 2009;
- The Common Ground Alliance's damage prevention best practices applicable to pipelines.

Summary

As a result of incorporation of the current PHMSA regulations, current industry standards, and the set of 57 Project-specific Special Conditions developed by PHMSA and agreed to by Keystone, the proposed Project would have a degree of safety over any other typically constructed domestic oil pipeline system under current code and a degree of safety along the entire length of the pipeline system similar to that which is required in HCAs as defined in 49 CFR 195.450.

3.13.1.2 U.S. Pipeline Spill Incident History

PHMSA Pipeline Incident Statistics

PHMSA pipeline incident statistics are addressed in the draft EIS. The following subsection of this SDEIS provides updates to the PHMSA data and information on incidents associated with the existing Keystone Oil Pipeline Project.

Incidents that result in unintentional releases from hazardous liquid pipelines, which includes crude oil pipelines, are reported to PHMSA on standard forms in accordance with 49 CFR 195.50. PHMSA maintains a database of pipeline incident reports (available online at: http://primis.phmsa.dot.gov/comm/reports/safety/psi.html). Pipeline incident reports encompass onshore and offshore natural gas and hazardous liquid pipelines. In addition to crude oil pipelines, hazardous liquid pipelines include pipelines that transport oil products, liquefied petroleum gas (LPG), anhydrous ammonia, and other hazardous liquids.

The PHMSA database of hazardous liquid pipeline incidents includes incidents categorized as "significant." Significant hazardous liquid pipeline safety incidents include those that meet one or more of the following criteria:

- Spills releasing 2,100 gallons (50 barrels [bbl])[9] or more;
- Spills of 210 gallons (5 bbl) of highly volatile liquid[10];
- Spills resulting in total costs of $50,000 or more (1984 dollars);
- Spills that result in unintentional fire or explosion; or
- Incidents involving a fatality or an injury requiring in-patient hospitalization.

PHMSA defines a "serious" pipeline incident as one that involves a fatality or an injury requiring in-patient hospitalization. As noted above, significant incidents include all serious incidents.

The PHMSA incident database includes summary tables that provide overviews of serious and significant incidents reported over the last 20 years, ending in 2010. Prior to 2002, PHMSA required reports of hazardous liquid releases of greater than or equal to 2,100 gallons (50 bbl). As of 2002, PHMSA required reports of hazardous liquid releases of greater than or equal to 5 gallons (0.1 bbl). Therefore PHMSA data prior to 2002 likely understate the actual number of incidents and lead to over estimates of average spill volumes.

Table 3.13.1-1 presents the average number of serious incidents in a year for hazardous liquid pipeline operators (combined onshore and offshore pipeline incidents). The summary data indicate a decreasing temporal trend in the annual average number of serious pipeline incidents. These data include 93 serious incidents reported for 20 years, from 1991 to 2010.

[9] 1 bbl equals 42 U.S. gallons. Oil volumes are provided in gallons followed by bbl in this EIS.
[10] The statistics include incidents related to highly volatile liquids; however, crude oil is not a highly volatile liquid. Therefore, incident statistics are somewhat overstated when considering incidents involving crude oil pipeline transport.

TABLE 3.13.1-1 Nationwide Onshore and Offshore Hazardous Liquid Pipeline Systems, Annual Averages for Serious Incidents [a]	
Time Period	**Annual Average Serious Incidents per Period**
5-year average (2006–2010)	3
10-year average (2001–2010)	3
20-year average (1991–2010)	5

[a] Incidents involving a fatality or an injury requiring in-patient hospitalization.
Source: PHMSA 2011.

The average number of significant incidents per year for onshore hazardous liquid pipelines from 1991 through 2010 is presented in Table 3.13.1-2 along with other data related to the reported incidents. These summary data indicate a generally decreasing trend in annual incident frequency and injuries. The average gross spill volume for the 20-year period was higher than that of the other periods, likely reflecting the higher level of integrity for newer pipelines and the effects of increasingly stringent regulatory requirements.

A summary of PHMSA significant pipeline safety incidents by cause for the period from 2008 through 2010 for onshore hazardous liquid pipelines is presented in Table 3.13.1-3.

TABLE 3.13.1-2
Nationwide Onshore Hazardous Liquid Pipeline Systems, Annual Averages for Significant Incidents

Period	Number of Incidents	Fatalities	Injuries	Property Damage [b,c]	Gross Barrels Lost	Barrels Recovered	Net Barrels Lost
3-year average (2008 – 2010)	107	2	3	$244,301,451	108,201	33,279	74,922
5-year average (2006–2010)	106	2	4	$171,257,826	110,921	41,665	69,256
10-year average (2001-2010)	114	2	6	$143,814,380	104,065	38,647	65,418
20-year average (1991-2010)	134	2	9	$111,080,000	125,532	55,695	69,837

[a] Incidents include those that meet one or more of the following criteria: spills releasing 2,100 gallons (50 barrels [bbl]) or more; spills of 210 gallons (5 bbl) of highly volatile liquid; spills resulting in total costs of $50,000 or more (1984 dollars); spills that result in unintentional fire or explosion; or an incident that involves a fatality or an injury requiring in-patient hospitalization.

[b] The costs for incidents prior to 2010 are presented in 2010 dollars. Costs were adjusted using the Bureau of Economic Analysis, Government Printing Office inflation values.

[c] For years 2002 and later, property damage is estimated as the sum of all public and private costs reported in the 30-day incident report. For years prior to 2002, accident report forms did not include a breakdown of public and private costs so property damage for these years is the reported total property damage field in the report.

Note: Totals for the period from 1991 through 2010: 2,672 incidents; 40 fatalities; 178 injuries; $2,221,600,007 property damage; 2,510,639 barrels lost; 1,113,894 barrels recovered, and 1,396,745 net barrels lost.

Source: PHMSA 2011.

TABLE 3.13.1-3
Nationwide Onshore Hazardous Liquid Pipeline Systems, Causes of Significant Incidents[a] (2008-2010)

Cause	Number of Incidents	Percent of Total Incidents (%)	Fatalities	Injuries	Property Damage [b, c]	Percent of Property Damage (%)
All other causes	22	6.7	4	1	$526,062,146	69.6
Corrosion	69	21.0	0	0	$38,672,895	5.1
Excavation damage	42	12.8	1	2	$27,382,678	3.6
Incorrect operation	34	10.3	1	6	$7,352,773	0.9
Material or equipment failure	125	38.1	0	0	$104,184,945	13.8
Natural force damage	20	6.1	0	0	$24,049,849	3.1
Other outside force damage	8	2.4	1	1	$5,199,064	0.6
Total[c]	**320**	**97.5**	**7**	**10**	**$732,904,353**	**97.0**

[a] Incidents include those that meet one or more of the following criteria: spills releasing 2,100 gallons (50 barrels [bbl]) or more; spills of 210 gallons (5 bbl) of highly volatile liquid; spills resulting in total costs of $50,000 or more (1984 dollars); spills that result in unintentional fire or explosion; or an incident that involves a fatality or an injury requiring in-patient hospitalization.

[b] The costs for incidents prior to 2010 are presented in 2010 dollars. Costs were adjusted using the Bureau of Economic Analysis, Government Printing Office inflation values.

[c] Property damage was estimated as the sum of all public and private costs reported in the 30-day incident report, adjusted to 2010 dollars.

[c] Totals presented as reported by PHMSA.

Source: PHMSA 2011.

Outside forces incidents listed in Table 3.13.1-3 include: excavation damage from mechanical equipment, such as bulldozers and backhoes (12.8 percent); natural force damage, including earth movements due to soil settlement, washouts, or geologic hazards and weather effects such as winds, storms, and thermal strains (6.1 percent); and other outside force damage (2.4 percent). Older pipelines have a higher frequency of outside force incidents partly because their location may be less well known and less well marked than it is for newer lines. In addition, the older pipelines contain a disproportionate number of smaller diameter pipes with reduced wall thicknesses, and have a greater rate of incidents related to outside forces. These pipelines are more easily crushed or broken by mechanical equipment or earth movements than larger diameter pipelines such as that of the proposed Project.

Corrosion was the reported cause of 21 percent of all hazardous liquid pipeline incidents from 2008 through 2010 (Table 3.13.1-3). The frequency of incidents is strongly dependent on pipeline age. Older pipelines have a higher frequency of corrosion incidents, because corrosion is a time-dependent process. Also, new pipe generally uses more advanced coatings and cathodic protection to reduce corrosion potential. Significant improvements in corrosion control technology applied to pipelines installed since the 1950s have resulted in reduced corrosion-related incident frequencies. Accordingly, the oldest pipelines (pre-1950) experience a disproportionate frequency of corrosion-related failures (Keifner and Trench 2001). In contrast, the proposed Project would incorporate state-of-the-practice corrosion control methods based on current industry standards, current PHMSA requirements, and the set of Project-specific Special Conditions developed by PHMSA and incorporated into the proposed Project plan (see Sections 2.3 and 3.13.4.5).

It is important to consider pipeline age when assessing risk based on records of incident frequencies. In 2004, the Transportation Research Board (TRB 2004) published a review of pipelines that included "Pipeline Safety Data and Trends" as an appendix. Appendix B of that report summarizes a detailed analysis of API and USDOT hazardous liquid pipeline incident data, and relies heavily on previous work done for API (Keifner and Trench 2001). The API work confirms that hazardous liquid pipeline age is a significant spill risk factor, for various reasons. The study grouped pipelines by decade of construction. The work shows that older pipelines not only experienced a higher frequency of spill incidents in general, but they also experienced a higher frequency of spill incidents due to third-party damage.

Many industry standards and practices, PHMSA regulatory requirements, and the set of Project-specific Special Conditions developed by PHMSA that would be incorporated into the proposed Project would likely reduce the potential for spill incidents associated with the proposed Project as compared to PHMSAs incident data summaries (see Sections 2.3 and 3.13.1, and Appendix C of this SDEIS for additional details).

TransCanada and Keystone Operating History

For much of its history, TransCanada's business operations focused on natural gas transportation systems in Canada and the United States. In February 1996, the firm initiated its oil transportation business with a 50/50 joint venture with Alberta Energy Company (now EnCana Corporation) to purchase the Platte pipeline and to construct the Express pipeline later that year. Together, the Express and Platte pipelines constitute a 1,700-mile system between Hardesty, Alberta and Wood River, Illinois. The system became operational in February 1997, with commercial deliveries beginning in April 1997. Alberta Energy Company operated the Express and Platte systems on behalf of the joint venture partnership until October 2000, when TransCanada divested its 50 percent interest to EnCana Corporation.

Keystone, a TransCanada subsidiary, constructed the Keystone Oil Pipeline Project (Keystone Mainline Pipeline and Cushing Extension) and the mainline portion of that system initiated operation in 2010. As a

result, TransCanada's limited operating history with crude oil pipelines precludes a direct comparison of accident and oil spill incident rates specific to TransCanada with the industry average rates.

During pre-startup testing and initial operation of the Keystone Oil Pipeline Project, there were six unintentional releases of crude oil: five occurred at pump stations and one occurred at an MLV. All of the releases resulted from failures of fittings or seals and all of the releases were contained within the confines of the pump station or MLV site. Although most of the releases were not large enough to require reporting, all six of the spills were reported. The reported incidents through January 8, 2011 included the following:

- May 21, 2010: less than 5 gallons (0.1 bbl) spilled at Carpenter Pump Station in Clark County, South Dakota;
- June 23, 2010: less than 100 gallons (2.4 bbl) spilled at Roswell Pump Station in Miner County, South Dakota;
- August 10, 2010: less than 2 gallons (0.05 bbl) spilled at Freeman Pump Station in Hutchinson County, South Dakota;
- August 19, 2010: 10 gallons (0.2 bbl) spilled at Hartington Pump Station in Cedar County, Nebraska;
- January 5, 2011: less than 2 gallons (0.05 bbl) spilled at Ferney Pump Station in Day County, South Dakota; and
- January 8, 2011: less than 3 gallons (0.07 bbl) spilled at an MLV in Doniphan County, Kansas.

For each incident, the crude oil was discovered soon after the release occurred and cleaned up immediately after discovery. No environmental damage was reported.

To evaluate TransCanada's experience in operating gas transmission pipelines, a review of PHMSA enforcement actions was conducted on all of the natural gas pipelines it operated in the U.S. The pipelines reviewed, with dates TransCanada assumed control of the assets, are listed below:

- Gas Transmission Northwest Corp. – Operator ID # 15014 – November 2, 2004;
- ANR Pipeline Co. – Operator ID # 405 – February 22, 2007;
- Great Lakes Gas Transmission Co. – Operator ID # 6660 – February 22, 2007;
- Northern Border Pipeline Company – Operator ID # 13769 – April 1, 2007;
- Tuscarora Gas Transmission Co. – Operator ID # 30838 – December 19, 2006;
- Portland Natural Gas Transmission – Operator ID # 31145 – August 3, 2004; and
- North Baja Pipeline – Operator ID # 31891 – November 2, 2004.

For these pipelines, PHMSA identified two 49 CFR Part 192 compliance issues (natural gas) from time of pipeline ownership to December 31, 2009. There were no civil penalties imposed, and all past compliance issues have been resolved with TransCanada and closed by PHMSA.

3.13.2 Spill Volume Categories and Potential Types of Releases

3.13.2.1 Spill Volume Categories

To address potential spills from the proposed Project in this EIS, the following categories of spill volumes were used:

- Very small spills: less than 210 gallons (less than 5 bbl);
- Small spills: 210 to 2,100 gallons (5 to 49.9 bbl);
- Substantive spills: 2,100 to 21,000 gallons (50 to 499.9 bbl);
- Large spills: 21,000 to 210,000 gallons (500 to 5,000 bbl); and
- Very large spills: greater than 210,000 gallons (5,000 bbl).

This size classification is generally similar to the unofficial categories used by PHMSA for spill reporting. The very small spill and very large spill categories were added to facilitate discussion of the majority of spills (less than 210 gallons [5 bbl]) and very rare spills (greater than 210,000 gallons [5,000 bbl]). A range of spill scenarios was assessed to facilitate the impact assessment. Spill scenarios were based on these spill volume categories. Over the past 20 years (from 1990 through 2010), the average spill size in the PHMSA significant incident database for onshore hazardous liquid pipelines was less than 42,000 gallons (1,000 bbl).

Very Small and Small Spills

The most common scenarios are the very small (less than 210 gallons [5 bbl]) and small (210 to 2,100 gallons [5 to 49.9 bbl]) spills of material—usually diesel, hydraulic fluid, transmission oil, or antifreeze—on work pads, roads, and facility parking or work areas. Some of these small spills may result from slow and small (pin hole) leaks of crude oil from the proposed pipeline, or spills during maintenance activities on the pipeline and its facilities (e.g., pump station valves).

Substantive and Large Spills

Substantive (2,100 to 21,000 gallons [50 to 499.9 bbl]) and large (21,000 to 210,000 gallons [500 to 5,000 bbl]) spills would be much less likely to occur than smaller sized spills (see Sections 3.13.2, 3.13.3, and 3.13.4). Large spills would more likely be crude oil releases from the proposed pipeline and would likely occur in the ROW. Both Substantive and large spills could result from tanker truck accidents (during construction), major failure of the fuel storage tanks at construction sites, outside forces such as excavators and major earth movement, or corrosion of the pipe.

Very Large Spills

A very large spill (greater than 210,000 gallons [5,000 bbl]) could occur during operation and could result from either (1) a major rupture or a complete break in the proposed pipeline, or (2) from a failure of one or more of the three, 350,000-bbl crude oil storage tanks at the Cushing tank farm and the concurrent failure of the containment berms surrounding the tanks. As discussed in Section 3.13.4.2, a very large spill from the pipeline would likely require the occurrence of an event that would shear the pipeline such as major earth movement resulting from slides, major earth movement resulting from an earthquake, major flood flows eroding river banks at non-HDD crossings, mechanical damage from third-party excavation or drilling work, or vandalism, sabotage, or terrorist actions.

3.13.2.2 Potential Types of Releases

The following sub sections provide summary information on the types of materials that may be released from the proposed Project during construction and operation. More detailed information, particularly on crude oil, is presented in Section 3.13.5.1.

Refined Oil Products

Release volumes of refined oil products (e.g., gasoline, diesel, and lubricating and hydraulic fluids) during proposed Project construction or operations would typically be very small to small, although larger release volumes are possible. The small to very small releases would typically be associated with equipment fueling and hydraulic fluid line ruptures. These spills would most likely occur at the construction or operation/maintenance sites, at fueling stations, on the roadways, within the ROW, and at similar managed locations where they would be readily contained and remediated. Refined product releases could also result from accidents (e.g., tank truck rollover); excess fuel or lubricants during vehicle, equipment, and machinery maintenance; failure of fuel storage tanks and the surrounding containment berms; and incorrect operation of equipment or fueling procedures.

Hazardous Materials

The volume of hazardous materials that would be used during proposed Project construction and operations would be small and therefore any spills would likely be very small to small with little likelihood of a Substantive spill. Any hazardous material spills would most likely occur at the construction or operation/maintenance sites where materials would be stored in containers that define maximum spill quantities. Implementation of the ERP, SPCC plans, and hazardous materials location restrictions (see the CMR Plan in Appendix B of the draft EIS) would reduce the risk that a hazardous material release could affect surface waters.

Crude Oil

Crude oil releases could occur during proposed Project operation and maintenance activities, as discussed in Section 3.13.4. Estimates of potential crude oil spill volumes are presented in those sections and in Appendix P of the draft EIS. The characteristics of the crude oil that would be transported by the proposed Project are discussed in Sections 3.13.5.1 and 3.13.5.3.

3.13.3 Potential Releases during Project Construction

Most construction-related spills would likely release minor quantities of refined products (e.g., gasoline, diesel, and lubricating and hydraulic fluids). These releases would be subject to the reporting requirements of 40 CFR Part 110, and would typically result from vehicle and construction equipment fueling and maintenance. Contractor construction staging and pipe storage areas would typically include skid-mounted, aboveground gasoline storage tanks (9,500-gallon [226-bbl] capacity) and diesel storage tanks (10,000-gallon [238-bbl] storage capacity). These fuel tanks would be installed within impermeable containment areas to prevent spilled material from reaching adjacent natural habitats. According to the Pipeline Risk Assessment (Appendix P of the draft EIS) and in compliance with one of the requirements of 40 CFR Part 112 for each staging area, oil storage tanks would have secondary means of containment (berms) for 110 percent of the capacity of the largest tank. In addition, portable oil storage containers would have berms that hold 110 percent of the total capacity of the containers inside the berm. Lubricating oil may also be stored in tanks in these areas. Construction would also involve fuel delivery by tanker trucks to operating equipment along the construction ROW. The potential maximum spill volume from the failure of the maximum size fuel tank truck would be about 9,000 gallons (214 bbl) for

diesel or gasoline. Lubricating or hydraulic fluid would be stored in 55-gallon (1.3-bbl) drums, with up to six drums on a pallet. Thus, the potential maximum spill volume of lubricating oil or hydraulic fluid would be equal to the volume of six drums, or approximately 330 gallons (7.9 bbl). Hydrostatic testing of the pipeline prior to operation would not result in release of oil to the environment as the water used in the testing does not contain oil. Also, the discharged water would be required to meet NPDES discharge permit conditions (see Section 2.3.2.6).

Potential spills from construction activities would be addressed by specific preventive and mitigating measures included in the SPCC Plan described in more detail in section 2.3 and Appendix C of the draft EIS.

3.13.4 Potential Spills from Project Operations (Including Maintenance)

3.13.4.1 Operational Spills

Operational spills from the proposed Project could originate from the pipeline, pump stations, MLVs, delivery points, or the Cushing tank farm. Additionally, spills similar to those described for construction could occur as a result of ongoing maintenance activities. As described in Appendix P of the draft EIS, releases from the proposed Project could result from the effects of corrosion (external or internal), excavation or other subsurface equipment disturbance damage, defects in materials or defects related to proposed Project construction, hydraulic over-pressuring related to incorrect operating procedures, or geologic hazards (e.g., ground movement, washouts, and flooding). Although leak detection systems (see Section 3.13.5.5 and Appendix P of the draft EIS) would be in place, some slow leaks might not be detected by the system for an extended period of time. A pinhole leak could be undetected for days or a few weeks if the release volume rate were small and in a remote area. However, although the total volume of a release from a pin hole leak could be relatively large (e.g., up to a substantive spill), in most cases the oil would likely remain within or near the pipeline trench where it could be contained and cleaned up after discovery. Detection would likely occur through visual or olfactory identification, either during regular pipeline aerial inspections, ground patrols, or landowner or citizen observation, in most cases before the release of a substantive volume of oil to surface habitats and environment.

Larger spills would most likely be associated with leak sources other than pinhole leaks (e.g., excavation damage and geologic hazards). In larger spills, some of the released oil could be contained in the immediate vicinity of the release point, although the released oil would likely migrate from the release source. However, experience gained from previous large pipeline oil releases suggests that the distance the oil would likely migrate is limited (see Section 3.13.6.4). Prior to PHMSA granting permission to operate the proposed Project, Keystone would be required to prepare and implement an ERP that would guide response actions in the event of an oil release to facilitate rapid response. Nonetheless, actual response with containment equipment and cleanup crews could be delayed due to one or more of the following factors:

- If the leak is at a remote location, visual leak detection could be difficult and reporting could be delayed;
- Locating the leak could require time searching the release area to determine where the leak originates;
- Snow, darkness, or other natural factors could hinder visual detection;
- Weather conditions, natural disasters (e.g., floods, landslides, excessive snow fall, or drifting) could delay access to the spill location, especially for larger equipment and supply vehicles; and

- Depending on spill volume, proximity, and season, the oil could reach wetlands, freshwater ponds and lakes, streams, or larger rivers thus necessitating additional time to mobilize response (see Section 3.13.5.1).

3.13.4.2 Operational Spills Risk Assessments

To assess the likelihood of operational releases from the proposed Project, spill risk assessments were conducted. These risk assessments addressed both the potential frequency of operational pipeline releases and the potential volumes of crude oil associated with the releases. The risk analyses for the proposed Project used data derived from the PHMSA incident database for hazardous liquid pipelines, including crude oil pipelines, as described below.

Oil Spill Frequency

Two separate approaches were used to estimate oil spill frequency and potential spill volume:

- DOS related historical significant spill incidents (as defined by PHMSA) and spill volumes to hazardous liquid pipelines mileage, both across the U.S. and within the specific states that would be traversed by the proposed Project, based on the PHMSA hazardous liquid pipeline database (PHMSA 2011). It should be noted that the majority of pipelines in the U.S. included in that database were constructed in the 1970s or earlier and were not necessarily constructed consistent with more recent regulatory requirements.

- Keystone related the incident frequency to historic pipeline releases attributed to specific causative mechanisms and adjusted the frequency for Project-specific design, construction, and operational procedures as well as specific terrain conditions that would be crossed by the proposed Project (Appendix P of the draft EIS). Baseline incident frequencies were adjusted to account for improved technologies and current PHMSA regulations for the proposed Project. The baseline incident frequencies were converted to estimated occurrence intervals for the following six categories of incident causes specific to the proposed Project:

  Corrosion – occurrence interval = one per 3,400 years;

  Excavation damage – occurrence interval = one per 8,200 years;

  Materials and construction – occurrence interval = one per 3,300 years;

  Hydraulic surge – occurrence interval = one per 6,800 years;

  Ground movement – occurrence interval = one per 81,500 years; and

  Flooding and washout – occurrence interval = one per 87,800 years.

Significant Incident Frequency Projections

"Significant incident frequency" is defined as the number of significant incidents (as defined by PHMSA) per mile of pipeline per year. At the time this significant incident frequency analysis was prepared, there were approximately 175,000 miles of hazardous liquid pipelines, both offshore and onshore, in the U.S. That pipeline mileage was divided into the 10-year average of 114 significant incidents per year for onshore hazardous liquid pipelines (PHMSA 2011; see Table 3.13.1-2) to calculate the significant incident frequency factor of 0.0007 incidents per pipeline mile per year for nationwide pipelines.

PHMSA's state-by-state hazardous liquid pipeline incident database was used to generate a Project-specific state-by-state subset of the data. The state-by-state PHMSA data summaries provide the total

miles of hazardous liquid pipelines within the state and the number of significant incidents that occurred for onshore hazardous pipelines during the 10-year period from 2001 through 2010. Analysis of these data also resulted in a frequency of 0.0007 incidents per mile per year for the entire proposed pipeline in spite of the fact that there were relatively small numbers of incidents reported in most of the states that would be crossed by the proposed pipeline.

There are approximately 55,000 miles of crude oil transmission lines in the U.S. (Tribal Energy and Environmental Clearing House 2011, Pipeline 101 2011). The detailed PHMSA incident report database was used to obtain the number of incidents of crude oil spills from onshore hazardous liquid pipelines during the reporting period from 1997 through 2008. There were approximately 600 reported incidents during that 10-year period, which equates to a frequency of 0.00109 crude oil incidents per mile per year.

The results of these three analyses were used to project the number of significant incidents per year for each segment of the proposed Project. The calculated numbers of significant incidents by proposed segment and for the entire proposed pipeline are provided in Table 3.13.4-1.

TABLE 3.13.4-1
Projected Significant Spill Incidents (>50 Barrels) per Year for the Proposed Project Pipeline

Characteristic	Full PHMSA Hazardous Liquids Dataset [a]	PHMSA Data for States Crossed by the Proposed Pipeline [b]	PHMSA Data–Crude Oil [c]
Incidents per mile per year	0.0007	0.0007	0.00109
Proposed Project Segment	**Spill Incidents Per Year**		
Steele City Segment (852 miles)	0.60	0.60	0.93
Cushing Extension (298 miles)	0.21	0.21	0.32
Gulf Coast Segment and Houston Lateral (532 miles)	0.37	0.37	0.58
Project total (1,682 miles)	**1.18**	**1.18**	**1.83**

[a] "Full" includes all hazardous liquid pipelines in the U.S., both onshore and offshore.
[b] Includes data only for onshore hazardous liquid pipelines in the states that would be crossed by the proposed pipeline.
[c] "Crude oil" includes data just for onshore crude oil pipeline incidents, all states.
Source: PHMSA 2009.

Incident Frequency Determined by Specific Causative Mechanisms

Keystone produced a Project-specific spill frequency estimate using an alternative approach (see Appendix P of the draft EIS). This analysis summed spill frequencies by specific pipeline integrity "threats" as defined in ASME B31.8S (i.e., corrosion, excavation, material defects, hydraulic events, ground movements, and washout events) for the entire proposed pipeline, including the existing Cushing Extension. Each threat spill frequency estimate was adjusted as appropriate based on specific state-by-state natural conditions and Project-specific design and operational criteria. The calculations resulted in a spill incident frequency factor of 0.000135 incident per mile per year, which is equivalent to approximately 2.2 spills per 10 years for the entire proposed Project. Summary data from this analysis are presented in Table 3.13.4-2.

TABLE 3.13.4-2 Projected Spill Occurrence for the Proposed Project over a 10-Year Interval	
Proposed Pipeline Segment	**Spills per Segment (rounded)**
Steele City Segment (852 miles)	1.1
Keystone Cushing Extension (298 miles)	0.4
Gulf Coast Segment and Houston Lateral (532 miles)	0.6
Project Total (1,682 miles)	**2.2**

Source: Keystone 2009a.

Results Comparison

The incident frequency analysis based on significant spill incidents as a function of existing pipeline mileage and PHMSA data on significant incidents without adjustments resulted in a spill occurrence estimate that is higher than that produced by the Project-specific analysis in Appendix P of the draft EIS. This is not an unexpected result because the historical database includes releases from much older pipeline systems with routes through different topography and geographic areas and older, less stringent design criteria than those of the proposed Project. With implementation of the USDOT Integrity Management Rule, continually improving industry operating practices, and advancements in pipeline technology the spill frequency for modern pipeline systems would likely be lower than historical levels observed on older pipelines. In fact, hazardous liquid pipeline serious and significant incident frequencies have been steadily decreasing, as indicated by the PHMSA 5-year, 10-year, and 20-year incident frequency averages (Tables 3.13.1-1 and 3.13.1-2). The frequency of oil spills from the proposed pipeline and facilities would likely be lower than the PHMSA data statistical frequency, which reflects past experience.

It is likely that both incident frequency analyses tend to overestimate the likely spill frequency of the proposed Project since both analyses rely on data that include incidents on older pipelines that would not be operated under the Project-specific Special Conditions developed by PHMSA and incorporated into the design, construction, operations, and maintenance plans for the proposed Project.

Oil Spill Volume

Historical Spill Volumes

The 10-year average of PHMSA onshore hazardous liquid pipeline significant incident data (PHMSA 2011) indicates that the average reported gross volume of fluid lost per year from 2001 through 2010 was 4,370,730 gallons (104,065 bbl) per year. This equates to an average fluid loss per pipeline mile per year of approximately 25 gallons (0.6 bbl). Using data for onshore hazardous liquid pipelines for each state that would be crossed by the proposed pipeline, the average loss would be 24.8 gallons (0.6 bbl) per mile per year for the full length of the proposed pipeline. Using the PHMSA database for crude oil spills, the loss rate would be approximately 43.7 gallons (1.04 bbl) per mile per year. The average volume for crude oil spills is likely higher than that for all hazardous liquid pipelines due to the fact that larger crude oil volumes are typically transported by pipeline than volumes of other materials. Using these historical spill volume values applied to the pipeline mileage of the proposed Project, the estimates of spill volumes obtained are:

- 42,050 gallons (1,002 bbl) based on the full PHMSA onshore hazardous liquid pipeline database;

- 31,790 gallons (757 bbl) based on the state-by-state PHMSA onshore hazardous liquid pipeline database; and
- 73,503 gallons (1,750 bbl) based on the PHMSA database specific to onshore crude oil pipelines.

PHMSA data for incidents from 2002 through 2010 indicate that 50 percent of the releases over that time period were 126 gallons (3 bbl) or less and that less than 0.3 percent of those releases were 420,000 gallons (10,000 bbl) or greater (PHMSA 2011). However, PHMSA data also indicate that large to very large pipeline spills do occur.

Maximum Spill Volumes

In response to a data request from PHMSA, Keystone conducted a maximum potential pipeline spill volume assessment. A very large (greater than 210,000 gallons [5,000 bbl]) spill would be a very unlikely event (see Appendix P of the draft EIS) and would likely result from a major rupture or a complete break in the proposed pipeline that releases crude oil somewhere along the ROW. The actual volumes spilled would vary depending on a number of factors, including:

- MLV locations, activation methods, and activation delay times;
- Operating pressure within the pipeline;
- Location of the structural failure;
- Extent to which the proposed pipeline follows topographic contours, and the location of low spots in the pipeline relative to the structural failure; and
- Nature of the structural failure.

A complete structural failure of a 36-inch outer diameter pipeline with the wall thicknesses of the proposed pipeline (see Section 2.3.1, Table 2.3.1-1) would be a highly unlikely event. To cause such a failure, the proposed pipeline would likely need to experience a direct shear event. Such events could be caused by:

- A strike-slip fault movement across the proposed pipeline – however, the proposed pipeline corridor does not cross any known active faults;
- An anchor drag event or a collision event within a navigable river that experiences large to very large ship or barge traffic – however, all such river crossings along the proposed corridor would be crossed using HDD and the pipeline would therefore be installed well below the maximum anchor depth and outside any potential collision hazard;
- A major construction-related accidental equipment interaction with the buried pipeline – however, the proposed pipeline would be buried under a minimum of 4 feet of cover, would be clearly marked, would include warning tape (ribbons) as required by the Project-specific Special Conditions developed by PHMSA, would be predominantly routed through rural areas where such large equipment construction impacts would be rare, and Keystone would implement public awareness and damage prevention programs in accordance with 49 CFR 195.440 and API RP 1162;
- An intentional act of sabotage, vandalism, or terrorism – however, the pipeline would be buried with a minimum of 4 feet of cover and all aboveground facilities would include security fencing, thus reducing facility accessibility to these potential threats;

- A major flood event with the potential to cause deep scour and debris impact to the proposed pipeline – however, at major river crossings, the proposed pipeline would be installed using HDD and would therefore be below the maximum scour depth, and at all stream crossings, the proposed pipeline would be installed below the calculated scour depth;
- A major slide event could be possible in steep slope areas along the proposed pipeline corridor – however, Keystone has considered landslide potential in the routing of the proposed pipeline and has selected crossings of steeper slope areas where the landslide potential is considered minimal, and the potential for landslide activity would be monitored during operations through regular aerial and intermittent ground patrols and through landowner awareness programs; or
- A combination of a high level of corrosion with some external force on the proposed pipeline – however, the proposed pipeline would be designed, constructed and operated consistent with the requirements of 49 CFR 195 and the Project-specific Special Conditions developed by PHMSA (see Appendix C of this SDEIS), many of which address requirements to reduce and monitor corrosion throughout the lifetime of the proposed Project. Some commenters expressed concern that WCSB crude oil pipeline statistics from Canada suggest that corrosion rates for WCSB crude oil pipelines are higher than for other crude oil pipelines. Direct comparisons between spill frequencies in the Canadian NEB/ERCB incident database and the PHMSA spill frequency database are complicated by differences in spill reporting requirements in the two jurisdictions. In Canada, spills of any size are reported. In the U.S., spills of 5 barrels or more are reported at this time. However, it is noted that PHMSA reported that in the U.S. from 2002 to 2009 internal corrosion accounted for approximately 26.5 percent of spill incidents (PHMSA 2011). The NEB/ERCB reported that in Alberta from 1990 to 2005 internal corrosion accounted for approximately 24.8 percent of spill incidents (Alberta Energy and Utilities Board 2007).

To ascertain what the maximum volume release could be at any location along the proposed pipeline corridor as requested by PHMSA, an analysis was conducted that assessed maximum leak volume from a complete pipeline structural failure within every 3-foot-long segment of the proposed pipeline corridor. This analysis used the following response times:

- Stop pumping units at all pump station locations: approximately 9 minutes;
- Close remotely operated isolation valves: approximately 3 minutes;
- Total time: approximately 12 minutes.

The analysis also assumed a complete pipeline shear and draindown, a highly unlikely event for the reasons stated above. The analysis considered the configuration of the pipeline and the location of MLVs and pump stations relative to each 3-foot-long segment from the Canadian border to delivery terminals. Based on this analysis, the approximate maximum spill volume was estimated to be approximately 2.8 million gallons (66,500 bbl), and it was determined that this size release was only theoretically possible along less than 0.1 percent of the proposed pipeline route (less than 1.7 miles). It is important to note that this approximate maximum spill volume could not occur at all locations along the proposed pipeline corridor. It represents the release that would occur under a structural failure scenario where the distance between MLVs and the terrain gradient in the vicinity of the failure, in combination with other factors, would lead to a maximum draindown condition. At all other locations along the pipeline corridor, the maximum draindown volume would be lower. For approximately 50 percent of the proposed pipeline corridor (approximately 842 miles), the modeled maximum spill volume would be less than 672,000 gallons (16,000 bbl) due to a complete structural failure of the pipeline. For the rest of the pipeline, the maximum release would be less due to topography and MLV placement. Areas where maximum spill volumes would be much lower include river crossings and pump stations where MLVs occur on each side of the river or the pump station.

In summary, the estimates of maximum spill volume were based on an analysis that included the following assumptions:

- Complete structural failure of the pipeline;
- Maximum assumed time between the failure incident and the time of detection;
- Maximum time for shutdown to be initiated and completed;
- Maximum flow rate; and
- Largest potential line drainage volume between the closest MLV on each side of the structural failure given site conditions at each 3-foot segment.

To put the size of these maximum spill estimates into perspective, they can be compared to the size of major historical pipeline oil spills. The largest major historical pipeline spills in the U.S. from 1979 through 2010 ranged from about 300,000 to 1.3 million gallons (7,143 to 30,950 bbl). In this time period, there were less than 10 spills within this range of magnitudes. These spills were all lower in volume than the potential largest spill from the proposed pipeline and they appear to confirm the conservatism in the maximum spill estimates, given that they occurred in pipeline systems much older and designed to less stringent requirements than the proposed Project, although none of the pipelines involved with these spills were of the same pipeline diameter and operating pressure as those of the proposed Project.

A very large spill could occur at the proposed Cushing tank farm. However, each of the three 350,000-bbl tanks would be surrounded by a secondary containment berm (Section 2.2.6) that would hold 110 percent of the contents of the tank plus freeboard for precipitation. Therefore, a very large release to the environment could only occur in the unlikely event of a major failure of a tank and a concurrent failure of the secondary containment berm. All other releases from tank failure would be contained within the bermed areas.

3.13.5 Impacts Related to Oil Spills

Crude oil released from the proposed pipeline during operations or refined oil released during construction or operations into the environment may affect natural resources, protected areas, human uses and services, and aesthetics to varying degrees, depending on the cause, size, type, volume, location, season, environmental conditions, and depending on the timing and degree of response actions. Small oil spills (e.g., minor intermittent leaks and drips from construction machinery and operating equipment) would be almost certain to occur during construction and operation of the proposed Project, although in aggregate these spills could be of sufficient magnitude to substantively affect natural resources and human uses of the environment.

Most oil spills are only broadly predictable in cause, location, time of occurrence, size, and duration (J.L. Mach et al., Hart Associates, Inc. 2000). For example, it is more likely that:

- A pipeline spill would occur in a populated area where excavation is a frequent activity than in a remote wilderness area;
- A pipeline washout would occur in a major river bed than in a small creek;
- A fueling spill would occur on a fueling station pad than on the ROW; or
- A tanker truck would overturn on a winding mountain road than on the prairie.

When an oil spill occurs, the resulting environmental impact depends on a number of factors, including:

- Amount and duration of oil release, and location with respect to topography, infrastructure, and sensitive receptors;
- Fate and behavior of the spilled oil (i.e., the potential for a spill reaching an environmental receptor and its persistence in the environment);
- Chemical composition and physical characteristics of the oil; and
- Toxicity and other adverse effects of the oil to the receptors.

The oil spill literature is diverse, extensive, and often presents conflicting results and conclusions regarding acute and chronic impacts from oil spills. Much of the literature is not published in the peer-reviewed literature but consists of technical reports prepared by the potentially responsible parties (PRPs), natural resource trustees (e.g., state, federal, and tribal managers for the natural resources), consultants and academics retained by the PRPs and/or Trustees, and other interested parties including NGOs. Nevertheless, the body of literature and information taken together provides a basis for evaluating the potential range of impacts that may result from an oil spill from the construction, operation, maintenance and demobilization of the proposed pipeline. Some of the sources of the information utilized for this analysis include the following:

- NOAA DARP website where the Damage Assessment and Restoration Plans provide a description of oil spill impacts as well as planned restoration actions (www.darrp.noaa.gov);
- USFWS website where impact assessment and restoration plans are provided for a limited number of sites (www.fws.gov/contaminants/restorationplans/plans.cfm);
- Oil and Nature Bulletin by USFWS (www.fws.gov/contaminants/Documents/OilAndNature.pdf);
- Resources on Oil Spills, Response, and Restoration: A Selected Bibliography by Anna Fiolek, Linda Pikula, and Brian Voss. June 2010. National Oceanic and Atmospheric Administration, Library and Information Services Division. (http://docs.lib.noaa.gov/noaa_documents/NESDIS/NODC/LISD/Central_Library/current_references/current_references_2010-2.pdf);
- Damage Assessment and Restoration Plan/Environmental Assessment (DARP/EA) listing by California for several Natural Resource Damage Assessments (NRDAs) (www.dfg.ca.gov/ospr/NRDA);
- Oil spill response in freshwater: Assessment of the impact of cleanup as a management tool by John H. Vandermeulen and Cal W. Ross in Journal of Environmental Management 44(4):297-308, 1995;
- Environment Canada's website (www.ec.gc.ca/scitech/) that provides access to 34 years of publications on oil spill impacts and response (mostly in temperate to cold environments) that have been presented at the annual AMOP Technical Seminar on Environmental Contamination and Response;
- Archived Proceedings of the International Oil Spill Conference (www.iosc.org/papers/search.asp) wherein many papers and posters deal with the fate of oil in freshwater systems as well as the impacts to natural resources; and
- Additional papers, technical reports, Natural Resource Damage Assessments (NRDAs) books, and bibliographies related to freshwater oil spill impacts that provide detailed (and sometimes contradictory) assessments of impacts as well as the recovery of natural resources from oil spills,

including many catalogued and/or prepared by EPA, USFWS, NOAA, USCG, and many state agencies.

A discussion of oil spill impacts requires a depiction of typical potential spill scenarios and environmental variables that might affect spilled oil fate and behavior. These depictions are necessarily simplified and do not represent the entire spectrum of events that might be realized in actual spills. However, many of these factors and assumptions have been used in previous similar assessments, and all are based on the peer-reviewed literature, technical reports, and empirical experience of oil spill experts worldwide. The following key factors are addressed below:

- Physical, Temporal and Environmental Factors Affecting Hazardous Liquid Spill Impacts (Section 3.13.5.1);
- Keystone Response Time and Actions (Section 3.13.5.2);
- Factors Affecting the Behavior and Fate of Spilled Oil (Section 3.13.5.3);
- Summary of Environmental Factors Affecting Fate of Spilled Oil (Section 3.13.5.4);
- Keystone Actions to Prevent, Detect, and Mitigate Oil Spills (Section 3.13.5.5);
- Types of spill impacts (Section 3.13.5.6).

3.13.5.1 Physical, Temporal, and Environmental Factors Affecting Hazardous Liquid Spill Impacts

Impacts related to hazardous liquid spills could be affected by the release location, type and volume of material released, nearby receptors and resource uses, seasonal variations, weather, water levels, and other factors that are described below.

Location of Spill

Most spills would occur and be contained within or in close association with the proposed pipeline ROW or associated infrastructure, including construction yards, pump stations, and maintenance yards. These spills would typically be very small (less than 42 gallons [1 bbl]) and would likely be promptly cleaned up as required by federal, state, and local regulations. During construction, some refined product spills may occur from tank truck accidents along roads leading to the construction sites. Some of these spills may result in much or all of a load being spilled to the land, wetlands, ponds and lakes, or flowing waterbodies adjacent to the road or pad. The maximum volume of gasoline or diesel from a tank trunk would be about 9,000 gallons (214 bbl) for diesel or gasoline and approximately 330 gallons (7.9 bbl) for lubricating or hydraulic fluid (i.e., six 55-gallon drums on a pallet). These spills would likely have limited areal extent unless they occurred at or very near an open water body.

Spills during operation and maintenance of the proposed pipeline would for the most part involve crude oil. Based on experience, spills resulting from excavation damage would likely occur in urban/suburban areas and some agricultural areas where water-conveying canal excavation activities below four feet of depth are common. The locations of greatest concern for potential oil spills would be those that are up-gradient of HCAs, especially water intakes for public drinking water or commercial/industrial users and USAs, especially wetlands, flowing streams and rivers, and similar critical habitats.

Type of Material Released

As stated previously, throughout construction operation and maintenance of the proposed Project, it would be possible to spill refined oil products, hazardous materials and crude oil. This EIS focuses on crude oil because of the potential for large-to very large volume releases of crude oil into sensitive areas over the approximately 1,682-mile-long proposed pipeline route.

Crude oil transported by the proposed Project would, for the most part, originate within the Alberta oil sands. The material extracted from the oil sands is typically a very viscous material called bitumen. Bitumen and the types of crude oils produced through either processing or converting the bitumen are defined as follows:

- *Raw bitumen* – Raw bitumen is solid under ambient conditions and therefore must be diluted or converted prior to transport via pipeline.
- *Upgraded bitumen (SCO or syncrude)* – SCO (synthetic crude oil) is produced from bitumen via a refinery conversion that turns heavy hydrocarbons into lighter hydrocarbons. While SCO can be sour, it is usually a light, sweet crude without heavy fractions.
- *Diluted bitumen (dilbit)* – Dilbit is bitumen mixed with a diluent, usually a natural gas liquid such as condensate. This is done to make the mixed product "lighter," reducing viscosity so the dilbit can be transported via pipeline. Dilbit feedstock processing requires more heavy oil conversion capacity than most crude oils and it is considered lower quality than most crude oils with its high levels of sulfur and aromatics.
- *Synthetic bitumen (synbit)* – Synbit is usually a combination of bitumen and SCO. The properties of synbit blends vary greatly, but blending lighter SCO with heavier bitumen results in a product more similar to conventional crude oil than SCO or dilbit alone.
- *Diluted synthetic bitumen (dilsynbit)* – Dilsynbit is a combination of bitumen and heavy conventional crudes blended with condensate and SCO, producing a product more similar to conventional crude oil than SCO or dilbit (IHS CERA 2010).

According to Keystone, the types of WCSB crude oil that would be transported by the proposed Project would primarily consist of SCO and dilbit. The upgrading process for SCO and the addition of diluent in dilbit would occur before the oil would be delivered to the Keystone pipeline at Hardisty, Alberta. The precise composition of SCO and dilbit would vary by shipper and is considered proprietary information. In general, these crude oils would be similar to Western Canada Select (a heavy crude oil) and Suncor Synthetic A (a lighter crude oil). The physical and chemical composition characteristics of these two types of crude oil, as well as several other crude oils derived from the oil sands, are available at http:/www.crudemonitor.ca/assays.html and are further described below.

The diluents used are generally similar to kerosene, natural gas condensate or synthetic crude oil; however, the exact composition may vary between shippers and is considered proprietary information (as is the exact composition of the crude oil). The diluents are integrally combined into the crude oil and would not physically separate if the oil is accidentally released. Over time, the aromatic fraction of any crude oil released to the environment would tend to evaporate, and the water-soluble fraction would tend to enter surface and/or groundwater, if there is any such water in contact with the spilled oil plume. SCO and dilbit would behave in a similar manner if released to the environment. While the raw bitumen produced from the WCSB oil sands is more dense than water, the specific gravity of the crude oils that would be transported on the proposed pipeline ranges from about 0.85 to about 0.93, less than the specific gravity of water. These crude oils, therefore, tend to float on water and would not initially sink if released to an aqueous environment, either at the surface or in the ground.

Crude oils may differ in their solubility, toxicity, persistence, and other properties that affect their impact on the environment. The effects of a specific crude oil are a function of its composition and physical properties. Of particular importance are:

- Specific gravity, which determines whether the unweathered oil would sink or float upon release to an aquatic environment. A specific gravity of less than 1.0 means the unweathered oil will float on fresh water.
- Viscosity, which determines how readily the oil would flow when released, especially in an area with a down slope or downcurrent gradient to an HCA or USA. Typically, viscosity increases as temperature decreases. This may be an important consideration, as air temperatures along the length of the proposed pipeline corridor may range from well below freezing in winter to in excess of 100˚F in summer.
- Pour point, an indicator of the temperature at which the oil changes from liquid to a "solid" material that does not flow.
- Proportion of volatile and semi-volatile fractions, an indicator of (1) the amount of oil that would evaporate or volatilize; (2) the amount of oil that would likely physically persist in the environment as it weathers; and (3) the amount of potentially toxic material that could dissolve or disperse into an aquatic environment and cause toxicological impacts.
- Proportion and amount of polycyclic aromatic hydrocarbons (PAHs), many of which are considered the key toxic fraction of oils.
- Proportion of other elements and compounds including sulfur and metals.

Information on example crude oils expected to be transported by the proposed Project (see Tables 3.13.5-1 and 3.13.5-2) indicates that the transported crude oil would likely have the following general characteristics:

- Average relative density (specific gravity) of approximately 0.846 for Suncor Synthetic A oil and approximately 0.924 for Western Canadian Select crude oil which means that both types of crude oil would float on fresh water;
- Pour point for heavy crude oil less than approximately -30˚C (-22˚F);
- Pour point for synthetic crude oil less than approximately -21˚C (-5.8˚F);
- PAH concentrations which are unknown to Keystone at this time and will be proprietary information with the supplier;
- Benzene, toluene, ethyl benzene, and xylenes (BTEX) concentrations are approximately 1 percent by volume of the crude oil volume;
- Sulfur concentrations less than 0.25 percent and 3.6 percent by weight for synthetic and diluted bitumen respectively;
- Nickel concentrations less than 2.5 and 66 parts per million (ppm) for synthetic oil and diluted bitumen respectively, and vanadium concentrations are less than 160 and less than 4 ppm respectively; and
- Average mercury concentrations for WCSB crude oils are lower than comparable values for Mexican Maya and Venezuelan heavy sour crude oils (see Table 3.13.5-3).

TABLE 3.13.5-1 Constituents and Properties of Western Canadian Select Crude Oil			
Characteristic	**Observed**	**Past Average**	**Standard Deviations [a]**
Basic Properties			
Relative Density	0.924	0.931	0.005
API Density	21.6	20.6	0.8
Absolute Density (kg/m^3)	923.6	929.6	4.8
Total Sulphur (wt %)	3.37	3.33	0.17
MCR (mass %)	8.93	9.38	0.39
SW (vol %)	- [b]	-	-
Sediment (ppmw)	301	374	97
TAN	1.03	0.86	0.11
Salt in Crude (ptb)	-	40.3	12.6
Iron (mg/L)	-	-	-
Nickel (mg/L)	53.6	53.7	6.1
Vanadium (mg/L)	129.9	130.1	13.2
Molybdenum (mg/L)	-	-	-
Constituent			
Methane	-	-	-
Ethane	-	0.03	0.00
Propane	0.07	0.07	0.02
isoButane	0.57	0.59	0.13
nButane	1.54	1.45	0.26
Total Butanes	2.11	2.04	0.38
Total C4 minus	2.18	2.14	0.40
isoPentane	2.14	1.93	0.29
n-Pentane	2.22	2.01	0.30
Hexanes	4.04	3.58	0.54
C7 Paraffins	0.73	0.64	0.10
C7 Naphthenes	1.16	1.10	0.13
C7 Aromatics	0.40	0.34	0.05
nHeptane	0.62	0.56	0.07
Total Heptanes	2.90	2.65	0.30
C8 Paraffins	0.76	0.74	0.09
C8 Naphthenes	0.61	0.63	0.09
C8 Aromatics	0.48	0.44	0.07
nOctane	0.39	0.38	0.05
Total Octanes	2.25	2.79	0.27
C9 Paraffins	0.35	0.36	0.06
C9 Naphthenes	0.38	0.39	0.06
C9 Aromatics	0.68	0.66	0.10
nNonane	0.26	0.23	0.04
Total Nonanes	1.33	1.64	0.23
C10 Paraffins	0.53	0.49	0.07
C10 Naphthenes	0.05	0.06	0.03
C10 Aromatics	-	-	-
nDecane	0.26	0.24	0.05
Total Decanes	0.84	0.78	0.13

TABLE 3.13.5-1 Constituents and Properties of Western Canadian Select Crude Oil			
Characteristic	**Observed**	**Past Average**	**Standard Deviations [a]**
Distillation Information (ºC), % Off			
IBP	-	34.1	1.2
1%	-	35.0	1.7
5%	-	77.2	24.2
10%	-	157.6	35.5
15%	-	222.4	29.2
20%	-	267.5	21.7
25%	-	302.7	18.9
30%	-	333.8	18.3
35%	-	363.9	19.2
40%	-	394.1	20.7
45%	-	423.2	21.5
50%	-	452.3	23.8
55%	-	483.6	26.9
60%	-	518.1	31.1
65%	-	555.7	35.4
70%	-	594.6	37.4
75%	-	633.0	37.8
80%	-	665.7	35.1
85%	-	682.9	28.9
90%	-	698.2	22.1
95%	-	706.6	10.2
98%	-	-	-
99%	-	-	-
100%	-	-	-
FBP	-	716.8	2.5
Residue (%)	-	13.72	4.93
Yield on Crude (Vol %)			
C4 and lighter (mass %)	2.2	2.1	0.4
Naphtha (C5; 190°C)	-	9.1	2.8
Kerosene (190°C – 227°C)	-	10.9	1.2
Distillate (277°C – 343°C)	-	9.7	1.2
Gas Oil (343°C – 565°C)	-	34.7	2.7
Residue (565°C +)	-	33.4	4.8
BTEX (Vol %)			
Benzene	0.18	0.15	0.02
Toluene	0.32	0.27	0.04
EthylBenzene	0.06	0.06	0.01
Xylenes	0.33	0.30	0.05

[a] Past Average and Standard Deviations include 156 records.
[b] - (dash) indicates a tested value below the instrument threshold.
kg/m^3 = kilogram per square meter; wt = weight; vol = volume; mg/L = milligram per liter
Source: Crude Quality Inc. 2010.

TABLE 3.13.5-2 Constituents and Properties of Suncor Synthetic A Crude Oil			
Characteristic	**Observed**	**Past Average**	**Standard Deviations [a]**
Basic Analysis Information			
Relative Density	0.846	0.860	0.006
API Density	35.8	33.1	1.2
Absolute Density (kg/m^3)	844.9	858.7	6.0
Total Sulphur (wt %)	0.19	0.19	0.03
MCR (mass %)	- [b]	0.02	0.06
SW (Vol %)	-	-	-
Sediment (ppmw)	-	-	-
TAN	-	-	-
Salt in Crude (ptb)	-	-	-
Iron (mg/L)	-	-	-
Nickel (mg/L)	-	0.6	1.0
Vanadium (mg/L)	-	1.5	1.4
Molybdenum (mg/L)	-	-	-
Light Ends (Vol %)			
Methane	-	-	-
Ethane	-	-	-
Propane	0.03	0.02	0.01
isoButane	0.37	0.28	0.11
nButane	1.81	1.51	0.32
Total Butanes	2.18	1.80	0.43
Total C4 minus	2.21	1.82	0.45
isoPentane	1.73	1.10	0.19
n-Pentane	2.49	1.88	0.31
Hexanes	5.09	3.96	0.65
C7 Paraffins	1.28	1.01	0.23
C7 Naphthenes	1.29	1.09	0.17
C7 Aromatics	0.38	0.29	0.06
nHeptane	1.48	1.23	0.19
Total Heptanes	4.43	3.62	0.52
C8 Paraffins	1.63	1.56	0.21
C8 Naphthenes	1.35	1.35	0.18
C8 Aromatics	0.89	0.82	0.12
nOctane	0.93	0.91	0.13
Total Octanes	4.80	4.64	0.60
C9 Paraffins	0.93	0.97	0.13
C9 Naphthenes	0.76	0.79	0.13
C9 Aromatics	1.36	1.47	0.21
nNonane	0.78	0.75	0.10
Total Nonanes	3.83	3.98	0.50
C10 Paraffins	1.35	1.25	0.19
C10 Naphthenes	0.07	0.13	0.11
C10 Aromatics	-	0.00	-
nDecane	0.75	0.77	0.13
Total Decanes	0.17	2.17	0.32

TABLE 3.13.5-2 Constituents and Properties of Suncor Synthetic A Crude Oil			
Characteristic	**Observed**	**Past Average**	**Standard Deviations [a]**
Distillation Information (°C) % Off			
IBP	-	34.5	1.6
1%	-	37.5	3.3
5%	-	92.2	14.3
10%	-	132.9	12.4
15%	-	167.0	12.2
20%	-	196.1	12.4
25%	-	223.5	12.3
30%	-	247.7	11.5
35%	-	267.9	10.4
40%	-	285.6	9.7
45%	-	300.9	8.6
50%	-	314.6	8.0
55%	-	327.8	7.7
60%	-	341.0	7.4
65%	-	354.1	7.2
70%	-	367.3	7.1
75%	-	381.3	7.1
80%	-	396.9	7.1
85%	-	414.3	6.8
90%	-	434.3	7.2
95%	-	464.8	8.4
98%	-	502.2	13.8
99%	-	533.5	21.9
100%	-	-	-
FBP	-	572.5	31.3
Residue (%)	-	0.00	-
Yield on Crude (Vol %)			
C4 and lighter (mass %)	2.2	1.8	0.4
Naphtha (C5; 190°C)	-	16.3	2.2
Kerosene (190°C – 277°C)		20.2	1.9
Distillate (277°C – 343°C)	-	22.1	1.0
Gas Oil (343°C – 565°C)	-	23.2	10.9
Residue (565°C +)	-	-	-
BTEX (Vol %)			
Benzene	0.09	0.05	0.03
Toluene	0.30	0.23	0.05
EthylBenzene	0.15	0.15	0.03
Xylenes	0.57	0.52	0.08

[a] Past Average and Standard Deviations include 100 records.
[b] - (dash) indicates a tested value below the instrument threshold.
kg/m^3 = kilogram per square meter; wt = weight; vol = volume; mg/L = milligram per liter
Source: Crude Quality Inc. 2010.

More characteristics of these example oils are reported in copyrighted assays by Crude Quality, Inc. (website: http://www.crudemonitor.ca/current.html). Some characteristics could not be described or distilled from assay data for the example oils for this EIS, including viscosity profiles, proportion of volatile and semi-volatiles compounds, the amount or proportion of PAHs, and toxicity to aquatic organisms based on bioassays. In the fate, transport and impact assessment discussions that follow, information on these characteristics is therefore drawn from the available literature in the public record.

A comparison of typical heavy crude oils refined currently in the Houston area with the crude oils that would be transported on the proposed pipeline indicates that they are similar in composition and would therefore likely produce similar emissions during refining. A 2003 report to EPA prepared by the American Petroleum Institute (API) compared the health effects of synthetic crude oil with those of conventional crude oil and included the following statement (API 2003, page 9):

> "Synthetic crude oil, from upgraded tar sands, is compositionally similar to high quality conventional crude oil (>33º API). The conventional technologies such as delayed and fluid coking, hydrotreating, and hydrocracking, used to upgrade heavy crude oils and bitumens, are used to convert tar sands into an essentially 'bottomless' crude, consisting of blends of hydrotreated naphthas, diesel and gas oil without residual heavier oils . . . This information was supplied to EPA . . . to support the position that tar sands-derived synthetic crude oil is comparable to conventional crude oils for health effects and environmental testing, a position with which EPA concurred."

However, based on current production projections and the market demand at Gulf Coast refineries, the majority of crude oil that would likely be transported by the proposed Project would be dilbit crude oils (EnSys 2010).

Several commenters on the draft EIS expressed concerns relating to the chemical composition of the WCSB crude oil, in particular the dilbit crude oil, that would be transported through the proposed Project in relationship to other crude oils from other sources. Commenters also expressed concern about corrosion inhibiting agents that could be added to the crude oil prior to acceptance into the proposed pipeline. Corrosion inhibitors may be added to the crude oil stream with concentrations determined based on crude oil composition, supplier recommendations, and laboratory testing. Any heavy metals associated with corrosion inhibiting agents would be assessed and monitored as required by restrictions imposed through tariff specifications on pipeline transportation and other applicable regulations and requirements related to deleterious crude oil stream constituents.

Additionally, commenters have expressed concern about the potential for gas pocket formation within the pipeline due to the presence of diluents in the crude oil stream for the proposed pipeline. However, according to PHMSA, the potential for gas pocket formations exists for normal crude oil transport. There are no technical studies that indicate whether the potential for gas pocket formation would be any different for crude oils likely to be transported by the proposed Project. Gas pocket formation could occur during a slack-line condition. A slack-line condition can occur in any crude oil pipeline when line flow is insufficient to keep the entire pipe volume filled with liquid, leading to sporadic non-liquid volume pockets. Gas pocket formation is related to local topography and crude oil flow rates. Real time transient modeling addresses this concern, although leak detection sensitivity can be affected. Special Conditions 25 through 32 of the 57 Project-specific Special Conditions developed in consultation with PHMSA and incorporated into the proposed Project design, construction, and maintenance plan by Keystone specifically address the requirements of the SCADA system and its ability to detect leaks within the limitations of current technology. These conditions also address the requirement for SCADA operator training, including training to address transient flow conditions, and the need for the SCADA system to assess flow characteristics upstream and downstream of valve locations. Further, in response to a data

request from DOS concerning design approach to address slack flow conditions, Keystone provided the following:

> "Slack flow is defined as a condition where the pressure of the crude oil inside the pipeline is reduced such that the pipeline pressure is less than the vapor pressure of the crude oil itself. The Keystone XL pipeline, under design operating conditions, will not operate in slack flow. Keystone has ensured the operating regime allows for adequate pressure on the crude oil such that a slack flow condition will not arise. The pipeline's controls philosophy (inclusive of valve controls) accomplishes this by regulation of the suction and discharge pressures at the pump stations so they don't drop below the vapor pressure of the crude oil. Further, the pressure in the pipeline is continuously monitored by the Operations Control Center where pressure readings from transmitters placed no more than 20 miles apart along the pipeline are reported back through the SCADA system. Additionally, as Keystone has avoided extreme elevation changes along the route, natural causes for slack flow are eliminated."

DOS has assessed the chemical composition of heavy crude oils likely to be transported through the proposed pipeline and compared them to other heavy crude oils, in particular those currently refined in PADD III, a major destination for heavy crude oil transported by the proposed Project. DOS has also compared the chemical composition of WCSB oil sands derived crude oils with conventional (i.e., non-oil sands derived) WCSB crude oils. These assessments are presented in the following sub-sections.

Comparison of WCSB Heavy Crude Oils with Other Heavy Crude Oils Currently Refined in PADD III

Mexican Maya, Venezuelan Bachaquero, and Venezuelan Petrozuata crude oils are examples of heavy crude oils currently refined in PADD III. Maya is the "marker" heavy crude oil in the U.S. Gulf Coast with an API gravity ranging from approximately 22 to 25, with a sulfur content of approximately 3 to 3.7 percent by weight. Maya has greater than 35 percent vacuum residue by weight that is approximately 5 percent sulfur by weight and high in vanadium and nickel (combined concentration greater than 300 ppm). The two Venezuelan heavy crude oils have a sulfur content ranging from 2.4 to 2.7 percent by weight and a combined nickel and vanadium content of approximately 400 ppm. The vacuum residue for these two crude oils is approximately 59 percent by weight, and some Venezuelan crudes (such as those from the Orinoco region) have a vacuum distillation residue of 60 percent by weight with a combined vanadium and nickel content in the range of 500 to 600 ppm.

A summary of the range of properties for heavy crude oils currently refined in the PADD III area is provided in Table 3.14.3-7. For comparison purposes, the table also includes properties for two heavy sour crude oils from the Middle East (Dubai Fateh and Arabian Safaniya) and a Canadian dilbit (Cold Lake Blend, a mixture consisting of approximately 70 percent bitumen and 30 percent gas condensate) that may or may not be transported by the proposed Project based on current Project planning. As discussed in more detail below, the WCSB crude oils that would be transported by the proposed Project have characteristics that make them of similar quality to heavy crude oils currently refined in PADD III.

The typical chemical composition of the Keystone crude oil streams that would be transported by the proposed Project from the WCSB was provided in the May 1, 2009 Response to DOS Data Request #1. An update and additional details on the general composition of crude oil that would be transported by the proposed Project was provided in the July 15, 2010 Response to DOS Data Request #4.

Chemical Constituents

Chemical characteristics of a selection of crude oils are presented in Table 3.13.5-3. These selected crude oils include:

- Western Canadian Select and Suncor Synthetic crudes, representative of WCSB crude oils that would be transported by the proposed Project;
- Crude oils that are currently refined in PADD III and that would be partially or wholly replaced by crude oils that would be transported by the proposed project;
- Two reference heavy crude oils from the Middle East; and
- Another representative WCSB crude oil, the Canadian Cold Lake Blend.

It is apparent from the table that the heavy crude oils that would be transported by the proposed Project are comparable to the existing heavy crude oils refined in PADD III. The sulfur content is similar to Mexican Maya, but slightly higher than the other heavy crude oils such as Venezuelan Bachaquero. Nickel and vanadium content would be higher than the Middle Eastern crude oils, but lower than Mexican Maya and the Venezuelan crude oils. Overall, the nickel and vanadium content of the WCSB crude oils is within the expected range for crude oils with an API gravity less than 28 (API 2011). Additionally, mercury content, although not typically reported in crude oil assays, would likely be lower since Canadian crude oils, and WCSB crude oils in particular, have lower concentrations of total mercury than oils from foreign sources such as Mexico and South America (Hollebone and Yang 2007). Heavy crude oil from Mexico has not been frequently tested for mercury but estimates suggest that those levels may be two to nearly 10 times the average in WCSB crude oil and from 1.5 to 6 times higher than synthetic crudes produced from Alberta oil sands (Table 3.13.5-3). The average mercury level across all grades of Venezuelan crude oils is three times the average in Western Canadian crudes and two times the average for synthetic crudes from Alberta oil sands. Finally, the total BTEX (benzene, toluene, ethyl benzene, and xylene) content of the WCSB crude oils is higher than the Mexican Maya and Venezuelan crude oils, but considerably lower than Arabian Heavy crude oil. Also, the BTEX content of heavy oils is generally lower than lighter crude oils, many of which (e.g., West Texas Sour and Brent Blend) have twice the BTEX content of the examined heavy crude oils (Environment Canada 2011).

The quality of Maya crude imported to PADD III has recently declined. In early 2010, the Maya crude had a higher than normal salt and metals content, which led to increased downtime at Mexican refineries (Reuters, June 8, 2010 "Poor Maya crude quality hampers Mexico refineries"). Reportedly, the viscosity of Maya crude processed in Mexico has also risen sharply in recent years due to a greater proportion of extra-heavy crude oil from the Ku Maloob Zaap field being added to the domestic Maya blend. In addition to viscosity, the corrosivity of the Maya crude would also be adversely affected.

The Western Canadian Select heavy crude oil salt content (40 pounds per thousand barrels [ptb]), is higher than that of other crudes shown in Table 3.13.5-3. Data available at the Crude Monitor website indicates that the high Western Canadian Select salt content is representative of oil-sands crudes. Salt removal in the feedstock is typically required at levels above 20 ptb (Abdel-Aal et al. 2003) but 40 ptb is not considered to be at a level (e.g., 100 to 500 ptb) that would present corrosion concerns. Additionally, while the total acid number (TAN) for WCSB dilbits is in the midrange of heavy crude oils, the TAN characteristics of crude oils are not significant to the corrosion potential of steel piping at temperatures below approximately 450 degrees Fahrenheit (PHMSA 2011). The maximum operating temperature of the proposed Project pipeline would not exceed 150 degrees Fahrenheit.

TABLE 3.13.5-3
Comparison of Heavy Crude Properties

Basic Analysis	Western Canadian [a] Select Five Year Average (Heavy Sour DilBit)	Suncor Synthetic A [a] (OSA) Five Year Average (Sweet Synthetic)	Mexican Maya [b]	Venezuelan Heavy Sours (Bachaquero and Petrozuata) [c]	Cold Lake Blend [d] (Dilbit; Hardisty)	Dubai Heavy [b] (Fateh)	Arabian Heavy [e, b] (Safaniya)
Density (kg/m^3)	929.4 ± 4.8	858.6 ± 6.6	935.9 @15°C	967.9 @15°C	928.4 ± 5 @15.5°C	873.5 @15°C	0.889
Gravity (°API)	20.6 ± 0.8	33.2 ± 1.3	1.3 - 25.1	16.8 / 19.5	19.7 – 21.2	30.4 - 31.1	27 – 28
Vacuum Residue (wt%)	32 [l]	0.3 [l]	35 -- 45	59 [p]	45 -- 50	20 – 22	19
Sulphur (wt%)	3.40 ± 0.14	0.19 ± 0.03	3.0 – 3.7	2.40 / 2.69	3.66 – 3.95	2 – 2.13	2.9 – 3
Hydrogen Sulphide or Mercaptan Sulphur (wt%)	Alberta Canadian L&M Crudes [m] 0.0020% - 0.0058%	0.0100%	--	--	0.0034%	< 0.0001% [n]	
MCR (wt%)	9.46 ± 0.40	ND	--	17.3	10.48 ± 0.36	--	--
Bottom Sediment & Water (out) (%v)	0.38% ± 0.095%v	<<0.5%	0.7%-1.5% [g,h]	--	--	--	0.29% [g,h]
TAN (mgKOH/g)	0.88 ± 0.11	--	0.40	1.20	0.94 ± 0.1	0.05	0.4 [d]
Salt (ptb)	40.0 ± 13.6		--	6 [f]	--	11.9 ± 3.2	--
Mercury (mg/Kg)	1.4 ± 0.3 ; 2.2 ± 0.4 [i]	3.5; 13.5 [j]	4.2 [k, j]	--	--	--	
Nickel (mg/L)	55.9 ± 3.4	ND	45.8 ± 7 (n=3)	55 – 84	65.2 ± 3.6	14 – 19	22 – 25
Vanadium (mg/L)	134.1 ± 10.3	0.1 ± 3.8	267 ± 23 (n=4)	324 – 303	169 ± 11.2	42 – 58	70
Olefins (wt%)	ND	ND	--	--	--	--	--
Naphtha (wt%)	8.9	--	15	2 – 8	16	11.5 – 16	14.7
S:A:R:A (wt%)	11% S: --: --: 33% A	--: --: --: --	23 : 35 : 15 : 27	4 : 4 : 59 : 33	--: --: --: --	--: --: --: 2% A	--: --: --: 9.6% A 5%S: --: --: 11% A

TABLE 3.13.5-3
Comparison of Heavy Crude Properties

Basic Analysis	Western Canadian [a] Select Five Year Average (Heavy Sour DilBit)	Suncor Synthetic A [a] (OSA) Five Year Average (Sweet Synthetic)	Mexican Maya [b]	Venezuelan Heavy Sours (Bachaquero and Petrozuata) [c]	Cold Lake Blend [d] (Dilbit; Hardisty)	Dubai Heavy [b] (Fateh)	Arabian Heavy [e, b] (Safaniya)
Benzene	0.14	0.15 ± 0.02	0.05 ± 0.03	0.05	0.24 ± 0.03	6.5	0.99
Toluene	0.25	0.27 ± 0.04	0.24 ± 0.05	0.13	0.37 ± 0.05	--	3.98
Ethyl Benzene	0.05	0.06 ± 0.01	0.15 ± 0.02	0.07	0.05 ± 0.01	--	2.18

"—" No Information obtained as of the date of this report.

ND = Not Detected

S:A:R:A Percent Saturates : Aromatics : Resins : Asphaltenes in whole oil

%BS&W Out: Percent Bottom Sediment and Water after a dehydration process. For example, Maya crude has ~15% BS&W In; pre-dehydration; and 0.7-1.5% BS&W Out; post dehydration (Warren 2002)

[a] Western Canadian Select and Suncor Synthetic A crude data generally from the Canadian crudemonotor: http://www.crudemonitor.ca/crude.php?acr=WCS and http://www.crudemonitor.ca/crude.php?acr=OSH, respectively.

[b] Maya and Dubai (Fateh) data from:

http://www.etc-cte.ec.gc.ca/databases/Oilproperties/; Jacobs Consultancy and Life Cycle Associates. 2009. Life Cycle Assessment Comparison of North American and Imported Crudes. File No. AERI 1747. Prepared for Alberta Energy Research Institute. July 2009

International Crude Oil Market Handbook 2010 2010 Edition (http://www.energyintel.com/print_me.asp?document_id=655316&pID=127);

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[c] Bachaquero http://www.etc-cte.ec.gc.ca/databases/Oilproperties/;and Petrozuata.

[d] Cold Lake Blend from:

www.exxonmobil.com/apps/crude_oil/crudes/mn_cold.html; http://www.crudemonitor.ca/report.php?acr=CL
Crandall, G.R. and Purvin & Gertz. 1998. Canadian Heavy Crude / Bitumen Markets: Drivers and Challenges. No. 1998.094.
http://www.oildrop.org/Info/Centre/Lib/7thConf/19980094.pdf

[e] Arabian heavy crude data from:
Al Darouich, T. F. Béhar, C. Largeau, and H. Budzinski. 2005. Separation and Characterisation of the C15- Aromatic Fraction of Safaniya Crude Oil. *Oil & Gas Sci. Technol.Rev. IFP. 60*:681-695;

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http://www.etc-cte.ec.gc.ca/databases/Oilproperties/pdf/WEB_Arabian_Heavy.pdf

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[g] Warren, K.W. 2002. New tools for heavy oil dehydration. SPE Internl Thermal Ops and Heavy Oil Symposium & Internl Horizontal Well Technol Conf., Calgary, Alberta, CAN, 4-7 Nov. 6 pp.

[h] Sams G.W. and Warren K. 2006. New electrostatic technology for desalting crude oil. National Petrochemical & Refiners Association, Spring National Conference, March 2006.

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[i] Average for WCSB crude oils per Hollebone, B.P. and C.X. Yang, 2007, including the higher average of 2.2 mg/kg volume-weighted concentration in synthetic crude oils produced from Alberta oil sands. Mercury in Crude Oil Refined in Canada, *Environment Canada*, Ottawa, ON. 82 pp.

[j] Two estimates for mercury in Maya crude by Acosta y Asociados (2001) and EPA (1997) as cited by Acosta y Asociados (2001). Acosta y Asociados Preliminary atmospheric emissions inventory of mercury in Mexico. Project CEC-01. Prepared for Commission for Environmental Cooperation (No. 3.2.1.04). May 30, 2001. P. 18-19.

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[k] Average for all Venezuelan oil types (Wilelm et al. 2007)

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[l] Swafford, P. 2009. Understanding the quality of Canadian bitumen and synthetic crudes. Crude Oil Quality Group Meeting. February 26, 2009. 32 pp.

[m] Oil & Gas Journal Data Book, 2006. p. 240. Data for light and medium Alberta crudes; H_2S data not obtained for Western Select or Suncor Synthetic crudes but the content would likely be comparable to the listed range. http://books.google.com/books?id=YmLik9YY4uUC&pg=PA240&dq=canadian+crude+h2s&hl=en&ei=fcJoTc36HYSusAO1qJT9Cw&sa=X&oi=book_result&ct=result&resnum=2&ved=0CEUQ6AEwAQ#v=onepage&q=canadian%20crude%20h2s&f=false (last accessed 26 Feb 2011)

[n] Capline Systen Crude Oil Properties and Quality Indicators. 7 Jan 2004. http://www.caplinepipeline.com/documents/CaplineCrudeListq_4_qtr_2003.pdf (last accessed 26 Feb 2011).

[p] Ancheyta, J. and J.G. Speight. 2007. Hydroprocessing of heavy oils and residua. CRC Press. 345 pp.

Sediment and Water Content

A substantive amount of water and inorganic particulate material is entrained in heavy crude oil during extraction and production. However, in its tariff stipulations, the U.S. Federal Energy Regulatory Commission (FERC) would require that the proposed Project reject crude oil streams that exceed a combined bottom (or basic) sediment and water (BS&W) content of 0.5 percent by volume. Specifically, Article 4 (Quality) of the FERC tariff would set forth the following specifications to govern the quality of the crude oil that shippers may tender for transportation in the proposed pipeline:

> "4.1 **Permitted Petroleum**.
>
> Only that Petroleum having properties that conform to the specifications of Petroleum described in Sections 4.2, 4.3 and 4.4 following will be permitted in the Pipeline System. Shipper will not Tender to Carrier (Keystone XL), and Carrier will have no obligation to accept, transport or deliver Petroleum which does not meet said specifications.
>
> 4.2 **Specifications of Petroleum**.
>
> For the purposes of Section 4.1, the specifications of the Petroleum shall be as follows: (i) Reid Vapor Pressure shall not exceed one hundred and three kilopascals (103kPa); (ii) sediment and water shall not exceed one-half of one percent (0.5%) of volume, as determined by the centrifuge method in accordance with ASTM D4007 standards (most current version) or by any other test that is generally accepted in the petroleum industry as may be implemented from time to time; (iii) the temperature at the Receipt Point shall not exceed thirty-eight degrees Celsius (38°C); (iv) the density at the Receipt Point shall not exceed nine hundred and forty kilograms per Cubic Meter (940 kg/m3); (v) the kinematic viscosity shall not exceed three hundred and fifty (350) square millimeters per second (mm2/s) determined at the Carrier's reference line temperature as posted on Carrier's electronic bulletin board; and (vi) shall have no physical or chemical characteristics that may render such Petroleum not readily transportable by Carrier or that may materially affect the quality of other Petroleum transported by Carrier or that may otherwise cause disadvantage or harm to Carrier or the Pipeline System, or otherwise impair Carrier's ability to provide service on the Pipeline System.
>
> 4.3 **Modifications to Specifications**.
>
> Notwithstanding Sections 4.1 and 4.2, or any other provision in these Rules and Regulations to the contrary, Carrier shall have the right to make any reasonable changes to the specifications under Section 4.2 from time to time to ensure measurement accuracy and to protect Carrier, the Pipeline System or Carrier's personnel, provided that Carrier shall give Shipper reasonable notice of such changes prior to filing.
>
> 4.4 **Freedom from Objectionable Matter**.
>
> Petroleum shall not contain sand, dust, dirt, gums, impurities or other objectionable substances in quantities that may be injurious to Carrier, the Pipeline System or downstream facilities, or which may otherwise interfere with the transportation of Petroleum in the Pipeline System."

In addition, Special Condition 34 (see Appendix C of this SDEIS) addresses the sediment and water content of the crude oil that would be transported by the proposed Project and states the following:

> "Internal Corrosion: Keystone shall limit basic sediment and water (BS&W) to 0.5% by volume and report BS&W testing results to PHMSA in the annual report."

Any WCSB or other crude oils would need to meet this BS&W standard before the crude oil would enter the proposed pipeline (and hence supplied to a refinery). This BS&W requirement would minimize

damage to pipeline and refining equipment from corrosion and abrasive wear, and would also reduce the inefficiency of transporting and processing BS&W constituents.

Bitumen produced by the original naphtha solvent-based process (dilution centrifuge as practiced by Suncor and Syncrude) has approximately 0.3 to 0.5 percent solids and 1 to 2 percent water. This makes it unsuitable for pipelining and direct sale to traditional refineries. However, a paraffinic solvent process commercialized in the Shell-led Albian Sands project has provided the means to produce bitumens that are lower in asphaltenes, substantively lower in BS&W, and more easily blended with other refinery feed stocks (*Oil Sands Technology Roadmap: Unlocking the Potential Mining Based Bitumen Extraction*). This product meets the necessary 0.5 percent BS&W limit for pipeline transport. The post-dehydration level of the Western Canadian Select crude oil also meets the BS&W transport requirement as shown in Table 3.13.5-3.

Comparison of WCSB Conventional and Oil Sands Derived Crude Oils

Conventional (i.e., non-oil sands derived) medium and heavy crude oils from the WCSB have been transported to U.S. markets by pipeline and refined in U.S. refineries for many years. Overall Canadian crude oil imports to the U.S. approached 2 million bpd and much of this crude oil originated in the WCSB. It is therefore appropriate to compare key components of the composition of those crude oils with the WCSB oil sands derived crude oils that would be transported by the proposed Project. As stated previously, key concerns include BTEX content and sediment content in the various crude oils.

It is interesting to note that the BTEX content of non oil sands derived (i.e., conventional) medium to heavy WCSB crude oils is similar to the BTEX content of oil sands derived dilbit crude oils that would be transported by the proposed Project and less than the BTEX content of oil sands derived synthetic crude oils (see Table 3.13.5-4).

TABLE 3.13.5-4
API Gravity and Total BTEX Content for Both Medium to Heavy WCSB Conventional (non-oil sands derived) and WCSB Oil Sands Derived Crude Oils

Crude Name (Origin)	API Gravity	Total BTEX[a] (ppm)
Western Canadian Select (DilSynBit)	21.3	7,700 – 9,100
Suncor Synthetic A	35.8	11,100
Cold Lake Blend (DilBit)	21.6	9,800
SynCrude Synthetic (Canada)	31.7	13,100
CNRL Light Sweet Synthetic (Canada)	35	9,500
Bow River South (BRS) – Conventional	23.3	9,300
Lloyd Blend (LLB) – Conventional	20.9	9,700
Western Canadian Blend (WCB) – Conventional	20.7	5,800

[a] BTEX = benzene, toluene, ethylbenzene, xylenes.
Source: Crude Quality Inc. 2010.

A comparison of the sediment content of non oil sands derived (i.e., conventional) WCSB medium to heavy crude oils to the sediment content of oil sands derived WCSB crude oils (dilbit, synbit, dilsynbit) indicates that the sediment content of the conventional crude oils is on average higher than the sediment content of the oil sands derived crude oils typical of those that would be transported by the proposed Project (see Table 3.13.5-5).

TABLE 3.13.5-5 API Gravity and Total Sediment Content for Both Medium to Heavy WCSB Conventional (non-oil sands derived) and WCSB Oil Sands Derived Crude Oils		
Crude Name (Origin)	**API Gravity**	**Total Sediment (ppmw)[a]**
WCSB Conventional		
Midale (MSM)	30.3 ± 0.6	380 ± 185
Mixed Sour Blend (SO)	31.3 ± 2.2	335 ± 71
SHE (SHE)	35.2 ± 2.2	285 ± 191
Bow River North (BRN)	21.5 ± 1.2	360 ± 136
Bow River South (BRS)	23.3 ± 0.6	219 ± 73
Fosterton (F)	20.4 ± 0.6	224 ± 53
Lloyd Blend (LLB)	20.9 ± 0.8	364 ± 95
Lloyd Kerrobert (LLK)	20.6 ± 0.8	324 ± 84
Western Canadian Blend (WCB)	20.7 ± 0.8	288 ± 104
WCSB Dilbit, Synbit, Dilsynbit		
Access Western Blend (AWB)	21.9 ± 0.9	231 ± 211
Cold Lake (CL)	20.8 ± 0.8	176 ± 103
Peace River Heavy (PH)	20.7 ± 0.7	179 ± 101
Seal Heavy (SH)	20.6 ± 0.8	215 ± 118
Smiley-Coleville (SC)	20.0 ± 0.7	238 ± 69
Wabasca Heavy (WH)	20.3 ± 0.7	183 ± 110
Western Canadian Select (WCS)	20.6 ± 0.8	392 ± 95
Long Lake Heavy (PSH)	20.7 ± 1.1	217 ± 248
Surmont Heavy Blend (SHB)	19.6 ± 0.6	187 ± 166
Suncor Synthetic H (OSH)	19.8 ± 0.3	187 ± 133
Albian Heavy Synthetic (AHS)	19.2 ± 0.3	714 ± 274

[a] ppmw = parts per million by weight.
Source: Crude Quality Inc. 2010.

These sediment measurements do not include the specific composition of the type of sediment in the crude oil streams. Potential effects on pipeline corrosion related to sediment composition likely depend on specific sediment characteristics, including hardness and particle size distribution. There are anecdotal industry reports suggesting that the sediment in oil-sands crudes may contain from 7 to 25 percent of harder sediments, such as silicates (quartz/sand) and iron sulfide (pyrite). However, there is no readily available public information on the specific composition of sediments in conventionally produced crudes to compare with this anecdotal information. Special Condition 33 of the 57 Project-specific Special Conditions developed in consultation with PHMSA and accepted by Keystone includes a requirement that Keystone build the Project to allow internal inline inspection (pigging) throughout and that it prepares and implements a corrosion mitigation and integrity management plan for segments that for any reason do not allow the passage of the inline inspection device. Special Condition 34 requires Keystone to limit basic sediment and water to 0.5 percent by volume and to annually report testing results to PHMSA. Additional measures include requirements to conduct cleaning runs twice in the first year of operation, and at least annually thereafter, and to test the liquids collected during those cleaning runs, including basic sediment and water. Special Condition 34 also requires that Keystone develop internal corrosion

mitigation plans based on the results of those tests. This means that if the crude oil transported through the pipeline (whether produced conventionally or from the oil sands) did contain higher amounts of relatively hard sediments that might pose additional internal corrosion risk, Keystone would be required to develop a corrosion mitigation plan specifically to address that risk.

Habitat, Natural Resources, and Human Use Receptors

The impact of an oil spill would be heavily influenced by the types of receptors (i.e., habitats, natural resources, and human uses) that might be exposed to the oil. For this EIS, these receptors are generally categorized and described in the following bulleted list, in increasing order of likely environmental impacts and concern to the spectrum of potential stakeholders:[11]

- Terrestrial–agricultural land. Includes grazing, field and row crops, fallow fields, and similar land uses.
- Terrestrial–natural habitat. Includes native and second-growth forests, naturally restoring grasslands, and similar areas that are not being used directly by people for commercial purposes.
- Groundwater. Emphasis is on areas where a public drinking groundwater aquifer is close to the ground surface and/or is overlain by soils permeable to oil or by karst formations.
- Aquatic–wetland habitat. Includes all areas that meet the definition of wetlands.
- Aquatic–lake/pond habitat. Includes agricultural stock ponds, irrigation and drainage ditches, small and large lakes, reservoirs, and similar non-flowing waterbodies.
- Aquatic–stream/small river habitat. Includes smaller flowing waterbodies as well as those that are intermittent or ephemeral. These generally do not support commercial boat traffic and are not restricted with dams or major reservoirs. Some may support important recreational resources and activities or may be limited in beneficial uses.
- Aquatic–large river habitat. Includes large flowing waterbodies (e.g., Yellowstone River, White River, Niobrara River, Platte River, Missouri River, Loup River, Red River, and Canadian River) that are perennial, may support commercial traffic, and/or may be restricted by dams and major reservoirs.
- Threatened and endangered species and their critical habitat. Most are USAs and are a special case of resources that may be found in any of the habitats but are limited in population size or spatial distribution.
- Human use–residential. Areas where the proposed pipeline ROW is near rural, suburban, or urban populations. Towns and cities generally have population densities that qualify the area as an HCA. Areas of special concern include any concentrations of low-income or minority populations that could represent environmental justice issues.
- Human use–recreational. Areas, especially lakes, small and large rivers, and reservoirs and associated parks used by people for various recreational activities.
- Human use–commercial. Areas that may be closed to normal use during a spill response action and result in substantive economic impacts.

[11] The directly impacted stakeholders (e.g., ranchers, farmers, homeowners) would likely consider the impacts to their resources as very high concern regardless of the overall impact in an ecosystem context. Also, USAs and HCAs would be considered sensitive receptors due to their designation and their ecological or human use significance.

- Human use–surface water intakes. Many public water intakes are located in reservoirs, and large rivers. Human uses include drinking water, industrial cooling water, and/or agricultural water.

Season

The season in which a spill occurs could dramatically influence spill behavior, fate, impacts, and cleanup response actions. Seasonal variations in potential spill behavior are addressed in this section.

Spring-Fall

The length and timing of the spring-fall season depends on location along the proposed pipeline route and the ambient weather regime. For this EIS, this time period is generally defined as the period when the ground is mostly free of snow and access to the proposed pipeline ROW is not restricted by snow and ice. Most of the rivers and creeks are flowing; ponds, lakes, and reservoirs exhibit open water; land is mostly snow-free; and biological use of land and waterbodies is high. Currents, winds, and passive spreading forces would disperse spills that reach the waterbodies. Spills to land would directly affect the vegetation, although dispersal of the spilled material is likely to be impeded by the vegetation. Spills to wetlands may float on the water or be dispersed over a larger area than would spills to dry land or to ice and/or snow-covered land and waterbodies associated with the wetlands.

Winter

Winter is the period when waterbodies may be covered with ice and possibly snow, and the land surface may be partially to completely covered with snow. Dispersal of oil spilled to the land generally would be slowed, although not necessarily stopped, by the snow cover. Depending on the depth of snow cover as well as the temperature and volume of spilled material, the spill may reach the underlying dormant vegetation or wetlands, ponds, and lakes. Similarly, spills to flowing rivers and creeks generally would be restricted in area by the snow and ice covering the waterbody, compared to seasons with little or no snow and ice cover. Spills under the ice to creeks, rivers, and ponds/lakes might disperse slowly as the currents are generally slow to non-existent in winter. However, because of snow and ice, winter spills may be harder to detect and, when found, more difficult to contain and clean up.

Freeze-up and Breakup in Aquatic Environments

Freeze-up is the transition time in the fall when the lakes and rivers begin to freeze over in the northern regions of the pipeline route. Breakup or spring melt is the short transition period between winter and spring when thawing begins, ice thins and/or breaks up, and river flows increase substantively and quickly, often to flood stages. Major floods may cause bank erosion and ultimately pipeline failure, with the oil entering the river and likely being widely dispersed and difficult to contain or clean up.

An oil spill that results in oil reaching waterbodies during either freeze-up or breakup may be difficult to contain, remove and cleanup. The ice may not be strong enough to support people or equipment. In rivers, the oil may be transported several miles under the ice or in broken ice before it can be contained. Once the ice is strong enough to support people and equipment, it may be more difficult to detect the oil under the ice and to implement measures to affect rapid containment/cleanup at and near the spill site.

Weather and Water Levels

Weather, especially rapid warming periods and heavy rainfall, may cause rapid ice melt in rivers, snowmelt and runoff. These could result in major flood flows that breach levees along larger rivers, erode river banks, alter channels, and expose the proposed pipeline to forces that may break or rupture it.

This scenario, although a very low-likelihood event especially at HDD crossings, could occur at large or small stream or river crossings not spanned by HDD[12]. If spilled oil is released to the flooded area, especially to flowing waters, oil could be distributed to adjacent terrestrial, wetland, and aquatic habitats that normally would not be exposed. These habitats and natural resources, as well as human uses of the habitats and resources, may be exposed to the spilled material.

Concern was expressed in comments on the draft EIS relative to potential spray zones associated with operational leaks from the proposed pipeline. Winds, especially high-velocity sustained winds, could spread material released under pressure from hole(s) in the top hemisphere of an exposed portion of the pipeline to create a "spray zone." To generate a spray zone a potential leak would need to occur on the upper hemisphere of the proposed pipeline. If corrosion related leaks occurred, they would typically occur on the lower hemisphere of the pipeline and would likely be associated with entrained water. The implementation of the Project-specific Special Conditions developed in consultation with PHMSA would make such leaks highly unlikely. Potential leaks on the upper hemisphere of the proposed pipeline would likely be associated with accidental equipment impact. However, the likelihood of such events is significantly reduced by the 4-foot minimum cover requirement in most areas and the implementation of public awareness and damage prevention programs. However, if such a release were to occur, ejected material could form a cloud of mist and fine particles, and could be carried downwind. The extent of distribution would depend on wind velocity, direction of the released spray (e.g., downward into the ground, horizontal, or skyward), and characteristics of the release (e.g., pressure in the pipeline, type of oil, size of hole). Under most scenarios, the pressure in the pipeline would drop quickly, the release would be highly visible, and immediate pipeline spill control and shutdown actions would be taken[13] by the CMP and SCADA as well as the onsite personnel. If a leak would occur on the upper hemisphere of the pipeline, Keystone has estimated that the maximum spray zone for an exposed portion of the pipeline would be in the range of 75 to 400 feet (i.e., the areal extent of the release to land would be limited to a few acres or less in the immediate area of the release point and downwind of the release point).

Major flooding or adverse weather conditions (e.g., high winds, tornados, blizzards, and extreme cold) could limit Keystone's ability to detect small releases and/or hinder the spill response contractors from implementing timely and effective oil spill containment and cleanup operations. Response actions appropriate for these conditions would be addressed in the ERP and SPCC (Appendix C of the draft EIS).

3.13.5.2 Keystone Response Time and Actions

For spills ranging in magnitude from very small to substantive, response time and actions by responders would most likely prevent the oil from reaching sensitive receptors or would contain and clean up the spills before significant environmental impacts occurred. Most spills in this category are likely to occur on construction sites or at operations and maintenance facilities, and would not be released to the environment outside of these Project-related areas.

For large spills, very large spills and potentially some substantive spills, especially those that reach aquatic habitats, the response time between initiation of the spill event[14] and arrival of the response contractors would influence the magnitude of impacts to the environmental resources and human uses.

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[12] These type of events account for less than 4 percent of spills (see Table 3.13.1-3) and Keystone has a proactive, preventative plan to shut down the pipeline if severe weather or any other natural event poses a threat to the pipeline integrity.

[13] The SCADA system would shut down the pipeline within 12 minutes of detection of the release (Sections2.4.2.1 and 3.13.5.5).

[14] "Initiation of the event" means when the oil began to leak or spill to the environment, not when it is detected by either the SCADA or other means. There may be a substantive delay between initiation and detection, particularly for slow or pinhole leaks under snow or below ground.

This would be particularly true if the oil reaches flowing waters in major rivers. Once the responders are at the spill scene, the efficiency, effectiveness, and environmental sensitivity of the response actions (e.g., containment and clean up of oil, and protection of resources and human uses from further oiling) would substantively influence the type and magnitude of additional environmental impacts.

In response to a DOS data request, Keystone presented its approach to spill response under two hypothetical spill scenarios defined by DOS. The two spill scenarios presented to Keystone and its response to these scenarios provide an opportunity to review the level of preparedness and foresight that would be in place relative to potential spills from the proposed Project.

The first hypothetical spill occurs in the summer in an area with deep groundwater, relatively flat terrain, at least 2 miles from any navigable stream, no wetlands within 1 mile, and with no nearby private water wells or public water intakes. The second hypothetical spill occurs in the winter in an area of relatively shallow groundwater (25 feet bgs), sloping terrain, nearby wetlands, and a navigable stream within 1,000 feet, including private water wells within 100 feet of the release site and a public water intake 2 miles downstream.

For each of these scenarios, Keystone describes the following:

- Response procedures including pipeline shutdown, commencement of field response, spill assessment, and development of incident command post;
- The potential horizontal and vertical spread of crude oil into the environment;
- Response tactics employed for source control;
- Cleanup approaches for spills on land including containment methods and removal methods;
- Cleanup approaches for spills to groundwater including options for short- and long-term remediation;
- Cleanup approaches for spills on calm or slow moving water (lake or pond) and to flowing water (stream or river);
- Cleanup approaches for spills that occur on ice or under ice; and
- Cleanup approaches for spills in wetland areas.

DOS and PHMSA have reviewed these hypothetical spill response scenarios prepared by Keystone and would also review a final ERP to be prepared by Keystone prior to startup of the proposed pipeline (see Section 2.4.2.2 for additional information on the Keystone ERP). Based on its review of the hypothetical spill response scenarios, DOS considers Keystone's response planning appropriate and consistent with accepted industry practice.

3.13.5.3 Factors Affecting the Behavior and Fate of Spilled Oil

The primary and shorter-term processes that affect the fate of spilled oil are spreading, evaporation, dispersion, dissolution, and emulsification (Payne et al. 1987, Boehm 1987, Boehm et al. 1987, Overstreet and Galt 1995). These processes are called weathering. Weathering dominates during the first few days to weeks of a spill. A number of longer term processes also occur, including photo-degradation and biodegradation, auto-oxidation, and sedimentation. These longer-term processes are more important in the later stages of weathering and usually determine the ultimate fate of the spilled oil that is not recovered by the cleanup program.

The chemical and physical composition of oil changes with weathering. Some oils weather rapidly and undergo extensive changes in character, whereas others remain relatively unchanged over long periods. Because of evaporation, the effects of weathering are generally rapid (one to a few days) for hydrocarbons with lower molecular weights (e.g., gasoline, aviation gas, and diesel). Degradation of the higher weight fractions (e.g., crude oil, transmission and lube oil, and hydraulic fluid) is slower and occurs primarily through microbial degradation and chemical oxidation. The weathering or fate of spilled oil depends on the oil properties and on environmental conditions, both of which can change over time.

Spreading

Spreading reduces the bulk quantity of oil present in the vicinity of the spill but increases the spatial area over which adverse effects could occur. Thus, oil in flowing systems (e.g., rivers and creeks) rather than contained systems (e.g., wetlands, ponds, and lakes) would be less concentrated in any given location but could cause impacts, albeit reduced in intensity, over a larger area. Spreading and thinning of spilled oil also increases the surface area of the slick; enhancing surface-dependent fate processes such as evaporation, biodegradation and photo-degradation (see below), and dissolution. However, experience on previous oil spills suggests that the degree of spreading of an oil spill from the spill source is constrained by natural conditions in the vicinity of the release site. For example, in a crude oil release from a pipeline system on August 20, 1979 near Bemidji, Minnesota, approximately 10,700 barrels of crude oil was released onto a glacial outwash deposit consisting primarily of sand and gravel. As of 1996 the leading edge of the oil remaining in the subsurface at the water table had moved approximately 131 feet down gradient from the spill site and the leading edge of the dissolved contaminant plume had moved about 650 feet down gradient. Spreading in subsurface water is discussed further in 3.13.6.3.

Adsorption

Crude or refined oil dispersed in soil would adsorb or adhere to soil particles. Crude oil would usually bind most strongly with soil particles in organic soils and less strongly with soil particles in sandy soils. In water, heavy molecular weight hydrocarbons may bind to suspended particulates, and this process can be significant in highly turbid or eutrophic waters. Organic particles (e.g., biogenic material) in soils or suspended in water tend to be more effective at adsorbing oils than inorganic particles (e.g., clays). Sorption processes and sedimentation reduce the quantity of heavy hydrocarbons present in the water column and available to aquatic organisms. However, these processes also render hydrocarbons less susceptible to degradation. Oil in sediment tends to be highly persistent and can cause chronic impacts.

Evaporation

Evaporation is the primary mechanism for loss of low-molecular-weight constituents and light oil products. However, recent studies related to the MC-252 oil spill in the Gulf of Mexico (Deepwater Horizon incident) indicate that higher molecular weight constituents from spilled oil also volatilize over time and distance from the spill source (De Gouw 2011). As lighter components evaporate, remaining petroleum hydrocarbons become denser and more viscous. Evaporation tends to reduce oil toxicity but enhance persistence. Hydrocarbons that volatilize into the atmosphere are broken down by sunlight into smaller compounds. This process, referred to as “photo-degradation,” occurs rapidly in air; the rate of photo-degradation decreases as molecular weight increases.

Dispersion

Dispersion of oil is the spreading of oil in water and dispersion increases when water surface turbulence increases. Wind, gravity, tidal currents, or broken ice movement could cause the turbulence. Dispersion of oil into water increases the surface area of oil susceptible to dissolution and degradation processes, and

thereby limits the potential for physical impacts. However, some of the oil could become dispersed in the water column or on the bottom as it adheres to particulate matter suspended in the water column. The presence of particulates, including organic matter, silt and clay, and larger sediment particles, is likely to be greatest during spring ice breakup, flood flows, and wind storms.

Dissolution

Dissolution of oil involves soluble oil components dissolving in a water column. Dissolution in water is not the primary process controlling the fate of the oil in the environment (i.e., oil generally floats on rather than dissolves into water). Despite the characterization of crude oil that would be transported by the proposed Project as heavy crude oil, it would still be lighter than water based on its characteristic specific gravity. Some crude oil components are water-soluble and to the extent that dissolution does occur, it is one of the primary processes affecting the toxic effects of a spill, especially in confined waterbodies. Dissolution increases with decreasing hydrocarbon molecular weight, increasing water temperature, decreasing water hardness or "salinity," and increasing concentration of dissolved organic matter. Under the same environmental conditions, lighter weight petroleum hydrocarbons (e.g., BTEX) would dissolve more readily than the heavier fractions such as PAHs.

Emulsification

Emulsification is the incorporation of oil in water in a colloidal suspension. During emulsification, small drops of water become surrounded by oil. External energy from wave or strong current action is needed to naturally emulsify oil. In general, heavier oils emulsify more readily than lighter oils. The oil could remain in a slick, which could contain as much as 70 percent water by weight and could have a viscosity of a hundred to a thousand times greater than the original oil. Water-in-oil emulsions often are referred to as "mousse." Emulsifications are more common in large water bodies (e.g., large lakes, major rivers, and the ocean) where waves and/or currents mix the surface waters than in smaller water bodies where this mixing energy is usually much less.

Some commenters on the draft EIS were concerned that the bitumen component of WCSB crude oil that would be transported by the proposed Project (specifically dilbits), if released to a waterbody, would be expected to sink and accumulate on the underlying bed of the waterbody leading to difficult cleanup during spill response. This concern is apparently based on the characteristics of a bitumen-based product called Orimulsion. This product is a combination of bitumen (about 70 percent), water (about 30 percent), and surfactants (less than 1 percent) and forms an emulsion (colloidal suspension) that is materially different from the crude oils that would be transported by the proposed Project. Since the ingredients of Orimulsion do not form a solution when combined, they separate into bitumen particles, water, and surfactant when released into water. Additionally, since the specific gravity of the bitumen is either equal to or greater than the specific gravity of water, it can sink after de-emulsification. This does not occur in dilbits, such as the Western Canadian Select crude oil, because the bitumen blended with diluents forms a solution with a specific gravity less than water that would not separate when released and that would initially tend to form a lenticular mass that would float on the water column. However, given sufficient time for volatilization and biodegradation, any crude oil residuum can become more dense than water and sink.

Photo-degradation

Photo-degradation of oil increases with greater solar intensity. It can be a significant factor controlling the disappearance of a slick, especially of lighter constituents, but it would be less important during cloudy days and in winter months. Photo-degraded petroleum constituents tend to be more soluble and

more toxic than parent compounds. Extensive photo-degradation leading to increased dissolution could increase the biological impacts of a spill event.

Biodegradation

Biodegradation is the breakdown of compounds by native or introduced microorganisms. Biodegradation of oil by native microorganisms, in the immediate aftermath of a spill, would likely not be a significant process controlling the fate of oil in waterbodies previously unexposed to oil. Although oil-degrading microbial populations are ubiquitous at low densities, a sufficiently large population must become established before biodegradation can proceed at any appreciable rate. Biodegradation is typically a long-term (weeks to years) process that reduces both the toxicity and volume of spilled oil.

3.13.5.4 Summary of Environmental Factors Affecting the Fate of Spilled Oil

The environmental fate of released oil and oil products is controlled by many factors. Major factors affecting environmental fate include the spill volume, spill rate, oil temperature, terrain, receiving environment, time of year, and weather. Crude oil would weather differently than diesel or refined products in that both diesel and refined products would evaporate faster and dissolve to a greater degree into water than crude oil.

The characteristics of the receiving environment, such as the type of land cover, soil porosity, land surface topography and gradient, type of freshwater body, presence of ice and/or snow cover on water or land, and flowing water current velocity, would affect how the spill behaves. In ice-covered waters, many of the same weathering processes occur as in open water. However, ice changes the rates and relative importance of these processes (Payne et al. 1991).

The time of year when a spill occurs has a major effect on the fate of crude oil. The time of year controls climatic factors such as temperature of the air, water, or soil; depth of snow cover; presence of ice; and the depth of the active (soil frost) layer. During winter, colder air temperatures can modify the viscosity of oil so that it would spread less and potentially solidify. Temperature also affects the rate of evaporation of the volatile fraction of hydrocarbons. Frozen ground would limit the depth of penetration of any spill. Weather could also affect the ability to detect, contain, or clean up a spill.

3.13.5.5 Actions to Prevent, Detect, and Mitigate Oil Spills

The proposed Project would include processes, procedures, and systems to prevent, detect, and mitigate potential oil spills that could occur during operation of the proposed pipeline. These are summarized below. The final ERP would contain further detail on response procedures and would be completed and reviewed by PHMSA prior to granting permission to operate the proposed pipeline.

Oil Spill Prevention

Immediate control, containment, and cleanup of released oil are important factors in limiting the spatial and temporal effects of a spill. Keystone conducted a pipeline threat analysis using the pipeline industry-published list of threats under ASME B31.8S to determine the applicable threats to the proposed pipeline (see Appendix P of the draft EIS). Safeguards were then developed to protect against these potential threats, which have been identified as follows:

- Incorrect pipeline operations (e.g., overpressure of the pipeline);

- Materials and construction damage (e.g., flaws such as defective welds, dents, cracks, nicks in the coating that are a result of transport or construction, and flaws in the seam of the pipeline created during the manufacturing process);
- Corrosion (e.g., internal, external, and stress-corrosion cracking) including defects that develop over time during operation;
- Accidental damage such as external contact with the pipeline (e.g., third-party backhoes, excavators, and drills); and
- Facility damage from natural hazards (e.g., landslides, floods, and earthquakes).

Safeguards were included in the proposed Project's design and would be implemented during construction and operations. These include:

- Pipe specifications that meet or exceed applicable regulations;
- Use of the highest quality external pipe coatings (fusion bond epoxy or FBE) to prevent corrosion;
- Providing 4 feet of soil cover over the buried pipeline in most locations, which exceeds federal standards;
- Public awareness and damage prevention programs in accordance with 49 CFR 195.440 and RP 1162;
- Implementing a variety of pipeline system inspection and testing programs prior to operation, to prevent leaks. Examples of these programs include: an extensive pipeline quality assurance program for pipe manufacturing and coating; non-destructive testing of 100 percent of girth welds; hydrostatic testing in conformance with Special Conditions 8 and 22, that require the pipe to be subjected to a mill hydrostatic test pressure of 95 percent SMYS or greater for 10 seconds and the pre-in service hydrostatic test must be to a pressure producing a hoop stress of a minimum 100 percent SMYS for mainline pipe and 1.39 times MOP for pump stations for 8 continuous hours;
- An operational pipeline monitoring system (Supervisory Control and Data Acquisition [SCADA]) that remotely measures changes in pressure and volume every 5 seconds on a constant basis. These data would be immediately analyzed to determine potential product releases anywhere on the pipeline system;
- Periodic pipeline integrity inspection and cleaning programs using internal inspection tools (pigs) to detect pipeline anomalies indicating excavation damage, and loss of wall thickness from corrosion;
- Aboveground aerial and ground surveillance inspections (ground-level patrols would be undertaken in the event of a suspected leak but would not be routinely undertaken). The aerial inspections would be conducted 26 times per year (not to exceed 3 weeks apart) to detect leaks and spills as early as possible, and to identify potential third-party activities that could damage the proposed pipeline; and
- Installing MLVs along the proposed pipeline route in accordance with PHMSA regulatory requirements and PHMSA Special Condition 32 (see Appendix C of this SDEIS) to reduce or avoid spill effects to PHMSA-defined HCAs.

In addition to the regulatory requirements and industry standards to be incorporated into the design, PHMSA developed a set of Project-specific Special Conditions (see Appendix C of this SDEIS) that have

been agreed to by Keystone and would be incorporated into the proposed Project. Incorporation of those conditions would result in a Project that would have a degree of safety over any other typically constructed domestic oil pipeline system under current code and a degree of safety along the entire length of the pipeline system similar to that which is required in HCAs as defined in 49 CFR 195.450.

Oil Spill Detection

In addition to the integrity systems and measures that would be implemented as described in Section 2.4.2.1 to maintain pipeline integrity and minimize spills, the proposed Project would utilize a SCADA system that would alert the Operations Control Center (OCC) operator of an abnormal operating condition, indicating a possible spill or leak. SCADA would be installed in accordance with the requirements of 49 CFR 195.446 and the Project-specific Special Conditions (see Appendix C of this SDEIS).

SCADA facilities would be used to remotely monitor and control the pipeline system. This would include a redundant fully functional backup system available and ready for service at all times. Automatic features would be installed as integral components within the SCADA system to ensure operation within prescribed pressure limits. Additional automatic features would be installed at the local pump station level and would provide pipeline pressure protection in the event communications with the SCADA host are interrupted.

Software associated with the SCADA monitoring system and volumetric balancing would be utilized to assist in leak detection during pipeline operations. If pressure indications change, the pipeline controller would immediately evaluate the situation. If a leak is suspected, the ERP would be initiated, as described in Section 2.4.2.2. In the event of a pipeline segment shutdown due to a suspected leak, operation of the affected segment would not be resumed until the cause of the alarm (e.g., false alarm by instrumentation, or leak) is identified and repaired. In the case of a reportable leak, USDOT approval would be required to resume operation of the affected segment.

A number of complementary leak detection methods and systems would be available within the OCC and would be linked to the SCADA system. Remote monitoring would consist primarily of monitoring pressure and flow data received from pump stations and valve sites that would be fed back to the OCC by the SCADA system. Software based volume balance systems would monitor receipt and delivery volumes and would detect leaks down to approximately 5 percent of pipeline flow rate. Computational Pipeline Monitoring or model based leak detection systems would monitor small pipeline segments on a mass balance basis. These systems would detect leaks down to approximately 1.5 to 2 percent of pipeline flow rate. Computer based, non-real-time, accumulated gain/loss volume trending would assist in identifying seepage releases below the 1.5 to 2 percent by volume detection thresholds. If any of the software-based leak detection methods indicate that a predetermined loss threshold has been exceeded, an alarm would be sent through SCADA and the Controller would take corrective action. The SCADA system would continuously poll all data on the proposed pipeline at an interval of approximately 5 seconds.

In the event of a leak, the operator would shut down operating pumping units and close the isolation valves. It would take approximately 9 minutes to complete the emergency shut-down procedure (shut down operating pumping units) and an additional 3 minutes to close the isolation valves.

In addition to the SCADA and complimentary leak detection systems, direct observation methods including aerial patrols, intermittent ground patrols, and public and landowner awareness programs would be implemented to encourage and facilitate the reporting of suspected leaks and events that could suggest a threat to the integrity of the pipeline.

Oil Spill Response Procedures

Prior to the proposed Project construction, an SPCC plan consistent with EPA requirements is required to guide Keystone response in the event of unintended releases of petroleum products and hazardous materials during construction. SPCC requirements are addressed in Section 2.3 and in the CMR Plan in Appendix B of the draft EIS; a draft SPCC plan is presented in Appendix C of the draft EIS.

Prior to initiation of operation of the proposed Project, an ERP approved by PHMSA is required. The ERP is applicable to the pipeline operations and maintenance activities. The ERP would not be finalized until final definition of proposed Project elements included in all applicable permits. As noted in Section 2.4.2.2, an ERP was previously developed by Keystone for the existing Keystone Mainline and Cushing Extension project and approved by PHMSA. The ERP for the proposed Project would have the same general approach as presented in the Keystone ERP but would have many specific differences, such as the names and contact information for responders along the Project route and the differing environmental and public health vulnerabilities along the pipeline corridor. The publically available portion of the Keystone Oil Pipeline System ERP is included as Appendix C of the draft EIS (some of the ERP is considered confidential by PHMSA and the U.S. Department of Homeland Security). The Keystone ERP would be used as a template for the ERP for the proposed Project and would include Project-specific information as it becomes available. In addition, as required by 49 CFR 194.107, the response plan submitted to PHMSA would include "procedures and a list of resources for responding, to the maximum extent practicable, to a worst case discharge, and to a substantive threat of such a discharge." Once the Project route is finalized, field work would commence in collecting relevant information to be incorporated into the Project ERP which would then be submitted to PHMSA for review and approval.

Spill response procedures incorporated in the ERP would be followed in the event of a spill. Procedures that are likely to be included in the final, approved, ERP are summarized in this section. Additionally, in response to a DOS data request, Keystone provided its response procedures for two hypothetical release scenarios in areas overlying aquifers. These release scenarios are included in Appendix C of the draft EIS and further discussed in Section 3.13.6.4.

The ERP standard operating and response procedures would be utilized by the OCC operator in responding to abnormal pipeline conditions, including leak alarms. The OCC operator would have the full and complete authority to execute a pipeline shutdown. Keystone's OCC operator would follow prescribed procedures in responding to possible spills that may be reported from sources such as:

- Abnormal pipeline condition observed by the OCC operator;
- Leak detection system alarm;
- Employee reported abnormal conditions; and
- Third party reported abnormal conditions.

Upon receipt of an abnormal condition report, leak report, or leak alarm, the OCC operator would implement the following procedures:

- Follow prescribed OCC operating and response procedures for specific directions on abnormal pipeline condition or alarm response;
- Dispatch First Responders;
- Shut down the proposed pipeline within a predetermined time threshold if abnormal conditions or leak alarm cannot be positively ruled out as a leak;

- Complete internal notifications; and
- Report identified spill to federal (including National Response Center [NRC]), state and local responders as required by all applicable reporting regulations.

All Keystone employees are authorized to communicate directly with the OCC should they observe conditions that may signify a possible spill.

Response Time

In the event of a potential pipeline leak or spill, the estimated time to complete an emergency pipeline shutdown and close remotely operated isolation valves is as follows:

- Stop pumping units at all pump station locations: approximately 9 minutes;
- Close remotely operated isolation valves: approximately 3 minutes; and
- Total time: approximately 12 minutes.

Consistent with industry practice and in accordance with regulations, Keystone's response time to transfer the necessary resources to a potential leak site would follow an escalating or tier system as required by 49 CFR 194.115 (Table 3.13.5.6). Dependent on the nature of site-specific conditions and resource requirements, Keystone would meet or exceed the requirements along the entire length of the proposed pipeline system.

TABLE 3.13.5-6
Response Time Requirements of 49 CFR 194.115 along the Proposed Pipeline

Area	Tier 1 Resources	Tier 2 Resources	Tier 3 Resources
High-volume area[a]	6 hours	30 hours	54 hours
All other areas	12 hours	36 hours	60 hours

[a] "High-volume area" indicates an area where an oil pipeline with a nominal outside diameter of 20 inches or more crosses a major river or other navigable waters; because of the velocity of the river flow and vessel traffic on the river, this area would require a more rapid response in the case of a worst-case discharge or the substantive threat of such a discharge.

Spill Response Equipment

In general, Tier 1 emergency response equipment would be pre-positioned for access by Keystone including: pick-up and vacuum trucks, containment boom, skimmers, pumps, hoses, fittings, and valves, communications equipment including cell phones, two-way radios, and satellite phones, containment tanks and rubber bladders, expendable supplies, including absorbent boom and pads, assorted hand and power tools, including shovels, manure forks, sledge hammers, rakes, hand saws, wire cutters, cable cutters, bolt cutters, pliers, and chain saws, personnel protective equipment, including rubber gloves, chest and hip waders, and air monitoring equipment to detect H_2S, O_2, Lower Explosive Level, and benzene concentrations.

Additional equipment, including helicopters, fixed-wing aircraft, all-terrain vehicles, snowmobiles, backhoes, dump trucks, watercraft, bull dozers, and front-end loaders also may be accessed depending on site-specific circumstances. Other types, numbers, and locations of equipment would be determined upon concluding the detailed design of the proposed pipeline and completing Keystone's final ERP. This plan

would be completed and submitted to PHMSA for review prior to commencing operations as described above.

The primary task of the Tier 1 response team is to reduce the spread of the spill on the ground surface or water in order to protect the public and USAs, including ecological, historical, and archeological resources and drinking water locations. The Emergency Site Manager (also known as the Qualified Individual or "QI") would perform an initial assessment of the site for specific conditions, including the following:

- The nature and amount of the spilled material;
- The source, status, and release rate of the spill;
- Direction(s) of spill migration;
- Known or apparent impact of subsurface geophysical features that may be affected;
- Overhead and buried utility lines and pipelines;
- Nearby population, property, or environmental features and land or water use that may be affected;
- Location of HCAs including USAs downcurrent or down gradient from the spill site; and
- Concentration of wildlife and breeding areas.

The QI would request additional resources in terms of personnel, equipment, and materials from the Tier 2 and if necessary, the Tier 3 response teams. Once containment activities have been successfully concluded, efforts would then be directed toward the recovery and transfer of free product. Site cleanup and restoration activities would then follow, all of which would be conducted in accordance with the ERP and in conjunction with authorities having jurisdiction.

Spill Response Personnel and Training

The number of emergency responders comprising specific response teams would be determined upon completion of the proposed Project ERP. Emergency responders would meet or exceed the requirements of 49 CFR Part 194.115, and would typically be comprised of Hazardous Waste Operations and Emergency Response ("HAZWOPER") trained personnel. The response organization would follow the industry-accepted Incident Command System (ICS) and would typically consist of personnel both onsite and within an established remote or Regional Emergency Operations Center (EOC).

Locations of Spill Responders

Emergency responders would be based consistent with industry practice and in compliance with applicable regulations, including 49 CFR 194 and 49 CFR 195. Consequently, emergency responders would be based in close proximity to the following areas:

- Commercially navigable waterways and other water crossings;
- Populated and urbanized areas; and
- USAs, including ecological, historical, and archeological resources and drinking water locations.

The specific locations of other emergency responders would be determined upon conclusion of the detailed location and design of the proposed pipeline, and completion of the ERP.

Spill Training Exercises and Drills

The spill training exercise and drill program would be designed to meet the requirements of the National Preparedness for Response Exercise Program Guidelines developed by the USCG and required by the Oil Pollution Act of 1990 (OPA 90). The primary elements of the exercise program are notification exercises, tabletop exercises, equipment deployment exercises, contractor exercises, unannounced exercises by government agencies, and area-wide exercises up to and including actual field drills conducted by industry and government agencies.

Operating personnel would participate in exercises or responses on an annual basis in order to ensure that they remain trained and qualified to operate the equipment in the operating environment and to ensure that the ERP is effective. However, personnel and equipment that are assigned to multiple Response Zones would participate in only one deployment exercise per year.

Mitigation and Liability

Mitigation

Federal, state, and local agencies would participate in response activities consistent with their authorities and duties under applicable regulations and consistent with the requirements of the ERP. Required mitigation for crude oil or oil products spill impacts would be determined by these agencies. In addition, the state, tribal, and federal natural resource trustee agencies could require a NRDA under either OPA 90 or the Comprehensive Environmental Restoration Compensation and Liability Act (CERCLA), depending on the types of materials spilled, to assess the magnitude of the impacts and the type/amount of suitable restoration actions to offset the loss of natural resource services resulting from the spill.

Liability

Many commenters requested information regarding what Keystone's liability would be in the event of an accidental release of crude oil from the Project. Section 1001(32)(B) of the OPA 90 states that in the case of an onshore facility, any person owning or operating the facility is the responsible party. Additionally, under Section 1002 of OPA 90, Keystone would be liable for any discharge of oil (or threat of discharge) to the navigable waters of the United States and their adjoining shorelines. The term "navigable waters" is defined in OPA 90 as "the waters of the United States, including the territorial sea" (OPA 90). In Rice v. Harken Exploration Co. (2001) the Fifth Circuit confirmed a lower court ruling that groundwater is not within the scope of the OPA unless a direct connection to surface waters can be affirmed. Otherwise it is likely that any spill with the potential to contaminate surface waters of the United States would fall within the purview of OPA 90.

Therefore, if there is an accidental release that could affect surface water, no matter what the reason, Keystone would be liable for all costs associated with cleanup and restoration as well as other compensations, up to a maximum of $350,000,000. However this statutory liability limit does not apply where the incident was proximately caused by (1) gross negligence or willful misconduct of, or (2) the violation of an applicable federal safety construction or operating regulation by Keystone or a person acting pursuant to a contractual relationship with Keystone. Additionally, under the CWA, Keystone would be liable for up to $50,000,000 for United States removal costs for harmful quantities of oil discharged from a Keystone-owned or operated facility unless the discharge was caused solely by an act of God, an act of war, negligence by the United States, or the act or omission of a third party. The limit does not apply if the discharge resulted from Keystone's willful negligence or willful misconduct. Keystone would also be liable for damages to natural resources, to real or personal property for the loss of subsistence use of natural resources, for the net loss of taxes, royalties, rents, fees or net profit shares from

injuries to real or personal property or natural resources, for loss of profits or impairment of earning capacity by any claimant, or for net cost of providing increased or additional public services. There are no limits to these liabilities. Keystone would also be subject to the civil and criminal penalty provisions of the CWA. Keystone would also be subject to penalty provisions of the Rivers and Harbors Act and the Pipeline Safety Act.

However, if a release is caused by negligent or willful acts of others, Keystone may ultimately recover costs from those committing the acts since individuals are not automatically protected from liability associated with negligent acts or willful misconduct leading to property destruction and environmental damage. Specific liability warrants and indemnifications are included within individual easement agreements. DOS has no regulatory authority to intervene in the negotiation of those agreements. In addition, consideration of liability is beyond the scope of NEPA environmental reviews and is therefore not addressed in this EIS.

3.13.5.6 Types of Oil Spill Impacts

This section summarizes the types and magnitudes of physical, chemical and biological impacts that may occur to a variety of resources and activities due to spills that occur during either construction or operation of the proposed Project. However, due to the potentially greater magnitude of spill size from an accidental release from the pipeline during operation, this section focuses primarily on crude oil spills from the pipeline. The descriptions are necessarily somewhat general because of the large number of independent spill-related variables listed below, most of which have a wide range of values in magnitude, duration, and range of effects depending upon the exposed resource, and many of which are unpredictable in spatial and temporal distribution as well as frequency of occurrence. In addition, there is a wide range of values and variability of values for those variables, for the numerous human and natural resources encountered along the proposed pipeline route.

Physical Impacts

Physical impacts of spills of crude oil or petroleum products to natural resources and human uses typically result from physical coating of soils, sediments, plants, animals, or areas used by people. Physical impacts include, but are not limited to:

- Smothering living organisms so they cannot feed or obtain oxygen;
- Coating feathers or fur, which reduces their insulating efficiency and results in hypothermia;
- Adding weight to the organism so that it cannot move naturally or maintain balance;
- Coating sediments and soils, which reduces water and gas (e.g., oxygen and carbon dioxide) exchange and affects subterranean organisms; and
- Coating beaches, water surfaces, wetlands, and other resources used by people which may result in offensive odors, visual impacts, as well as soiled livestock, crops, clothes, recreational equipment, pets, and hands/feet.

In aquatic areas with high energy (e.g., waves, turbulent river flows, and/or high sediment deposition), the oil may become buried under or mixed into the substratum where it may remain for extended periods of time and may be slowly released to the environment to re-oil downstream habitats and resources. In some cases, the buried oil would be in an anoxic environment and would resist weathering by physical or biological processes. Upon release to the environment, this “unweathered” oil may result in additional but delayed impacts.

Potential for Explosion and Fire

Several commenters on the draft EIS expressed concern about the potential for explosion and fire associated with the operation of the proposed Project. Crude oil releases are very unlikely to result in an explosion because crude oil contains a relatively small proportion of volatile hydrocarbons and most spills do not occur in confined spaces which allow the buildup of vapors to potentially explosive levels. Almost all "petroleum or hydrocarbon pipeline explosions" occur in pipelines that are transporting highly flammable, highly volatile hydrocarbons such as natural gas, LPG, propane, LNG, gasoline, naphtha, and similar products. The released material from these product and natural gas pipelines could rapidly form a flammable vapor cloud that could explode if exposed to an ignition source in a confined area at an explosive concentration. A release of diesel, gas condensate, kerosene, or similar refined liquid hydrocarbon will ignite and burn rapidly and seem to "explode" if the vapors are exposed to a fire or similar high temperature heat source, usually a fire caused by some other accident.

The PHMSA database for significant onshore hazardous liquid incidents (PHMSA 2010) indicates that only 6 of 2,706 (0.2 percent) reported incidents were attributed to "fire/explosion as a primary cause." Those 6 incidents were related to the release of flammable hydrocarbons, such as gasoline or liquid propane, and did not involve releases of crude oil.

The pump stations for the proposed Project would be powered by electricity. As a result, there would not be natural gas or other flammable fuel at the facilities that could ignite explosively. A crude oil spill at a pump station would likely result in the emission of some hydrocarbon vapors, but the vapors would not be emitted into confined spaces and therefore an explosion would be unlikely.

Chemical and Toxicological Impacts

Toxicological impacts are a function of the chemical composition of the oil, the solubility of each class of compounds, and the sensitivity of the receptor. The primary classes of compounds found in crude oil are alkanes (hydrocarbon chains), cycloalkanes (hydrocarbons containing saturated carbon rings), and aromatics (hydrocarbons with unsaturated carbon rings). Most crude oils are more than 95 percent carbon and hydrogen, with small amounts of sulfur, nitrogen, oxygen, and traces of other elements. Crude oils contain lightweight straight-chained alkanes (e.g., hexane, heptane); cycloalkanes (e.g., cyclyohexane); aromatics (e.g., benzene, toluene); cycloalkanes; and heavy aromatic hydrocarbons (e.g., PAHs, asphaltines). Straight-chained alkanes are more easily degraded in the environment than branched alkanes. Cycloalkanes are extremely resistant to biodegradation. Aromatics (i.e., benzene, toluene, ethylbenzene, xylenes compounds) pose the most potential for toxic impacts because of their lower molecular weight making them more soluble in water than alkanes and cycloalkanes.

Toxicological impacts are the result of chemical and biochemical actions of petrogenic compounds on biological processes of individual organisms (e.g., API 1997, Muller 1987, Neff 1979, Neff and Anderson 1981, Neff 1991, Stubblefield et al 1995, Sharp 1990, Taylor and Stubblefield 1997). Impacts may include: various toxic effects to animals and birds as they try to remove the oil from their fur or feathers; direct and acute mortality; sub-acute interference with feeding or reproductive capacity; disorientation; narcosis; reduced resistance to disease; tumors; reduction or loss of various sensory perceptions; interference with metabolic, biochemical, and genetic processes; and a host of other acute or chronic effects. A description of toxicological effects of petroleum to both human and natural environment receptors is presented in Appendix P of the draft EIS.

For most construction spills, the volume and areal extent of the oil spill would be limited and generally confined to the construction ROW, construction yards, and roadways. Livestock would typically be restricted from these areas until construction activities are completed. Wild animals, especially birds and

mammals, also would tend to avoid these areas during construction. If a spill does occur and impacts a substantive amount of habitat, the response personnel would encourage and assist farmers and ranchers to move livestock if necessary.

Oil spills are not likely to have toxic effects on the general public because of the numerous restrictions that local, state and federal agencies would impose to restrict environmental exposure. Fumes from spilled oil could lead to human health effects depending on the intensity and duration of exposure. The reported range of hydrogen sulfide or mercaptan sulfur in WCSB crude oils typical of those that would be transported on the proposed Project is from 20 to 100 ppm (see Table 3.13.5-3). In the event of an oil release, the potential human exposure risk would relate to the inhalation of any hydrogen sulfide emitted into the air column in the vicinity of the oil spill. The hydrogen sulfide volatilized into the air column would be at concentrations much lower than the concentration in the crude oil. Olfactory perception of hydrogen sulfide occurs for most people at concentrations in the air of approximately 0.2 ppm. Human health effects of exposure to hydrogen sulfide, an irritant and an asphyxiant, depend on the concentration of the gas and the length of exposure. Background ambient levels of hydrogen sulfide in urban areas reportedly range from 0.11 to 0.33 parts per billion (ppb), while in undeveloped areas concentrations can be as low as 0.02 to 0.07 ppb (Skrtic 2006). A rotten egg odor characterizes hydrogen sulfide at low concentrations, and some people can detect the gas by its odor at concentrations as low as 0.5 ppb (Skrtic 2006). In an assessment of risk to first responders at crude oil spill sites, Thayer and Tell (1999) modeled atmospheric emissions of hydrogen sulfide from crude oil spills using three different crude oil hydrogen sulfide concentrations (1 ppm, 20 ppm, and 350 ppm). The results of their analysis indicate that hydrogen sulfide levels in the immediate aftermath of a crude oil spill at the two higher levels of hydrogen sulfide concentration (20 ppm and 350 ppm) could pose short-term health risks (respiratory paralysis) to first responders at the spill site. However, since initial responders do not typically arrive at spill sites immediately and model results indicate that even under worst-case conditions (no wind), modeled exposures drop to non-toxic levels in less than 4 minutes, hydrogen sulfide exposures would not be expected to create substantive health hazards. The rapid atmospheric dissipation of hydrogen sulfide levels indicated by these model results also suggests that risks to the general public would be very small to negligible in the event of an oil spill.

Oil spilled into surface or groundwater supplies that serve as human drinking water sources would be detected and monitored until the levels return to safe drinking water levels and the appropriate agencies authorize resumption of use of these water supplies. Water-related activities would be restricted in any area where there is oil present at levels that the health agencies and the Incident Commander consider unsafe for human exposure. Private landowners could choose to undertake activities that would increase exposure at their own risk.

Birds typically are the most affected wildlife if exposed to the chemical and toxicological effects of an oil spill, whether it is on land or on water (e.g., Holmes 1985, Sharp 1990, White et al 1995). In addition to the potential for external oiling of the feathers and hypothermia or drowning due to loss of flotation, birds may suffer both acute and chronic toxicological effects. Birds are likely to ingest oil as they preen their feathers in an attempt to remove the oil. The ingested oil may cause acute hepatic, gastrointestinal, and other systemic impacts resulting in mortality, reduced reproductive capacity, loss of weight, inability to feed, and similar effects. Oiled birds that are nesting or incubating eggs may coat the eggs or young with oil and injure or kill them. Dead oiled birds may be scavenged by other birds as well as mammals.

Fish and aquatic invertebrates could also experience toxic impacts of spilled oil, and the potential impacts would generally be greater in standing water habitats (e.g., wetlands, lakes and ponds) than in flowing rivers and creeks. Also, in general, the impacts would be lower in larger rivers and lakes and much lower under flood conditions since the toxic hydrocarbon concentrations would likely be relatively rapidly diluted.

The concentration of crude oil constituents in a spill would vary both temporally and spatially in surface water; however, localized toxicity could occur from virtually any size of crude oil spill. Acute toxicity values of various crude oil hydrocarbons to a broad range of freshwater species are presented in Table 3.13.5-7. Acute toxicity refers to the death or complete immobility of an organism within a short period of exposure. The LC_{50} is the concentration of a compound necessary to cause 50 percent mortality in laboratory test organisms. For aquatic biota, most acute LC_{50} for monoaromatics range between 10 and 100 ppm. LC_{50} for polyaromatic naphthalene was generally between 1 and 10 ppm, while LC_{50} values for anthracene were generally less than 1 ppm.

In aquatic environments, toxicity is a function of the concentration of a compound necessary to cause toxic effects combined with the compound's water solubility. For example, a compound may be highly toxic, but if it is not very soluble in water then its toxicity to aquatic biota is relatively low. The toxicity of crude oil is dependent on the toxicity of its constituents. As an example, Table 3.13.5-8 summarizes the toxicity of various crude oil hydrocarbons to the water flea, *Daphnia magna*. This species of water flea is used as a standard test organism to determine acute and chronic responses to toxicants. The relative toxicity of decane is much lower than for benzene or ethylbenzene because of the comparatively low solubility of decane. Most investigators have concluded that the acute toxicity of crude oil is related to the concentrations of relatively lightweight aromatic constituents, particularly benzene. Because the diluted bitumen crude oils have a significant amount of lighter hydrocarbons added, they tend to have higher benzene concentrations than many other heavy oils (such as Mexican Maya and Venezuelan Bachaquero), but lower than many light crude oils (such as Brent Blend or Alaska North Slope) (Environment Canada 2011).

While lightweight aromatics such as benzene tend to be water soluble and relatively toxic, they are also highly volatile. Thus, most or all of the lightweight hydrocarbons accidentally released into the environment evaporate, and the environmental persistence of this crude oil fraction tends to be low. High molecular weight aromatic compounds, including PAHs, are not very water-soluble and have a high affinity for organic material. Consequently, these compounds, if present, have limited bioavailability, which render them substantively less toxic than more water-soluble compounds (Neff 1979). Additionally, these compounds generally do not accumulate to any great extent because these compounds are rapidly metabolized (Lawrence and Weber 1984; West et al.1984). There are some indications, however, that prolonged exposure to elevated concentrations of these compounds may result in a higher incidence of growth abnormalities and hyperplastic diseases in aquatic organisms (Couch and Harshbarger 1985).

Significantly, some constituents in crude oil may have greater environmental persistence than lightweight compounds (e.g., benzene), but their limited bioavailability renders them substantively less toxic than other more soluble compounds. For example, aromatics with four or more rings are not acutely toxic at their limits of solubility (Muller 1987). Based on the combination of toxicity, solubility, and bioavailability, benzene was determined to dominate toxicity associated with potential crude oil spills.

Chronic toxicity values (most frequently measured as reduced reproduction, growth, or weight) of benzene to freshwater biota are summarized in Table 3.13.5-9. Chronic toxicity from other oil constituents may occur, however, if sufficient quantities of crude oil are continually released into the water to maintain elevated concentrations. However, that condition would not result from an accidental release from the proposed Project since the release would be a one-time occurrence and would not be continuous, and the release would be followed by the required response and repair activities.

TABLE 3.13.5-7
Acute Toxicity of Aromatic Hydrocarbons to Freshwater Organisms

Species	Toxicity Values (ppm)				
	Benzene	Toluene	Xylenes	Naphthalene	Anthracene
Carp (*Cyprinus carpio*)	40.4	---	780	---	---
Channel catfish (*Kctalurus*)	--[a]	240	---	---	---
Clarias catfish (*Clarias* sp.)	425	26	---	---	---
Coho salmon (*Oncorhyncus kisutch*)	100	---	---	2.6	---
Fathead minnow *(Pimephales*)	---	36	25	4.9	25
Goldfish (*Carassius auratus*)	34.4	23	24	---	---
Guppy (*Poecilia reticulate*)	56.8	41	---	---	---
Largemouth bass (*Micropterus*)	--	--	--	0.59	---
Medaka (*Oryzias* sp.)	82.3	54	---	---	---
Mosquito fish (*Gambusia affinis*)	---	1,200	---	150	---
Rainbow trout (*Oncorhyncus mykis)*	7.4	8.9	8.2	3.4	---
Zebra fish (*Therapon iarbua*)	--	25	20	--	---
Rotifer *(Brachionus calyciflorus)*	>1,000	110	250	---	---
Midge *(Chironomus attenuatus)*	--	--	--	15	--
Midge *(Chironomus tentans)*	--	--	--	2.8	--
Zooplankton *(Daphnia magna)*	30	41	---	6.3	0.43
Zooplankton *(Daphnia pulex)*	111	---	---	9.2	---
Zooplankton *(Diaptomus forbesi)*	---	450	100	68	---
Amphipod *(Gammarus lacustris)*	--	--	0.35	--	---
Amphipod *(Gammarus minus)*	--	--	--	3.9	--
Snail *(Physa gyrina)*	--	--	--	5.0	--
Insect *(Somatochloa cingulata)*	--	--	--	1.0	---
Chlorella vulgaris	---	230	---	25	---
Microcystis aeruginosa	--	--	--	0.85	---
Nitzschia palea	--	--	--	2.8	---
Scenedesmus subspicatus	---	130	---	---	---
Selenastrum capricornutum	70	25	72	7.5	---

[a] -- Indicates no value was available in the database; ppm = parts per million.

Note: Data summarize conventional acute toxicity endpoints from USEPA's ECOTOX database. When several results were available for a given species, the geometric mean of the reported LC_{50} values was calculated.

TABLE 3.13.5-8 Acute Toxicity of Crude Oil Hydrocarbons to *Daphnia magna*			
Compound	**48-hr LC_{50} (ppm) [a]**	**Optimum Solubility (ppm)**	**Relative Toxicity [b]**
Hexane	3.9	9.5	2.4
Octane	0.37	0.66	1.8
Decane	0.028	0.052	1.9
Cyclohexane	3.8	55	14.5
methyl cyclohexane	1.5	14	9.3
Benzene	9.2	1,800	195.6
Toluene	11.5	515	44.8
Ethylbenzene	2.1	152	72.4
p-xylene	8.5	185	21.8
m-xylene	9.6	162	16.9
o-xylene	3.2	175	54.7
1,2,4-trimethylbenzene	3.6	57	15.8
1,3,5-trimethylbenzene	6	97	16.2
Cumene	0.6	50	83.3
1,2,4,5-tetramethylbenzene	0.47	3.5	7.4
1-methylnaphthalene	1.4	28	20.0
2-methylnaphthalene	1.8	32	17.8
Biphenyl	3.1	21	6.8
Phenanthrene	1.2	6.6	5.5
Anthracene	3	5.9	2.0
9-methylanthracene	0.44	0.88	2.0
Pyrene	1.8	2.8	1.6

[a] The LC_{50} is the concentration of a compound necessary to cause 50 percent mortality in laboratory test organisms within a predetermined time period (e.g., 48 hours) (USEPA 2000).
[b] Relative toxicity = optimum solubility/LC_{50}
ppm = parts per million.
Source: USEPA 2000.

TABLE 3.13.5-9 Chronic Toxicity of Benzene to Freshwater Biota		
Taxa	**Test Species**	**Chronic Value (ppm)**
Fish	Fathead minnow (*Pimephales promelas*)	17.2 *
	Guppy (*Poecilia reticulata*)	63
	Coho salmon (*Oncorhynchus kitsutch*)	1.4
Amphibian	Leopard frog (*Rana pipens*)	3.7
Invertebrate	Zooplankton (*Daphnia* spp.)	>98
Algae	Green algae (*Selenastrum capricornutum*)	4.8 *

Note: Test endpoint was mortality unless denoted with an asterisk (*). The test endpoint for these studies was growth.

Biological (Ecological) Impacts

The physical and chemical impact processes described previously are manifested at the organism level. Additional biological and ecological impacts may manifest in local populations, communities, or entire ecosystems depending on the location, size, type, season, duration, and persistence of the spill, as well as

the type of habitats and biological resources exposed to spilled oil. Except for some endangered, threatened, or protected species, loss of a small fraction of a population of organisms would result in a minimal impact at a community to ecosystem level. Loss or reproductive impairment of a significant portion of a population or biological community from an oil spill could result in a significant environmental impact. The impact is likely to be greater if the species affected have long recovery times (e.g., low reproductive rates); limited geographic distribution in the affected area; are key species in the ecosystem; are key habitat formers; or are otherwise a critical component of the local biological community or ecosystem. Furthermore, if the species or community is a key recreational or commercial resource, biological impacts manifested at the population or community level may constitute a significant impact to human uses of the resource.

Assessment of Impact Magnitude

The magnitude of oil spill impact is primarily a function of size of the spill, type of oil, and sensitivity of the receptors affected (API 1992, API 1997, NRC 1985, 2003a, 2003b). The crude oil that would be transported by the proposed Project would primarily consist of diluted bitumen (dilbit) and syncrude. Information on the chemical characteristics of these crude oils is provided in Section 3.13.5.1. Variations in spill size and receptor type are key variables for estimating the magnitude of environmental impacts of oil spills from the proposed Project. Spill volume categories used in this impact assessment are presented in Section 3.13.2.1. Receptor sensitivity is subjective and is influenced by the perspectives and biases of evaluators and the actual sensitivity of the receptors to the oil. For example, a farmer whose grain field is oiled could consider impacts to a crop more significant than spill related impacts on a wetland that supports threatened and endangered species, recreational hunting, and other recreational opportunities. Conversely, a national wildlife refuge manager could evaluate relative impacts very differently. The relative sensitivities of receptors are presented in Table 3.13.5-10, based on historical spill sensitivity assessments and input from a typical range of stakeholders.

The magnitude of environmental impacts generally increases within a receptor type as spill size increases (i.e., from left to right in Table 3.13.5-10). Within a spill size, the magnitude of impact increases with increasing sensitivity of the receptors (i.e., from top to bottom in the table). Combining size and sensitivity, the magnitude of impacts generally increases from top left to bottom right in the table. In many oil spills, there are clear differences in the way that stakeholders (e.g., general public, non-governmental organizations, natural resource management agencies, regulatory agencies, enforcement agencies, private businesses, municipal agencies, and others) value spill related impacts on natural resources and habitats compared to spill related impacts on human uses. Table 3.13.5-10 reflects a ranking of these values, recognizing that the concept of "impact assessment and magnitude" is anthropogenic and not a component of ecosystem function.

For this EIS, five levels of environmental impact were considered and entered into the table to indicate the generally expected magnitude of impacts from oil spills. The magnitude of impact may vary from these general trends depending on a number of site-specific variables described previously.

TABLE 3.13.5-10
Typical Ranges of Potential Crude Oil Spill Environmental Impacts[b,c]

Type of Receptor[a]	Very Small (<210 gal [5 bbl])	Small (210 – 2,100 gal [5-49.9 bbl])	Substantive (2,100 – 21,000 gal [50-499.9 bbl])	Large (21,000 – 210,000 gal [500-5,000 bbl])	Very Large (>210,000 gal [5,000 bbl])
Terrestrial–agricultural land	Negligible	Negligible to minor	Minor to substantive	Minor to substantive	Substantive
Terrestrial–natural habitat	Negligible	Minor	Minor to substantive	Substantive	Substantive
Groundwater	Negligible	Negligible	Negligible to minor	Minor to substantive	Substantive
Aquatic–wetlands	Negligible	Minor	Minor to substantive	Substantive	Major to catastrophic
Aquatic–lakes and ponds	Negligible	Negligible to minor	Minor to substantive	Substantive	Major
Aquatic–streams and small rivers	Negligible	Negligible to minor	Substantive	Major	Major to catastrophic
Aquatic–large rivers	Negligible	Negligible	Minor	Substantive to major	Major to catastrophic
Threatened and endangered species and habitat	Negligible to minor	Minor to substantive	Substantive	Substantive to major	Major to catastrophic
Human use–commercial	Negligible	Negligible to minor	Minor	Minor to substantive	Substantive to major
Human use–residential	Negligible	Negligible to minor	Minor	Minor to substantive	Substantive to major
Human use–recreational	Negligible	Negligible to minor	Minor to substantive	Substantive to major	Major to catastrophic

[a] Receptor sensitivity subjective and based on experience from previous oil spill responses and analyses.

[b] Magnitude of impact is defined as follows:

Negligible Impact – Little to no detectable impact on most resources; may be some visible presence of oil on land, vegetation, or water. Zero to few organisms apparently killed or injured. Impacts are temporary (measured in days) and spatial distribution localized to spill site. There are no detectable effects on HCAs including USAs.

Minor Impact – Measurable presence of oil and limited impacts on local habitats and organisms. Impacts are temporary (measured in days to weeks) and local (measured in acres). Some organisms, likely birds, fish, and aquatic macroinvertebrates, may be killed or injured in the immediate area. There may be limited effects on HCAs including USAs.

Substantive Impact – Patchy to continuous presence of oil on terrestrial and aquatic habitats near the spill site. Impacts may be present for weeks to a few months and affect tens of acres or a few miles of stream/river habitat. There may be impacts to the local biological community and population-level effects on organisms and human uses of the area. There may be detectable effects on HCAs including USAs.

Major Impact – Patchy to continuous and heavy presence of oil on terrestrial and aquatic habitats near the spill site and for substantive distances down gradient from the spill site. Impacts may be present for weeks to months and potentially for a year or more. The impacted area may include many acres to sections of land or wetlands, and several miles of riverine habitat. There may be effects on the local biological community and population-level impacts on organisms and habitats, as well as disruption of human uses in local oiled areas. There may be substantive effects on HCAs including USAs.

Catastrophic Impact – Mostly continuous or nearly continuous presence of oil on all habitats near and/or for substantive distances down gradient of the spill site. Impacts may be present for months to years. The impacted area may include many acres to sections of land or wetlands, and several to numerous miles of river or other aquatic habitat. There may be both local and regional disruption of human uses. There may be both local and regional impacts to biological populations and communities. There may be significant to catastrophic effects on HCAs including USAs.

[c] Spill size categories are described in Section 3.13.2.1.

3.13.6 Resource-Specific Impacts

This section addresses potential impacts related to the resources described in Sections 3.1 through 3.12 that may result from very small spills to very large spills. Additional or corroborative information on the potential impacts of oil spills is presented in Appendix P of the draft EIS.

3.13.6.1 Geology

Potential impacts from oil spills would not involve geological features that have received state or federal protection, nor would they involve any geological features of known tribal significance along the proposed route, although concerns related to paleontological resources have been identified. Potential impacts to geologic resources due to a spill from either construction or operation of the proposed Project are addressed in the following sections.

Paleontological Resources

Most spills would be confined to a construction yard, access roadway, or pipeline ROW, or to an adjacent area. The primary exceptions would be large to very large spills from pipelines that affect areas beyond the ROW. Paleontological resources exposed to a spill could be affected. Cleanup activities could also damage paleontological resources. However, a Paleontological Mitigation Plan would be developed in South Dakota and a Memorandum of Understanding (MOU) in Montana to protect significant fossil resources that may be encountered during construction or damaged as the result of an oil spill. Locations with the potential for significant paleontological fossils occur infrequently in limited areas along the proposed route.

Mineral and Fossil Fuel Resources

For surface and near-surface resources such as sand, gravel, clay and stone, small to substantive spills may result in localized reduction in resource availability and value depending on actions involved in the incident response and subsequent remedial activities. For large and very large spills, the impacts may be proportionally greater. However, the distribution of these mineral resources and their relatively undeveloped state along the ROW indicate that the overall potential for impacts to the resources and their associated industries would be small.

The proposed route would cross deposits of sand, gravel, clay, and stone, but the acreage of deposits covered by the proposed ROW is insignificant compared to the total acreage of deposits present in each state. The proposed route would not cross any currently active aggregate mining operations. Thus, impacts from spills in the vicinity of these resources would be negligible for small or even substantive spills that are rapidly contained. Even large spills would result in minor impact because of the wide spatial distribution of these resources and their current state of development.

The proposed Project route would not cross the well pads of any active or proposed oil or gas wells, although active oil and gas wells are located near the proposed ROW along some portions of the proposed route. Spills of any size would not likely result in more than minor impacts to these oil and gas resources due to the proposed pipeline's location and the depth and containment afforded by the extraction equipment, operations, and sites.

3.13.6.2 Soils and Sediments

Soils

The impact of oil spills on soil is a function of several variables, including the type of material spilled. Once oil reaches the soil surface, the depth of penetration into the soil would depend on the porosity of the soil and the extent to which it is frozen or water saturated. The area affected would be limited to that area immediately adjacent to and covered by the spill. Porous soils (e.g., sand, gravel, and moraines) are more permeable than clays and silts. Karst areas, especially where the karst formations are close to the surface and the overlying soils are porous, may be especially vulnerable to impacts from a spill, if the oil reaches and moves through the karst. Most soils along the route have low to moderate permeability providing sufficient time to control and cleanup the oil prior to extensive movement through soils.

Spills could affect soils indirectly by affecting the vegetation, which in turn could die and expose the soil to water and wind erosion or solar heating, even if the soil itself was not directly affected by the spilled material. Spill cleanup is more likely to affect the soils than the presence of the spilled material itself, unless the cleanup is well controlled and heavy traffic and digging are minimized (especially for summer spills). Oil that adsorbs to or is retained between soil grains may weather only slowly over one to several years.

Soil productivity could be negatively impacted by oil contamination particularly in the event of large to very large spills. If long-term remediation is required, beneficial uses of the soil could be restricted for the length of the remediation period or longer.

Sediments

Sediments (defined here as submerged soils in wetlands and aquatic habitats) are typically fine grained and saturated with water. They may be covered by or integrated with a substantive amount of organic material, primarily from riparian and aquatic vegetation. The sediment may be more coarse-grained in fast-flowing streams and rivers, and in areas where glacial moraines dominate the parent soil materials. Crude or refined oils typically do not penetrate beyond the surface layer in sediments unless (1) there is a substantive amount of turbulence that mixes the oil and sediments, followed by deposition of the mixture in low energy areas; (2) the interstitial spaces are large enough (e.g., in gravel and coarse sand) to allow for penetration of the oil as it sinks; or (3) physical activities associated with spill response actions mix the surface-deposited oil-sediment mixture into deeper subsurface levels of the sediment profile. Refined products also typically would not penetrate sediments because of the water content but may penetrate or be mixed further into the sediments under the same turbulent conditions or cleanup actions as for crude oil. The oil deposited on and remaining in the top sediment layer, especially in aerobic environments may be subject to biodegradation by microbes, which would reduce or eliminate long-term impacts. Oil that is incorporated into sediments, especially in the anaerobic subsurface levels, may weather very slowly. Sediments of exposed shores can retain oil for extended periods of time, even in higher energy areas (Short et al. 2007).

3.13.6.3 Water Resources

Surface Water

Spills could affect surface freshwater quality if spilled material reaches waterbodies directly or from flowing over the land. However, the vast majority of spills would likely be confined to construction yards, areas in or adjacent to the proposed pipeline ROW, or along access roads. The volumes of most spills would likely be very small to small (see spill size categories in Section 3.13.2.1). In addition, for

some portion of the winter months each year, in the northernmost portions of the route, spill responders could remove much of the spilled material from frozen ground or ice-covered waterbodies prior to snowmelt. During the rest of the year, spills could reach and affect wetlands, ponds and lakes, as well as creeks and rivers before spill response is initiated or completed.

Released oil that reaches a water body directly or indirectly would float in a lenticular layer on the water surface. In some cases, oil could be physically mixed into upper portions of the water column or incorporated into bottom sediments in high energy aquatic environments.

An oil spill that reaches a freshwater body could cause reduced dissolved oxygen (DO) concentrations and increased toxicity to aquatic organisms, particularly from dissolved phase hydrocarbons (e.g., BTEX). Because oil slicks are less permeable to oxygen than water, spilled material that reaches wetlands, ponds, or small lakes could lower DO concentrations due to a decreased influx of atmospheric oxygen and the relatively high rate of natural sediment respiration in many shallow waterbodies. In small, shallow waterbodies with limited water movement and high organic loading (e.g., small lakes, farm reservoirs, and stock ponds), increased biodegradation resulting from the addition of oil to the water column may further reduce oxygen levels.

In winter, however, a small spill would not likely contribute substantively to an oxygen deficit in most waters because biological abundance and activity are depressed and water column respiration rates at that time would be low to negligible. Furthermore, sediment respiration has less relative effect in lakes that are too deep to freeze to the bottom. Such lakes tend to be supersaturated with DO in winter (BLM and MMS 1998). An exception to such conditions could occur if spilled material were introduced to a waterbody beneath the ice cover, in very restricted waters with depleted oxygen levels and a concentrated population of overwintering fish. During open water periods in most waterbodies, especially larger lakes, rivers, and streams, spilled materials would likely result in little detectable decrease in DO levels. The high water volume (relative to the volume of oil) or the high rate of water flow would disperse oil before it affected DO concentrations.

Long-term aquatic toxicity would be less likely to occur in larger lakes and rivers because oil would be diluted or dispersed within the sediment over large areas by currents and wind and wave action. Spills into larger rivers and creeks, especially during open water periods, might result in some toxicity within the water column itself. However, in larger rivers, because of the large and rapid dilution of the oil relative to the flow volumes, these impacts would likely be limited to the first few back eddies, calm water regions and reservoir pools down current of where the spill enters the river. In smaller flowing streams, an oil spill could create direct aquatic toxicity in the water column because of the lower relative volume and rate of water flow, and thus there would be a higher likelihood of direct contact between the biota and the dispersed oil. Some toxicity might persist in these streams for a few weeks to months, until toxic compounds trapped in the sediment were washed out or until oiled sediment was covered by cleaner sediment.

Since the majority of oil spills are small in volume, these smaller spills if reaching larger lakes, would result in minimal effects on overall water quality, assuming the lake volume is substantially larger than the volume of spilled oil. Decreases in DO levels would be negligible in most cases but may be greater in large to very large spills that cover much of the water surface for a day or more. Direct toxicity would be short-term because of the high dilution volume in these lakes and the rapid evaporation of most of the potentially toxic lighter hydrocarbons. Spreading of a spill over a lake surface may have a minor to major effect on water aesthetics and recreational use. This effect could exist for days to a few weeks until the oil was removed.

Minor temporary to short-term surface water quality degradation is possible from smaller maintenance equipment and vehicle spills or leaks. Longer term water quality degradation could be associated with large to very large spills. A larger spill could also affect potable surface water sources and irrigation water supplies. As mentioned previously, the crude oils transported by the proposed Project would tend to float on the surface water column. However, as with any crude oil, over time volatilization of the aromatic fraction and biodegradation could lead to an oil residuum that would sink.

Groundwater

During construction and operation of the proposed Project, potential minor, short- to longer-term groundwater quality degradation is possible from equipment and vehicle spills or leaks. Substantive spills of refined products, especially diesel or gasoline, and substantive to very large spills of crude oil may reach groundwater where the overlying soils are porous and the upper boundary of the water table is relatively near the surface. Areas near major wetlands and meandering streams or rivers as well as the Sand Hills topographic region of Nebraska are key examples of locations where the water table may be close to the surface. In some of these areas, it may be difficult to distinguish between groundwater and surface water. A summary of locations where shallow aquifers are present and a description of the NHPAQ system in Nebraska are provided in Section 3.3.1.

Subsurface Crude Oil Migration and Groundwater Flow

The potential for crude oil or oil products migration into subsurface groundwater is determined by several factors. These factors include the areal extent of the oil spill, the viscosity and density of the material, the characteristics of the environment into which the material is released (particularly the characteristics of the underlying soils), and the depth to first groundwater. In most cases, given that vertical migration is controlled by the infiltration rate of the oil into the underlying soil, the extent of vertical migration can be mitigated by quick emergency response measures that include rapid source control (containment and collection of the oil released) (see Appendix C of the draft EIS). An evaluation of these factors is presented below.

The crude oil that would primarily be transported by the proposed Project is classified as heavy crude oil. All heavy crude oils are more viscous than lighter crude oils. Most of the crude oil transported by the proposed Project would originate from bitumen, and would either be pre-processed into a heavy synthetic crude oil or pre-processed and blended with petroleum diluents (typically a light aromatic hydrocarbon) to produce an acceptable viscosity for pipeline transport (see Section 3.13.5). These types of crude oil would become more viscous when released into the environment as the lighter aromatic fraction volatilizes. Increasing viscosity tends to reduce vertical crude oil migration rates in soil profiles. Crude oil vertical migration would be further restricted by the cooling of the crude oil after its release (a decrease in temperature will increase the viscosity of oil), particularly in the cooler months of the year.

Heavy crude oils likely to be transported by the proposed Project are less dense than water and would form a lenticular layer that floats on surface waterbodies. If crude oil infiltrates into soil formations, it would tend to form a distended lens above and slightly below the water table when groundwater is encountered, largely based on the amount of the spill and the associated vertical hydraulic head pressure. The crude oil plume would then spread horizontally, in an ellipsoid in the down-gradient direction, until it reaches a steady state based on the crude oil head pressure, groundwater flow rate, and soil characteristics. Plume expansion can also be affected by the rate of water being pumped out of an aquifer.

Studies related to oil and oil products releases from over 600 underground storage tank leaks indicate that potential surface and groundwater impacts from these releases are typically limited to several hundred feet or less from the release site (API 1998). The median length of groundwater plumes comprised of these soluble components (BTEX) was 132 feet and approximately 75 percent of these plumes were under

200 feet (API 1998). These studies indicate that the size of the oil release is the key factor influencing the ultimate oil plume dimensions (including the dissolved phase plume). While there are differences in the rate of oil movement through different soil types, hydrogeologic factors such as hydraulic conductivity and gradient are not as significant in determining ultimate plume length (API, 1998). However, on a localized basis, it is acknowledged that water withdrawals through extensive pumping can influence the hydraulic gradient.

An example of a crude oil release from a pipeline system into an environment similar to the NHPAQ system and Sand Hills topographic region occurred on August 20, 1979 near Bemidji, Minnesota. Approximately 449,400 gallons (10,700 bbl) of crude oil were released onto a glacial outwash deposit consisting primarily of sand and gravel. The water table in the spill area ranged from near the surface to about 35 feet below ground surface. As of 1996 the leading edge of the oil remaining in the subsurface at the water table had moved approximately 131 feet down gradient from the spill site, and the leading edge of the dissolved contaminant plume had moved about 650 feet down gradient.

Estimates of the hydraulic conductivity (the rate that water moves through soil) of soils at the Bemidji site ranged from 1.59 feet per day (ft/d) to 99.23 ft/d. These hydraulic conductivity estimates were provided in an oral communication with a USGS scientist with extensive experience evaluating impacts from the Bemidji spill (Delin, pers. comm. 2011). The following specific hydraulic conductivity estimates were provided (converted from meters per second to ft/d):

- 1.59 ft/d estimated from particle-size distributions (Dillard et al. 1997);
- 19.85 ft/d based on a calibrated estimate (Essaid et al. 2003);
- 20.70 ft/d based on aquifer (slug) tests (Strobel et al. 1998); and
- 99.23 ft/d based on permeameter tests (Bilir 1992).

As described in Section 3.3, the High Plains Aquifer system (which includes the NHPAQ system), exhibits hydraulic conductivities estimated to range from 25 to 100 ft/d in 68 percent of the aquifer, with an average hydraulic conductivity estimated at 60 ft/d (Weeks et al. 1988). In general, groundwater velocity (which also takes into account the porosity and the hydraulic gradient [slope of the water table]) in the High Plains Aquifer system is 1 ft/d and flows from west to east (Luckey et al. 1986).

Estimates of the hydraulic conductivity of the Sand Hills Unit of the NHPAQ system are variable, with a high end estimate of 50 ft/d (Gutentag et al. 1984) and a lower range estimate of 13 to 40 ft/d (Lappala 1978). Hydraulic conductivity values for surficial dune sands (8 inches in depth) in the Sand Hills Unit range from 16.4 to 23.0 ft/d (Wang et al. 2006). At intermediate depths within the root zone, hydraulic conductivity values range from 26.3 to 32.8 ft/d in lowland areas and from 32.8 to 49.2 ft/d in higher elevation areas. In the lower boundary of the root zone, at approximately 6.5 feet bgs, hydraulic conductivities ranged from 42.7 to 49.2 ft/d (Wang et al. 2006). These values were based on direct in-situ measurements by a constant head permeameter.

These referenced estimates for hydraulic conductivity in the NHPAQ system and the Sand Hills Unit are within the range of values estimated for the Bemidji spill site. Although the subsurface conditions in the Sand Hills Unit, the NHPAQ system, and at the Bemidji spill site are not identical, the soils exhibit similar hydraulic conductivities and flow characteristics. Based on the similarities of soils and groundwater depth at the Bemidji spill site to those of the NHPAQ system, including the Sand Hills Unit, it can be inferred that a release from the proposed Project of similar size to the Bemidji spill in that area would remain localized and the dimensions of the liquid plume and associated dissolved plume would be similar in extent to the Bemidji plume. Other shallow groundwater resources along the proposed pipeline corridor may occur within soil profiles somewhat dissimilar from the Bemidji site (see Section 3.3). In

many areas, shallow unconfined aquifers occur within alluvium in flood plains near streams and rivers. Shallow aquifers can also occur under confined conditions. Under confined conditions, the confining layer (e.g., silt or clay) would impede or prevent vertical migration of the crude oil into the aquifer. Unconfined alluvial soils are comprised of a range of soil constituents, including gravels, sands, silts, and clays in various percentages. As a result, these alluvial soils exhibit a range of hydraulic conductivities, but it is expected that in general vertical and lateral oil migration would follow similar patterns.

Response Time, Source Control, Cleanup and Remediation

Relative to reducing potential groundwater impacts, DOS recognizes the importance of rapid response leading to source control, containment, and cleanup in the event of an oil spill in shallow aquifer areas. The ability to respond in a timely and appropriate manner to an unanticipated oil release is of critical importance. In response to a DOS data request, Keystone presented its approach to spill response under two hypothetical spill scenarios defined by DOS. The two scenarios presented to Keystone and its response to these scenarios provide an opportunity to review the level of preparedness and foresight currently in place relative to potential spills in relatively shallow groundwater areas.

The first hypothetical spill occurs in the summer in an area with deeper groundwater, relatively flat terrain, at least 2 miles from any navigable stream, no wetlands within 1 mile, and with no nearby private water wells or public water intakes. The second hypothetical spill occurs in the winter in an area of relatively shallow groundwater (25 feet bgs), sloping terrain, nearby wetlands, and a navigable stream within 1,000 feet, including private water wells within 100 feet of the release site and a public water intake 2 miles downstream.

For each of these scenarios, Keystone described the following in detail:

- Response procedures including pipeline shutdown, commencement of field response, spill assessment, and development of incident command post;
- The potential horizontal and vertical spread of crude oil into the environment;
- Response tactics employed for source control;
- Cleanup approaches for spills on land including containment methods and removal methods;
- Cleanup approaches for spills to groundwater including options for short- and long-term remediation;
- Cleanup approaches for spills on calm or slow moving water (lake or pond) and to flowing water (stream or river);
- Cleanup approaches for spills that occur on ice or under ice; and
- Cleanup approaches for spills in wetland areas.

In the first scenario, a low likelihood of groundwater contamination was determined. For the second scenario, it was determined that emergency response teams would respond prior to the time the subsurface oil plume reaches groundwater. This would allow rapid cleanup of the surface plume to reduce the downward head pressure on the oil plume. However, groundwater would likely be impacted. Impacted groundwater would be remediated by short-term mechanical approaches (excavation and vacuum methods), medium-term chemical methods (chemical oxidation), biological methods (bioremediation), and long-term natural attenuation.

In most real-world spills, a combination of methods would be used to accomplish the highest degree of remediation practicable in the shortest amount of time. However, DOS acknowledges that in areas such

as the Sand Hills region, where groundwater may be very shallow (less than 10 feet bgs), some level of groundwater impact would likely occur even with very rapid and efficient spill response. Although cleanup and remediation efforts would be more complicated and potentially of longer duration if groundwater were affected, the extent of aerial contamination would be limited primarily depending on the size of the release.

Wetlands

Impacts of crude oil spills or refined product spills on wetlands are influenced by the type of oil or oil product, the amount and proportion of water surface area covered, the type of vegetation present in the wetland, and cleanup response actions. Refined products tend to be more toxic than crude oil, while crude oil tends to cause more physical impacts (e.g., smothering). Any refined or crude oil release would tend to remain on the water surface, and would therefore affect oxygen exchange between water and air, potentially affecting the water column DO content. Toxic components of a refined product release may dissolve and disperse over the affected area. In the event of a heavy crude oil release, dense stands of emergent vegetation could act like oil booms and collect oil at the edges of the stands, particularly given the heavy crude oil viscosity. Aggressive and intrusive cleanup methods could mix oil with water and sediments (which are often anoxic below the surface layer) leading to longer lasting impacts. Passive cleanup methods (including natural attenuation) are likely to cause less impact on wetland resources. Physical disruption of wetland resources below the water line during spill response could be reduced in some cases through ignition of the oil floating on the water surface[15].

Spills of refined product (e.g., diesel or gasoline) would be more likely to occur during construction. The majority of these spills would be very small to small spills from construction pads or access roads. If the spills occur in winter, the wetland may be covered in ice and spilled product may be contained by snow or remain on top of the ice. In either case, the spilled oil would likely be recovered before it directly affected wetland habitat and associated organisms. For spills occurring during the rest of the year, most of the product would float on the water or wet soil surface, although some of the volatile fraction may dissolve or disperse in water. Although gasoline spills evaporate quickly, there may be short-term acute effects on wetland wildlife and vegetation. Diesel spills tend to be more persistent, and diesel may infiltrate sediments as well as adhere to emergent vegetation.

Crude oil spills that occur during operation of the proposed Project could affect wetlands either where the proposed pipeline would cross wetlands or waterbodies (e.g., ponds, lakes, reservoirs, streams, rivers, or adjacent riparian habitats) or where the spill site is on land but upgradient of the wetland. Due to the viscosity of heavy crude oils, spills would likely be restricted in areal extent, particularly in colder months. Snow could serve as a sorbent to further restrict the spill migration. Larger spills in open water seasons could flow into wetlands, cover the water surface, coat wetland wildlife and vegetation, and restrict oxygen exchange between air and water. Some spilled crude oil could sink through the water into underlying sediments and remain there for years, depending on the amount of biodegradation and chemical or physical weathering that takes place.

Smaller refined product or crude oil spills would generally produce minor impacts on wetlands unless the wetland is small and isolated from other waterbodies. In these cases, impacts could be substantive if the majority of the wetland is exposed to the oil. Substantive and large to very large crude oil spills could

[15] Burning of oil and oiled emergent vegetation in wetlands with an overlying water layer has been used several times in Texas and Louisiana. The vegetation above the waterline along with the floating oil is burned but the submerged vegetation including the roots is generally unharmed. Regrowth occurs rapidly. This technique reduces the chances of oil exposure to birds and other wildlife, and reduces the physical impact of cleanup crews disrupting the marsh during manual removal methods.

result in substantive impacts on wetlands due to the size of the spill and the proportion of the wetlands that would be affected. Impacts could approach a catastrophic level in areas where the wetlands are heavily used by migratory waterfowl and the spill occurs during the spring or fall migration.

3.13.6.4 Biological Resources

Vegetation

Smaller spills during construction could occur within contractor yards, along access roads, at above-ground facilities and along the proposed pipeline construction ROW, and the spilled fuel or oil would generally remain localized near the release site. These spills would typically produce minor impacts on crops, native vegetation and associated wildlife. However, substantive and large to very large spills during operation would likely result in greater impacts.

Along the Steele City Segment of the proposed pipeline, winter snow cover may occasionally be sufficient to slow and limit the surficial flow of spilled oil, thus limiting the extent of damage to vegetation and habitat. On other pipeline segments and on the Steele City Segment in other seasons, the spilled oil may flow farther on the land surface. Spill response activities could cause impacts on vegetation and habitat if activities are not implemented carefully and with regard for minimal disturbance of the surface soils and vegetation.

The majority of spills would likely be very small to small (see Section 3.13.2.1 for spill volumes within spill categories) and would typically cover less than 1 acre, but large to very large spills could be extensive, with the areal extent partially dependent on topography and the density, rigidity, and structural complexity of grass/forb/shrub vegetation on the surface of the land. Overall, most past spills on terrestrial habitats have caused minor ecological damage, and ecosystems have shown a good potential for recovery, with wetter areas recovering more quickly (Jorgenson and Martin 1997, McKendrick 2000). The length of time that a spill persists depends on several factors, including oil and soil temperature, availability of oleophilic (oil-loving) microorganisms, soil moisture, and the concentration of the product spilled. For the most part, effects of land oil spills would be localized and are not expected to impact vegetation and associated habitat outside the immediate spill area. Spills that occur within or near streams, rivers, and lakes could indirectly affect riparian vegetation and habitat along these waterbodies. Affects on vegetation from subsurface leaks that reach the root zones of surface vegetation could assist in leak detection as a result of visible patches of affected vegetation along the pipeline ROW resulting from oil interference with water and nutrient uptake by plant root systems.

A large to very large spill could spread over larger areas and coat vegetation, including row crops, wild lands, seasonal wetlands, and range lands, especially down slope from the spill site. The vegetation within the spill zone could be injured, killed or coated with oil, although population level vegetation effects are unlikely. Affected vegetation may not be suitable for grazing animals and any commercial row or field crops would not be marketable.

Birds

Very small or small spills on or near the roads, construction yards, pump stations, or MLV sites would not generally affect birds, although a few individual shorebirds, waterfowl, raptors and passerine birds could be exposed to the spilled oil. Exposed individuals could die from hypothermia or from the toxic effects of ingesting the oil during preening, or from ingestion of oiled food and water. Potential impacts would likely be limited to a few individual birds, especially waterfowl and shorebirds that use small ponds and creeks affected by very small to small spills. If a very small to small size spill occurred during migration periods, greater numbers of birds could be affected. There could also be an associated impact to a few

individual scavenging birds and mammals if they feed on oiled carcasses. Very small to small spills would not be expected to cause population-level impacts.

A substantive to very large spill in terrestrial habitats could cause mortality of birds that spend time foraging or nesting on the ground, such as shorebirds, grassland nesting songbirds (passerines), and upland game birds, where they would come into direct contact with oil and oiled prey or forage. If the spilled material entered wetlands or waters, water-dependent birds such as waders, seabirds, shorebirds, and waterfowl could be exposed. The numbers of individuals oiled would depend primarily on wind conditions and the numbers of birds within and proximate to the area affected by the spill. Impacts may be detectable at the local population level, especially for resident species with limited geographic distribution, if the spill affected important breeding habitat for migratory birds, or if the spill occurred within migration staging habitats during active migration periods. The North Valley Grasslands, crossed by the proposed pipeline in Valley County, Montana (Montana Audubon 2008), is a designated globally Important Bird Area (IBA) supporting resident and migrant grassland nesting birds. Although not designated as an IBA along the route of the proposed pipeline, the Platte River and associated wetlands in central Nebraska are used for migration staging from mid-February to early April by more than 500,000 sandhill cranes during their northward migration (Audubon 2010).

If raptors, eagles, owls, ravens, crows, magpies, vultures, and other predatory or scavenging birds are present in the spill vicinity, they could become secondarily oiled by eating oiled prey. Mortality of breeding raptors likely would represent a minor loss for local populations but would not likely affect regional populations. Mortality of migrant or winter roosting aggregations of bald eagles attracted to waterfowl aggregations at migration staging and winter open water locations, could result in more significant losses for regional bald eagle populations from exposure to oiled prey.

If a large spill moved into wetlands, adjacent riparian habitats, or open water habitats of major rivers along the ROW, waterfowl species that breed, stage, or congregate in these areas during migration could be at risk. A spill entering a major river in spring, especially at flood stage, could significantly affect waterfowl in the short term by contaminating overflow areas or open water where spring migrants of waterfowl and shorebird species concentrate before occupying nesting areas or continuing their migration.

Lethal effects would be expected to result from moderate to heavy oiling of birds. Light to moderate exposure could reduce future reproductive success because of pathological effects on liver or endocrine systems (Holmes 1985) caused by oil ingested by adults during preening or feeding that interfere with the reproductive process. Oiled individuals could lose the water repellency and insulative capacity of feathers and subsequently die from drowning or hypothermia. Stress from ingested oil can be additive to ordinary environmental stresses, such as low temperatures and metabolic costs of migration. Oiled females could transfer oil to their eggs, which at this stage could cause mortality, reduced hatching success, or possibly deformities in young. Oil could adversely affect food resources, causing indirect, sub-lethal effects that decrease survival, future reproduction, and growth of the affected individuals.

In addition to the expected mortality due to direct oiling of adult and fledged birds, potential effects include: mortality of eggs due to secondary exposure by oiled brooding adults; loss of ducklings, goslings, and other non-fledged birds due to direct exposure; and lethal or sub-lethal effects due to direct ingestion of oil or ingestion of contaminated foods (e.g., insect larvae, mollusks, other invertebrates, or fish). Taken together, the effects of a large spill may be significant for individual waterfowl and their post-spill brood. Population depression at the local or regional scale would be greater than for smaller spills. However, the effects of even a large spill would be attenuated with time as habitats are naturally or artificially remediated and populations recover to again utilize them. In general, losses from substantive to very large spills would likely result in negligible to minor impacts to regional bird population levels but may result in significant impacts to local population levels.

Mammals

Most oil spills, including large to very large spills, would result in a limited impact on most of the terrestrial mammals utilizing the area affected by the spill. The extent of impacts would depend on the type and amount of oil spilled; the location and terrain of the spill; the type of habitat affected; mammal distribution, abundance, and behavior at the time of the spill; and the effectiveness of the spill response. Typically, the proportion of habitat affected would be very small relative to the area of habitat available for most mammals.

A large to very large spill could affect terrestrial mammals directly or indirectly through impacts to their habitat, prey, or forage. For example, a large spill likely would affect vegetation, the principal food of the larger herbivorous mammals, both wild (e.g., ungulates) and domestic (e.g., cattle, sheep, and horses). Some to most of these animals probably would not ingest oiled vegetation, because they tend to be selective grazers and are particular about the plants they consume. Many predators and scavengers (e.g., bears, foxes, and raccoons) could experience toxic effects through feeding on birds, other mammals, reptiles, and fish killed or injured by the oil spill. However, these effects would not generally be life threatening or long term for the predator or scavenger (White et al. 1995). Spill response activities would typically frighten most large mammals away from the spill, thus reducing the possibility of mammal ingestion of oiled vegetation. As noted previously, vegetation could be affected by the spilled oil, thus temporarily reducing local forage availability, although it is unlikely that the overall abundance of food for large herbivorous mammals would be substantively reduced.

For large spills that are not immediately or successfully cleaned up, the potential for contamination would persist for a longer time and the likelihood of animals being exposed to the weathered oil would be greater. Over time, any remaining oil would gradually degrade. Although oiling of animals would not likely remain a threat after cleanup efforts, some toxic products could remain in soil, aquatic sediments, or in or on plant tissues, potentially up to 5 years or longer. To the extent that residual oil leads to further contact or ingestion by mammals, effects to individual mammals would continue.

Small mammals and furbearers could be affected directly by spills due to oiling or indirectly through ingestion of contaminated forage or prey items. Furbearers, especially river otters, mink, muskrat, raccoons, and beavers that are dependent on or frequently use aquatic habitats would likely be exposed to oil if spills reached aquatic habitats within their range. Oiled furbearers would be susceptible to hypothermia and oil toxicity from ingestion during grooming. Impacts to small mammals and furbearers would likely be localized around the spill area and would not cause population-level impacts.

Fish and Other Aquatic Species

Spills within aquatic habitats could affect fish, macroinvertebrates (e.g., mussels, crustaceans, insects, and worms), algae and other aquatic plants, amphibians, and reptiles; many of which are prey for mammals and birds. Aquatic habitats include wetlands, ponds, lakes, reservoirs, drainage ditches, streams and rivers.

The effects of oil spills on freshwater fish, macroinvertebrates, and other aquatic organisms have been documented and discussed in reports of assessments of many previous spills (Poulton et al. 1997, Taylor and Stubblefield 1997, Vandermulen et al. 1992, API 1992a, 1992b, and 1997). Specific effects would depend on the concentration of spilled crude oil or oil product present, the length of exposure, and the stage of development (larvae and juveniles are generally most sensitive) of affected individuals. If lethal concentrations of spilled material are encountered (or sub-lethal concentrations over a long enough period), mortality of aquatic organisms would likely occur. However, extensive mortality from exposure to oil spills is typically observed in small, enclosed waterbodies and in the laboratory environment. Most

acute-toxicity values (96-hour lethal concentration for 50 percent of test organisms [LC_{50}]) for fish are generally from 1 to 10 ppm of toxic hydrocarbons. Concentrations observed within the water column beneath surface oil slicks have usually been less than the acute values for fish, macro invertebrates, and plankton. For example, extensive sampling following the *Exxon Valdez* oil spill (approximately 11 million gallons [262,000 bbl] in size) revealed that hydrocarbon levels were well below those known to be toxic or to cause sub-lethal effects in fish and plankton (Neff 1991). The low concentration of hydrocarbons in the water column following a large oil spill appears to be the primary reason for the lack of lethal effects on fish and plankton. Should a substantive to very large crude oil spill occur during proposed Project operation, the hydrocarbon concentration in flowing rivers and creeks within the affected area would likely be relatively low based on the observations made following the *Exxon Valdez* spill.

If an oil spill of sufficient size occurred in a small water body that contained fish or other sensitive aquatic species and that exhibits restricted water exchange (e.g., ponds and small, slow-flowing creeks), lethal and sub-lethal effects could occur for the fish and food resources in that water body. Toxic concentrations of oil in a confined area would result in greater lethal impacts on larval/juvenile fish than adults. Larval/juvenile fish are generally more sensitive than adults (Hose et al. 1996, Heintz et al. 1999). Sub-lethal effects include changes in overwintering and spawning behavior, reduction in food resources, consumption of contaminated prey, and temporary displacement (Morrow 1974, Brannon et al. 1986, Purdy 1989). If a large to very large spill reached a slow-flowing, small to moderate size river in summer, the impacts due to toxic exposures could be greater than in the same river when flows are higher and water temperatures are cooler.

McKim (1977) reviewed results from 56 toxicity tests and found that, in most instances, larval and juvenile stages were more sensitive than adults or eggs. Increased mortality of larval fish would be expected because they are relatively immobile and often found at the water's surface, where contact with oil would be more likely. Adult fish would be able to avoid contact with oiled waters during a spill in the open water season, but survival would be expected to decrease if oil were to reach an isolated pool of ice-covered water.

An example of potential impacts on fish food resources is provided by Barsdate et al. (1980), who studied the limnology of an arctic pond near Barrow, Alaska, with no outlet, after an experimental oil spill. The study concluded that half of the experimental spill was biodegraded or naturally attenuated during the first year. The remaining oil was trapped along the edge of the pond; most of it sank to the bottom by the end of summer. Researchers found no change in pH, alkalinity, or nutrient concentrations. Photosynthesis was briefly reduced and then returned to normal levels after several months. *Carex aquatilis*, a vascular plant, was affected after the first year due to emerging leaves encountering oil. Certain aquatic insects and invertebrates that lived in these plant beds were reduced in numbers, presumably from entrapment in the oil on plant stems. Some of the insects were still absent six years after the spill. There were no fish in this pond; therefore, the impact of the loss of a prey base to the fish could not be measured. Reducing food resources in a closed lake or pond, as described above, would decrease fitness and potentially reduce reproduction until prey species recovered.

Another potential impact could occur if oil that spilled before or during the spring floods from spring snowmelt or extremely high rainfall dispersed into some of the adjacent wetlands or lakes with continuous or ephemeral connection to rivers and large creeks. This oil could be left stranded when the water recedes and the oil could cause limited toxic or physical smothering effects to riparian, terrestrial and aquatic plants and animals in the flooded area. Lethal effects to fish in streams and some lakes would be unlikely during high-water events such as floods, because toxic concentrations of hydrocarbons would be unlikely. However, toxic levels could be reached in lakes that are normally not connected to the

river/creek system except during the high-water periods. If hydrocarbon concentrations in the water column reach toxic levels, these fish could suffer mortality or injury.

Although lethal effects of oil on fish have been established in laboratory studies (Rice et al. 1979, Moles et al. 1979), large kills following oil spills are not well documented, likely because toxic hydrocarbon concentrations in the water column seldom occur. In instances where oil does reach the water, sub-lethal effects are more likely to occur, including changes in growth, feeding, fecundity, survival rates, and temporary displacement. Other possibilities include interference with movements to feeding, overwintering, or spawning areas; localized reduction in food resources; and consumption of contaminated prey.

Most oil spills from the proposed Project would not be expected to measurably affect fish populations in the vicinity of the proposed route. Oil spills occurring in a small body of water containing fish with restricted water exchange would be expected to kill a small number of individual fish but would not be expected to measurably affect fish populations. The same assessment would generally apply to many macroinvertebrates, amphibians, and reptiles because they are motile and generally have a wide geographic distribution. However, sessile freshwater mussels with limited geographic distribution could be affected at a population level in large to very large spills that affect a substantive segment of a stream or river.

Although very unlikely, a large to very large spill under or adjacent to a river could affect water quality, aquatic resources, and other water-associated resources, as well as subsistence and recreational fisheries in downstream areas. In the winter season, an undetected spill, especially under ice, depending on the length of time until spill detection and the volume of released oil, could affect aquatic resources downstream of the spill source. Mortality could result for fish and macroinvertebrates in deeper pools within the spill migration zone. Early-arriving birds could be exposed in any open water pools and cracks in the river ice. Depending on the season of occurrence, however, containment and cleanup of a large or very large oil spill could be difficult.

Sensitive, Threatened and Endangered Species

Most of the potential impacts to the habitats used by threatened, endangered, and protected species are included in the previous discussions of impacts on biological resources. The important additional consideration for these species is that, by definition, they have limited distribution and/or population sizes. Although exposure to oil may adversely affect only a few individuals or a small, localized population of individuals, such a loss could represent a significant portion of the population and its gene pool. Consequently, even a very small or small spill could substantively affect a threatened or endangered species. The likelihood of impacts on threatened, endangered, and protected species would be low because the majority of spills would likely occur at construction yards, on roads, at pump stations, or at MLV sites that have been sited to avoid or minimize any impacts on these habitats and species.

Spilled oil is more likely to affect species that heavily use or completely depend on aquatic and wetland habitats than those in terrestrial habitats. The oil could be transported into flowing streams and rivers, especially with substantive to very large spills, and thus affect a substantive portion of some populations of aquatic species (i.e., freshwater mussels, fish, herptiles, and water birds).

Based on the results of formal consultation between DOS and USFWS, any oil spill in designated habitat for the American Burying Beetle would require initiation of additional consultation to determine appropriate response actions and follow-up. In the event of a spill sufficiently large or coincident with occupied habitat or individuals of any sensitive, threatened or endangered species, Keystone would implement provisions of the ERP to protect potentially affected habitats and species from oiling and

would conduct response actions as required by local, state, and federal agencies to return impacted areas to an agreed-upon condition.

3.13.6.5 Land Use, Recreation and Special Interest Areas, and Visual Resources

Agricultural land and rangeland is the predominant land use along the proposed pipeline corridor, comprising about 78 percent of land crossed by the proposed Project. A large to very large spill could affect agricultural activities, including irrigation water supplies.

Most very small to small spills would be confined to construction yards, roads, pump stations, MLVs, or the immediate vicinity of the proposed pipeline ROW. Substantive to very large spills would likely extend beyond the proposed ROW, although the overall extent of terrestrial releases would likely be limited unless the spilled material reaches flowing rivers or streams. Impacts from spills on recreational uses and wilderness-type values of scenic quality, solitude, naturalness, or primitive/unconfined recreation would vary depending on the overall extent of spill migration. Since the majority of releases would likely be small to very small and confined within the proposed Project ROW, their effects on these uses would be negligible to minor.

For some substantive to very large spills, particularly those that reach a stream or river, land use impacts could be substantive. Spilled oil could be visible and result in impacts to agricultural uses and recreational uses for weeks or years depending on the extent and duration of the spill. Agricultural production and crop yields within the spill zone could be reduced until remediation of affected soils and groundwater is accomplished. Rangeland forage in the spill zone could be negatively affected although livestock could likely find sufficient forage in unaffected areas. Fishing, boating, kayaking, tubing, camping, scenic values, and other recreational pursuits could be affected if spilled crude oil reaches lakes and rivers used by recreationists.

3.13.6.6 Cultural Resources

Most known cultural resources which have been previously identified would be avoided by the proposed Project alignment. Any cultural resources that are eligible for listing on the National Register of Historic Places impacted by a crude oil or oil products release would be mitigated through documentation and/or data recovery excavations consistent with the requirements of the Programmatic Agreement (PA). An Unanticipated Discoveries Plan is included within the PA. Proposed Project facilities, including the proposed pipeline, were located to minimize proximity to and potential adverse effects on identified cultural and historical resources.

Large to very large spills could impact cultural resources already identified within the Area of Potential Effect (APE) or cultural resources that are outside of the APE and are currently unidentified. Measures to avoid potential harm to historic properties would be undertaken as part of the spill response efforts. If necessary, identification and mitigation of potentially eligible cultural resources would occur during response efforts consistent with the requirements of the PA.

The proposed pipeline corridor crosses National Historic Trails administered by the NPS. If these areas were impacted by an oil or oil products spill, special care would be required during spill response actions to limit damage to the historic values of the trail systems.

3.13.6.7 Socioeconomics

Oil spills, especially large or very large spills, could affect components of the socioeconomic environment, including:

- Populated areas, especially residential areas, and other HCAs;
- Agricultural activities including farming, ranching, and livestock grazing on wild land;
- Water intakes and water supplies (e.g., drinking water and agricultural irrigation water);
- Other commercial activities; and
- Single-family home sales and property value.

Economic affects related to potential impacts to drinking water supplies could occur in the event of a large to very large oil spill. However, the proposed Project was sited to avoid water supply intakes and nearby potable groundwater well heads. Nonetheless, as discussed in Section 3.3, numerous water wells exist within a mile on either side of the proposed pipeline centerline along its route. Since all of these water wells are over 100 feet from the proposed Project centerline, the impact to these users would likely be minor for small to very small spills and could be substantive if a large to very large spill affects nearby water wells or intakes for a substantive period of time. In the event of oil spill impacts to water supplies for residential, agricultural, commercial, or public uses, Keystone would provide alternate sources of water for essential uses such as drinking water, irrigation, industrial cooling water, and water for fire fighting and similar public safety services. Economic affects related to short-term disruption in local agricultural production could result from a spill that enters agricultural lands or wild lands used by grazing livestock. The extent and duration (e.g., short term or long term) of the economic impacts would depend on the number of productive acres affected, the response time, the remedial method selected and implemented by the response team, and the length of time required to return land services to conditions similar to those prior to the spill.

Some commenters expressed concern about spilled oil reaching surface water supply intakes and affecting fire fighting capability. As stated previously, the proposed pipeline was sited to avoid water supply intakes. Additionally, most surface water supply intakes draw water well below the water surface and would therefore draw water from below the lenticular floating spill mass in the unlikely event it moved over a water intake.

If a spill affected recreational lands and/or waterways, businesses relying on hunting, fishing, sightseeing, and other recreational activities could experience a short-term negative economic impact. During response and restoration actions, access to oil-impacted areas would generally be limited or prohibited to anyone except the cleanup and monitoring crews, thus limiting recreational access. Adverse publicity about the impacts of large to very large spills could reduce use by recreationists from the local and regional areas, or even from other areas in the U.S. for an extended period of time. For small to very small spills, there would likely be negligible economic impacts to businesses relying on recreational uses. In some cases, response to oil spills could generate positive local economic activity for the limited duration of the spill response activities as a result of the need for lodging, meals, equipment, and other facilities, materials, and logistic support for the cleanup crews and the incident command team.

Economic impacts to land and residence values in areas affected by oil spills could occur. Simons et al. (2001) conducted a study of 2,300 single-family home sales before and after an oil pipeline rupture that spilled 120,000 gallons of mostly number 2 fuel oil into 10 miles of the Patuxent River in Prince George County, Maryland, in the spring of 2000. The study determined that a statistically significant reduction in sales prices of over 10 percent occurred for properties located off of the river (i.e., “interior” properties)

for the first sales season after the spill (i.e., about 6 months), and further determined that there was also a reduction in sales volumes during that period.

Hansen et al. (2006) evaluated the impacts to properties in Bellingham, Washington as a result of a June 1999 rupture of a 19-inch-diameter gasoline pipeline that spilled 229,000 gallons of gasoline into Whatcom Creek and led to an explosion and fire. Due to associated fatalities and injuries, this incident received significant national media coverage and led to a temporary halt to pipeline development and the passage of the Pipeline Safety Improvement Act of 2002. The Hansen study evaluated single-family home sales within 1 mile of the affected Olympic Pipeline, and also the Trans Mountain crude oil pipeline located less than 1,500 feet away, for 5.5 years prior to and 5 years after the incident. An analysis of 3,765 sales showed the following statistically significant reductions in the mean sale price (slightly more than $209,000) depending on distance from the pipeline:

- A reduction of $9,613 for property located 50 feet from the pipeline;
- A reduction of $4,863 for property located 100 feet from the pipeline;
- A reduction of $2,446 for property located 200 feet from the pipeline; and
- A reduction of $491 for property located 1,000 feet from the pipeline.

Over time after the spill and explosion, changes in mean sale prices within 100 feet of the pipeline varied as follows:

- A reduction of $5,813 after 6 months;
- A reduction of $4,784 after 12 months;
- A reduction of $4,267 after 24 months; and
- A reduction of $4,008 in price 48 months.

Thus, the impacts of the pipeline incident decreased somewhat over time. These data suggest that the economic consequences of an oil spill could include a temporary reduction in housing prices that would likely decrease over time.

Environmental Justice Considerations

Information on minority and low-income populations within the proposed Project environmental justice analysis area, including locations along the proposed Project corridor that are designated as HPSA and/or MUA/P areas are presented in Section 3.10. Depending on the location and volume of an accidental crude oil release from the proposed Project, it is possible that minority or low-income populations could be affected by the release. Minority and low-income populations could be more vulnerable to health impacts associated with the crude oil release, particularly if access to health care is less available in the release area. Exposure pathways could include direct contact with the crude oil, inhalation of airborne emissions from the crude oil, or consumption of food or water contaminated by either the crude oil or components of the crude oil. However, as discussed previously in Section 3.13.5.5, Keystone would be liable for all costs associated with cleanup and restoration as well as other compensations, up to a maximum of $350,000,000 for any release that could affect surface water, no matter what the reason. Therefore potential impacts to minority or low-income populations would be mitigated by the operator's liability for the release. Additionally, Keystone has committed to provide an alternative water supply if an accidental release from the proposed Project contaminates groundwater or surface water used as a source of potable water or for irrigation or industrial purposes, which includes water uses by minority and low-income populations. Given the potential vulnerability of these populations to health impacts, it is

essential that spill response planning considers appropriate communications directed to these populations in the unlikely event of an accidental crude oil release. As a measure to avoid or minimize impacts to minority or low-income populations, response planning should consider HPSA and/or MUA/P areas when assessing potential response times for any exposed populations. As an added mitigation measure, emergency communications could be provided in languages appropriate for identified populations at risk.

3.13.6.8 Air Quality

Impacts on air quality from an oil spill would be localized and transient, even for very large spills. Evaporation of the lighter hydrocarbon fractions typically occurs within one to a few days, and the vapors are usually dissipated below risk levels within a short distance of the source. Additional evaporation of the heavier compounds would take place over a longer period of time and could be an important source of organic aerosol pollution (De Gouw 2011). The oil spill response personnel would monitor air for hydrocarbon vapors. Public access to areas exceeding specified risk levels would be restricted and authorized personnel within the restricted areas would be equipped with appropriate personal protective equipment. Nearby farmers and ranchers would be informed of potential hazards to livestock and other farm animals, and assistance would be provided in moving livestock if necessary.

Based on models by Hanna and Drivas (1993), the majority of volatile organic compounds (VOCs) from crude oil spills would likely evaporate almost completely within a few hours after the spill occurred, especially during late spring/early fall when air and soil surface temperatures are higher. Emissions of VOCs, such as BTEX, would peak within the first several hours after the spill and likely drop by two orders of magnitude after approximately 12 hours. The heavier compounds would take longer to evaporate, particularly at the colder temperatures typical of the winter season, and might not peak until more than 24 hours after the spill. In the event of an oil spill on land, the air quality effects would be less severe than those for a spill on water because some of the oil could be absorbed by vegetation or into the ground. However, some effects might last longer on land before the VOC compounds are completely dissipated.

During construction, diesel fuel oil, kerosene and similar hydrocarbons could be spilled during refueling, from a broken diesel refueling line, or from accidents involving vehicles or equipment. A diesel spill would evaporate faster than a crude oil spill. Ambient hydrocarbon concentrations would be higher than for a crude oil spill but would persist for a shorter time.

Gasoline and solvents would typically evaporate and disperse very rapidly. Almost all the released volume would evaporate, except for small amounts that may seep into the upper soil and vegetation layers from which it would be released over 1 day to several days. Gasoline vapors are generally not toxic at the concentrations experienced in spills but they may lead to flammable or explosive vapor concentrations. Public and response personnel access to fire and explosion hazards would be restricted.

In general, impacts on air quality related to oil spills would be localized and short term. The associated VOC air emissions would result in little impact to the biological or physical resources in the vicinity of the spill.

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3.14 CUMULATIVE IMPACTS

The analysis of cumulative impacts was expanded to identify additional reasonably foreseeable projects, expand the discussion of GHG emissions, including information from a report prepared by ICF International at the request of DOS, and to provide additional information on environmental impacts associated with the production of WCSB crude oil. Other portions of the cumulative impacts analysis remain essentially as presented in the draft EIS and have not been repeated in the SDEIS as noted below.

3.14.1 Methods

There have been no substantive changes to this section and therefore it is not included in the SDEIS. The draft EIS subsection can be downloaded at www.keystonepipeline-xl.state.gov.

3.14.2 Past, Present, and Reasonably Foreseeable Projects

Several reasonable foreseeable projects were included in the revised assessment of cumulative impacts. Those projects are in included in Table 3.14.2-1

TABLE 3.14.2-1
Representative Projects Considered in the Cumulative Impacts Assessment[a]

Project Name (Status)	Description	States Crossed	Relationship to Proposed Project
Crude Oil Pipelines and Storage Facilities			
Express-Platte Pipeline System (existing)	Approximately 1,700 miles of crude oil pipelines that are 20 and 24 inches in diameter.	Montana, Wyoming, Nebraska, Missouri, and Illinois	The Express-Platte system would be within the proposed Project's cumulative impact corridor (PCIC)[b] near Steele City, Nebraska.
Keystone Mainline Oil Pipeline (existing)	Approximately 1,379-mile-long crude oil pipeline has a design capacity between 435,000 bpd to 591,000 barrels per day (bpd).	North Dakota, South Dakota, Nebraska, Kansas, Missouri, and Illinois.	Portions of the Keystone pipeline would be in the PCIC near Steele City, Nebraska.
Keystone Cushing Extension (existing)	298-mile-long, 36-inch-diameter crude oil pipeline.	Nebraska, Kansas, and Oklahoma.	Portions of the northern and southern ends of the Cushing Extension would be within the PCIC (near Steele City, Nebraska and near Cushing, Oklahoma).

TABLE 3.14.2-1 Representative Projects Considered in the Cumulative Impacts Assessment[a]			
Project Name (Status)	**Description**	**States Crossed**	**Relationship to Proposed Project**
BakkenLink Pipeline (planned)	Approximately 305-mile-long,12-inch-diameter oil gathering system to move Bakken crude from North Dakota to the Keystone XL system near Baker, Montana	North Dakota and Montana	The BakkenLink Pipeline would be within the PCIC near Baker Montana.
Bakken Marketlink Project (planned)	Three crude oil storage tanks and associated facilities near Baker adjacent to the proposed Pump Station 14 and two crude oil storage tanks and associated facilities at the proposed Cushing tank farm in Cushing, Oklahoma pipeline to store and inject Bakken oil production from producers in North Dakota and Montana into the proposed Project pipeline.	Montana and Oklahoma	The Bakken Marketlink Project would be within the PCIC near Baker, Montana and near Cushing, Oklahoma and would be constructed concurrently with the proposed Project.
Cushing Marketlink Project (planned)	Two oil storage tanks and associated equipment at the proposed Cushing tank farm to store and inject oil from producers in Oklahoma into the proposed Project pipeline.	Oklahoma	The Cushing Marketlink project would be within the PCIC near Cushing, Oklahoma and would be constructed concurrently with the proposed Project.
Enterprise Product Onshore Pipeline System (existing and under construction)	A system of approximately 4,400 miles of onshore crude oil pipelines and 10.5 million barrels of crude oil storage. A new crude oil terminal on an industrial site in southeast Houston is under construction and planned to begin operation in 2012.	New Mexico, Texas, and Oklahoma	Portions of the Enterprise Product System would be within the PCIC near Cushing, Oklahoma. Facilities associated with the proposed crude oil terminal in southeast Houston would be near the PCIC.
True Company Pipelines and Crude Oil Storage Facility (existing)	A system of more than 3,400 miles of crude oil gathering and transportation pipelines, including Bridger Pipeline, LLC that owns and operates the Poplar, Little Missouri, Powder River, Belle Fourche, and Bridger pipeline systems. Three collector pipelines to transport production from the north, west and east into the Butte Pipeline near Baker are under construction.	Wyoming, Montana, and North Dakota	Portions of the True Companies pipeline system would be within the PCIC in eastern Montana.

TABLE 3.14.2-1 Representative Projects Considered in the Cumulative Impacts Assessment[a]			
Project Name (Status)	**Description**	**States Crossed**	**Relationship to Proposed Project**
Enbridge Monarch Pipeline (planned)	Planned 24-inch-diameter pipeline from the Enbridge oil terminal in Cushing, Oklahoma to the Texas Gulf Coast. The initial capacity would be approximately 150,000 bpd, with the ability to expand to about 350,000 bpd. The project would transport light crude oil from Cushing to refineries in PADD III.	Oklahoma and Texas	Portions of the Monarch Pipeline would be in the PCIC in the Cushing, Oklahoma area and would likely be in the PCIC in the vicinity of delivery points in Texas. The route of the Monarch pipeline has not been announced, but other portions of the route may also be within the PCIC. It is possible that the Monarch pipeline would be constructed at about the same time as the proposed Gulf Coast Segment and Houston Lateral.
Basin Pipeline System (existing and proposed)	A 519-mile-long interstate crude oil system with a capacity ranging from about 144,000 and 400,000 bpd and about 5.5 million barrels of storage along the system. Basin proposed to increase pumping in the system to increase throughput. Modification began in 2011, with completion expected in early 2012.	New Mexico, Texas, and Oklahoma	Portions of the Basin system would be in the PCIC in the Cushing, Oklahoma area.
Centurion Pipeline (existing)	2,750 miles of oil-gathering pipelines with a throughput capacity of about 350,000 bpd and 5 million barrels of storage capability. The system also has 64four truck unloading facilities along the route.	New Mexico, Oklahoma, and Texas	Portions of the Centurion Pipeline system would be in the PCIC in the Cushing, Oklahoma area.
Seaway Pipeline (existing)	A 530-mile-long, 30-inch-diameter pipeline with a capacity of about 430,000 bpd.	Texas and Oklahoma	Portions of the Seaway Pipeline would be within the PCIC in the Cushing, Oklahoma area.
Natural Gas Pipelines			
Williston Basin Interstate Pipeline Company System (existing)	A 3,364-mile-long natural gas pipeline transmission system.	Montana, North Dakota, South Dakota, Wyoming, Colorado, and Kansas	Portions of the Williston Basin System would be within the PCIC in eastern Montana and northwestern South Dakota.

TABLE 3.14.2-1 Representative Projects Considered in the Cumulative Impacts Assessment[a]			
Project Name (Status)	**Description**	**States Crossed**	**Relationship to Proposed Project**
Northern Border Pipeline (existing)	A 1,249-mile-long interstate natural gas pipeline with a design capacity of approximately 2.4 billion cubic feet of gas per day (bcfd).	Montana, North Dakota, South Dakota, Minnesota, Iowa, Illinois, and Indiana	Portions of the Northern Border Pipeline would be in the PCIC in northeastern Montana and would be near and parallel to the proposed pipeline for approximately 21.5 miles.
Enterprise Product Onshore Pipeline System (existing)	A natural gas pipeline system that includes approximately 19,200 miles of natural gas pipelines, including about 6,560 miles in Texas.	Alabama, Colorado, Louisiana, Mississippi, New Mexico, Texas, and Wyoming	Portions of the Enterprise Product System would be in the PCIC near or within the Beaumont/Orange area and in the area southeast of Houston area
Northern Natural Gas (existing)	A network of approximately 15,141 miles of natural gas pipelines.	Minnesota, Wisconsin, Michigan, Iowa, South Dakota, Illinois, Nebraska, Kansas, Oklahoma, and Texas	Portions of the Northern Natural Gas pipeline system would be within the PCIC in Nebraska, South Dakota, and Montana.
Natural Gas Pipeline of America (Existing)	Approximately 9,800 miles of natural gas transmission system	Illinois, Iowa, Nebraska, Kansas, Oklahoma, Texas, New Mexico, Missouri, and Arkansas	Portions of the Natural Gas Pipeline System of America would be within the PCIC in Texas and Oklahoma.
Oklahoma Natural Gas Company System (existing)	Approximately 2,500 miles of transmission pipeline.	Oklahoma	Portions of the Oklahoma Natural Gas system would be within the PCIC in Oklahoma.
Lone Star Pipeline System (existing)	Approximately 7,746 miles of gathering and transmission pipelines.	Texas	Short distances of the Lone Star system may be within the PCIC.
Transco Pipeline System (existing)	Approximately 10,560 miles of transmission pipeline with a system design capacity of approximately 8.1 bcfd.	Texas, Louisiana, Mississippi, Alabama, Georgia, South Carolina, North Carolina, Virginia, Maryland, Pennsylvania, New Jersey, and New York	Portions of the Transco system would be within the PCIC in Texas.
Gulf Crossing Pipeline (existing)	Approximately 374-mile-long, 42-inch-diameter, interstate natural gas pipeline with a capacity of approximately 1.73 bcfd.	Oklahoma, Texas, Louisiana, and Mississippi	Portions of the Gulf Crossing Pipeline would be within the PCIC in Oklahoma and Texas and would be parallel and near the proposed Project ROW between Lamar County, Texas, and Bryan County, Oklahoma.
Golden Pass Pipeline (existing)	Approximately 69 miles of 42-inch-diameter pipeline with a transportation capacity of about 2.5 bcfd.	Texas, Louisiana	Portions of the Golden Pass Pipeline would be located within the PCIC along the Gulf Coast Segment in Texas.
Bison Natural Gas Pipeline (under construction)	A 301-mile-long, 30-inch-diameter pipeline with a capacity of 500 million cubic feet per day (mcfd).	Wyoming, Montana, and North Dakota	Portions of the Bison pipeline would be located within the PCIC in Fallon County, Montana.

TABLE 3.14.2-1 Representative Projects Considered in the Cumulative Impacts Assessment[a]			
Project Name (Status)	**Description**	**States Crossed**	**Relationship to Proposed Project**
Mid-Continent Express Pipeline (MEP; existing)	A 506-mile-long, 42-inch-diameter interstate natural gas transmission pipeline with a capacity of about 1.8 bcfd in the western portion of the project.	Southeastern Oklahoma, northeaster Texas, Louisiana, and Alabama	Portions of the MEP would be within or adjacent to the PCIC in Bryan County, Oklahoma and Lamar County, Texas.
Rockies Express West (REX-W; existing)	A 713-mile-long 42-inch-diameter interstate natural gas transmission pipeline with a capacity of approximately 1.5 bcfd. The project includes 5 compressor stations.	Colorado, Wyoming, southern Nebraska, northeastern Kansas, and northern Missouri	REX-W would cross a portion of the PCIC in a generally west-to-west direction in the vicinity of Steele City, Nebraska.
Carbon Dioxide Pipelines			
Green Pipeline (under construction)	Approximately 320-mile-long, 24-inch-diameter pipeline. Transport capacity will be 800 mcfd. Anticipated in-service date is mid 2011.	Louisiana, Texas	Portions of this pipeline would be within the PCIC in Texas and would be collocated with the proposed Project for approximately 46 miles between Beaumont, Texas, to the start of the Houston Lateral.
Water Delivery Systems			
Dry Prairie Rural Water System (under construction)	System to provide drinking water to approximately 27,434 people in eastern Montana. The system will consist of 12- to 15-inch-diameter PVC water delivery pipelines throughout the service area. Planned completion of the overall system is 2011.	Montana	Portions of the water system west of the Fort Peck Indian Reservation may be within the PCIC in northeastern Montana.
Electrical Transmission Lines			
Mountain States Intertie Project (MSTI; proposed)	Approximately 430 miles of 500-kV electrical transmission line from Townsend, Montana to Midpoint, Idaho. Estimated in-service date is 2013.	Montana and Idaho	The MSTI Project would be in western Montana and would not be within the PCIC.
Nebraska Public Power District (proposed)	Upgrades to the existing transmission system, including more than 140 miles of 345-kV and 115-kV transmission lines. Estimated in-service date is mid 2012.	Nebraska, Kansas	Portions of the Nebraska Public Power transmission system would be within the PCIC in Nebraska.
Chinook Project (proposed)	A 500-kV electrical transmission line over 1,000 miles long. Est. in-service date is 2015.	Montana, Idaho, Nevada	The Chinook Project would be located in west central Montana and would not be within the PCIC.

TABLE 3.14.2-1 Representative Projects Considered in the Cumulative Impacts Assessment[a]			
Project Name (Status)	**Description**	**States Crossed**	**Relationship to Proposed Project**
Kansas V-Plan (proposed)	Approximately 180 miles of 765-kV transmission line. Estimated in-service date is 2013.	Kansas	The Kansas V-Plan would be west of Wichita, Kansas and would not be within the PCIC.

[a] This table provides basic information on representative key projects in the vicinity of the proposed Project that are existing, under construction, proposed (applications submitted to agencies with jurisdiction) , planned (announced but not proposed), or reasonably foreseeable. It is not intended to provide a listing of all such projects since there are likely hundreds of existing linear and other projects that have contributed to the cumulative impacts within the area in the vicinity of the proposed Project (see Figures 3.14.2-1 through 3.14.2-4).

[b] The proposed Project cumulative impact corridor (PCIC) is generally defined as a 4-mile-wide corridor centered on the proposed pipeline.

3.14.2.1 Cumulative Impacts from Oil Storage and Transportation Systems

Future (Proposed or Announced) Oil Storage and Transportation Systems

Connected Actions to the Proposed Project

Future oil storage and transportation systems in the vicinity of the proposed Project cumulative impact corridor would also contribute to overall cumulative impacts. For example, since publication of the draft EIS, successful open seasons have occurred for two connected actions to the proposed Project. These connected actions are the Bakken Marketlink and Cushing Marketlink Projects. These two proposed projects are addressed as connected actions in Sections 2.5.3, 2.5.4, and 3.15 of this SDEIS and are also considered in this cumulative impacts analysis to the extent possible based on currently available information. The Bakken Marketlink Project would receive crude oil from the Williston Basin in Montana, North Dakota, and Saskatchewan for shipment to PADD II and PADD III. The Williston Basin is experiencing increased oil production, particularly associated with the development of the Bakken shale formation. The Cushing Marketlink Project would receive crude oil from producers in midwestern U.S. states (e.g., Kansas and Oklahoma) for shipment to PADD III. These two projects would include construction and operation of crude oil storage tanks, connecting pipelines, manifolds, metering stations, and associated facilities, and construction could overlap with construction of the proposed Project. Contribution to cumulative effects during construction would primarily comprise additional dust and noise generation, loss of vegetation or crop cover, and minor localized traffic disruptions. The primary contribution to cumulative effects during operations would be increased air emissions from storage tanks. However, Keystone Marketlink would be required to obtain air quality permits for the projects and would have to comply with the emissions limitations of those permits. Additional contributions to cumulative effects would include effects on visual resources in the vicinity of the storage tanks and manifolds, cultural resources, changes in land use, increased tax revenues, and increased employment.

Another potential connected action to the proposed Project, the BakkenLink Pipeline Project, is currently in the assessment stage and may or may not be carried through to construction and operation. The BakkenLink Pipeline Project has concluded an open season, the results of which are unknown at the time this EIS was prepared. Should this project become economically feasible in the future, it would include a network of pipelines that would collect crude oil from producers at multiple points across the Bakken oil field in the Williston Basin in Montana and North Dakota and deliver up to 100,000 bpd of this crude to the proposed Bakken Marketlink Project. This project would include construction and operation of a new 305-mile-long crude oil pipeline system in western and southwestern North Dakota that would connect areas of the oil field in the Williston Basin to the proposed Bakken Marketlink Project near Baker,

Montana. Should this project be implemented at some future time, its contribution to cumulative effects would be similar to those of the proposed Project but would only occur in that portion of the BakkenLink Pipeline Project within the vicinity of the proposed Project cumulative impact corridor. Any indirect or induced effects of the BakkenLink Pipeline Project (e.g., potentially accelerating the development of crude oil resources in Montana and North Dakota) would be assessed in a future environmental review if the project were to seek regulatory approval at some future time.

Other Projects

Enbridge, Inc. is implementing a reversal of its existing Portal Link pipeline in North Dakota that would provide an on-ramp for Williston Basin oil production to its existing Enbridge Mainline pipeline in Saskatchewan. The reversal is expected to be completed in 2011. In late 2010, Enbridge announced plans for its 24-inch-diameter Monarch pipeline that would extend from the Enbridge oil terminal in Cushing to the Gulf Coast. The pipeline would have an initial capacity of approximately 150,000 bpd, with the ability to expand to about 350,000 bpd.

No other major future proposed oil pipelines have been identified in the vicinity of the proposed Project cumulative impact corridor. However, should additional oil pipelines be constructed within the Project area, they would likely contribute to potential cumulative impacts associated with habitat fragmentation, land use issues, and viewshed degradation.

There were no changes to the remainder of this subsection of the EIS that are relevant to environmental concerns.

3.14.3 Cumulative Impacts by Resource

There have been no substantive changes to Sections 3.14.3.1 through 3.14.3.7 and therefore they are not included in the SDEIS. The draft EIS subsections can be downloaded at www.keystonepipeline-xl.state.gov.

3.14.3.8 Threatened and Endangered Species

Past cumulative effects for threatened and endangered species present near the proposed Project have included habitat loss , alteration, and fragmentation primarily due to agricultural, silvicultural, industrial, urban and suburban development; reduced water quantity and blockage of fish migrations from impoundment and diversion for agricultural or urban use; and reduced water quality from degradation of riparian habitats and contamination from agricultural, industrial, urban, and suburban runoff. Such cumulative impacts have led to the overall decline and resulting determination of the “protected” or “concern” status for some animals and plants that occur within the vicinity of the proposed Project.

A number of federally-protected threatened, endangered, proposed-for-listing, and candidate-for-listing species potentially occur in the proposed Project vicinity. These species include 3 mammals, 9 birds, 1 amphibian, 6 reptiles, 4 fish, 2 invertebrates, and 6 plants (see Section 3.8). Further review of the 24 federally-protected species indicates that the proposed Project would likely adversely affect 1 species, would not likely adversely affect 11 species with implementation of proposed conservation measures, and would have no effect on 12 species. Of the 7 federal candidate species identified within the proposed Project vicinity, it has been determined that 5 candidate species would not likely be present in the affected area and the habitat for 2 candidate species would likely be disturbed or altered.

Incremental loss or alteration of black-tailed prairie dog colonies through prior project construction and operation in addition to similar effects from the proposed Project could lead to cumulative impacts on the

black-footed ferret and the mountain plover in Montana and South Dakota. However, the black-tailed prairie dog colonies that would be crossed by the proposed Project were determined to be too small to support black footed ferrets. Short-, medium-, or long-term loss or alteration of native grassland and sagebrush habitats through the spread of invasive plants in Montana and South Dakota from previous projects in addition to similar impacts from the proposed Project could contribute to cumulative habitat impacts for federal candidate-for-listing birds, including the greater sage-grouse and Sprague's pipit.

The proposed Project could potentially affect 5 migratory birds within their migration range from Texas to Montana and/or within their breeding habitats. Conservation measures proposed for 3 of these birds (i.e., whooping crane, piping plover, and interior least tern) include protection of river and riparian nesting and migration staging habitats through use of HDD crossing methods and site-specific surveys to avoid disturbance to migration staging, nesting, and brood-rearing individuals. Habitat and disturbance impacts at major river crossings from future linear projects would likely incorporate similar conservation measures to avoid and minimize affects to these birds. Future electrical power transmission lines and the distribution lines that would serve pump stations and MLVs of the proposed Project or any other future projects could incrementally increase the collision hazard for 5 protected or candidate migratory birds. Cumulative collision mortality affects would be most detrimental to the whooping crane, interior least tern, and piping plover; while perches provided by towers and poles could increase the cumulative predation mortality for ground nesting birds, including the greater sage-grouse, interior least tern, mountain plover, piping plover, and Sprague's pipit.

Incremental impacts to streams and riparian habitats from future linear project construction and the accidental spread of exotic aquatic invasive plants and animals could increase cumulative impacts to threatened and endangered species habitat. Increased competition from invasive species could contribute to cumulative impacts to native freshwater mollusks and prairie stream fishes which have been increasingly recognized as vulnerable. Multiple stream and wetland crossings, especially those associated with small clear springs and streams or freshwater mussel beds, could result in impacts to habitat quality that could in conjunction with the impacts of the proposed Project affect federally-protected aquatic species of conservation concern.

The USFWS has determined that the proposed Project may adversely affect the American burying beetle through direct mortality resulting from pipeline and associated facility construction and through potential long-term habitat alteration resulting from vegetation changes, soil compaction, and pipeline heat dissipation. Conservation measures designed to reduce direct take of American burying beetles would be implemented, although some mortality would likely occur. Compensatory mitigation in the form of contribution to protection of occupied habitat for this species would offset these affects by preventing future losses through conservation of important habitat and populations, thus reducing cumulative impacts on the species. Construction of new pipelines or other ground disturbing projects through southern South Dakota and northcentral Nebraska could contribute to cumulative mortality and loss of habitat. Any additional potential losses within this species would likely require similar conservation methods and mitigations, thus reducing overall cumulative impacts on the American burying beetle.

Implementation of appropriate conservation measures as determined through consultations with federal, state, and local agencies for state-protected sensitive species and federally protected threatened, endangered, or candidate species for the proposed Project and for future projects would include habitat restoration, impact avoidance, and impact minimization which would ameliorate long-term cumulative impacts. Proposed Project reclamation includes restoration of native vegetation and soil conditions and prevention of spread and control of noxious weeds for disturbed areas. Unavoidable alteration and maintenance of vegetation structure to ensure pipeline safety and to allow for visual inspection would result in some conversion of tall shrub and forested habitats to herbaceous habitats. These conversions

are not expected to adversely affect or contribute to cumulative impacts for any federally protected threatened or endangered species.

3.14.3.9 Noise

There have been no substantive changes to this section and therefore it is not included in the SDEIS. The draft EIS subsection can be downloaded at www.keystonepipeline-xl.state.gov.

3.14.3.10 Land Use

There have been no substantive changes to this section and therefore it is not included in the SDEIS. The draft EIS subsection can be downloaded at www.keystonepipeline-xl.state.gov.

3.14.3.11 Visual Resources

There have been no substantive changes to this section and therefore it is not included in the SDEIS. The draft EIS subsection can be downloaded at www.keystonepipeline-xl.state.gov.

3.14.3.12 Socioeconomics

The proposed Project area is predominantly rural and sparsely populated, with the population tending to increase from north to south along the proposed Project corridor. The population density in northern Montana is less than 1 person per square mile. In the southern Oklahoma/northeastern Texas area, population density ranges from 35 to 40 people per square mile. In areas in southern Texas, population densities range from 50 to 280 people per square mile along the Gulf Coast Segment to nearly 2,000 people per mile in the urbanized areas at the western end of the Houston Lateral.

The presence of temporary construction workers requiring housing and other services would be the primary contribution of the proposed Project to cumulative socioeconomic impacts. Construction workers would likely utilize the closest available local rental, motel/hotel, RV and camping facilities during the construction of each spread. Since adequate temporary housing and services appear to be present along the Gulf Coast Segment and the Houston Lateral, the contribution to cumulative socioeconomic impacts in these areas would be short-term and minor. Along the Steele City Segment of the proposed Project, short-term contribution to housing shortages would be mitigated through construction and operation of four temporary construction camps in Montana and South Dakota.

Additional short-term contribution to cumulative socioeconomic impacts would result from increased employment opportunities and related labor income benefits, and increased government revenues associated with sales and payroll taxes. The primary long-term contribution to cumulative socioeconomic impacts in these areas would include limited employment and income benefits resulting from a very small permanent proposed Project operations staff and some local proposed Project expenditures, as well as an increased property tax base and associated tax revenues. Operation of the proposed Project would require relatively few permanent employees; thus, there would be little contribution to long-term cumulative impacts on population, housing, municipal services, or traffic in the proposed Project area. The increased tax revenue paid to the state and local governments over the life of the spectrum of projects in the proposed Project vicinity would result in beneficial long-term cumulative economic impacts. Keystone estimates that $138.4 million in annual property tax revenues would be generated by the proposed Project in the region of influence. This estimate is based on 2006 tax rates and an estimated $7.0 billion of capital costs. It should be noted that these revenues may increase since the current estimate of proposed Project capital cost has been raised to an estimated $9.0 billion.

Environmental Justice Considerations

As described in Section 3.10.1 of this SDEIS and summarized below, DOS identified minority and low-income populations within a 4-mile-wide corridor centered on the proposed pipeline centerline to determine potential impacts to these populations.

In the analysis, 287 census block groups were identified either partially or totally within the 4-mile-wide environmental justice analysis area, and the percentage of each census block group's population represented by each U.S. Census Bureau minority classification (i.e., each race, aggregate race minority population, and Hispanic/Latino ethnic origin) was calculated. Towns and cities within and near the analysis area with minority populations and low-income populations meaningfully greater than state-wide averages were also identified (see Figures 3.10.1-1 through 3.10.1-6). In addition, HPSA and/or MUA/P areas were identified in counties with minority and low-income populations along the proposed Project corridor (see Table 3.10.1-18 and Figures 3.10.1-7 through 3.10.1-13). Cumulative impacts to minority and low-income populations related to past and reasonably foreseeable future projects could occur, particularly if future projects place additional demands on medical services in HPSA and/or MUA/P areas. However, the contribution of the proposed Project to these cumulative impacts would be minor since the permanent workforce associated with the proposed Project is very small.

Several commenters on the draft EIS expressed concern that there would be indirect cumulative adverse impact to minority and low-income populations due to increased or potentially more toxic air emissions associated with the refining of WCSB crude oil within PADD III. DOS has assessed the composition of heavy WCSB crude oils likely to be transported by the proposed Project and compared these crude oils to the typical crude oils currently refined in PADD III (see Section 3.13.5.1). The heavy WCSB crude oils would either displace or replace the heavy crude oils originating from other sources that are currently refined in PADD III.

The more volatile and toxic aromatic components of crude oil are generally of greatest concern when considering the potential health effects from refinery air emissions. In general, lighter crude oils, such as Alaskan North Slope crude oil, have higher concentrations of these more volatile and toxic aromatic fractions than either the WCSB heavy crude oils or the typical heavy crude oils (e.g., Mexican Maya and Venezuelan Bachaquero) currently refined in PADD III. As discussed in Section 3.13.5.1, the WCSB crude oils that would be transported by the proposed Project have characteristics (e.g., sulphur content and heavy metals content) that make them comparable to and of similar quality to the heavy crude oils currently refined in PADD III. Additionally, each refinery would blend individual feedstock streams to generate an optimized crude oil blend prior to initiating the refining process. The blend would be optimized based on the types of crude oil stored at the refinery and available for blending, specific refinery configuration, processing equipment, and desired end product mix. For example, blending WCSB dilbit crude oil with a lighter Middle East crude oil or even with SCO crude oil would create a feed blend for refining that would be similar to West Texas Intermediate crude oil. Regardless of the types of oil, the refineries currently optimize the blend prior to refining and their future blends would likely be similar. Therefore, displacement or replacement of the heavy crude oils currently refined in PADD III refineries with heavy WCSB crude oil transported by the proposed Project would not likely change the overall load of toxic or noxious refinery emissions during either normal operation or during shutdown/startup conditions. As a result, incremental contribution to cumulative health risks of minority or low-income populations would not likely result from the displacement or replacement of heavy crude oil currently refined in PADD III with WCSB heavy crude oil transported by the proposed Project.

3.14.3.13 Cultural Resources

There have been no substantive changes to this section and therefore it is not included in the SDEIS. The draft EIS subsection can be downloaded at www.keystonepipeline-xl.state.gov.

3.14.3.14 Air Quality

This section includes supplemental information on cumulative impacts related to emissions from refineries and from the emission of GHG.

Refineries

While the proposed Project does not include construction, retrofit or operation of any refineries that could receive crude oil transported through the proposed Project, refinery operations could contribute to increased cumulative impacts to air quality in the vicinity of the proposed Project cumulative impact corridor or beyond if changes in the type or quantity of refinery emissions occurred in the future as a direct result of refining crude oil transported by the proposed Project. Such changes could occur if the proposed Project induced construction of a new refinery, induced expansions of capacity in existing refineries, induced existing refineries to add new downstream processing units (such as cokers or fluid catalytic converters), and/or induced the refineries to process a different crude oil slate (e.g., one that was higher in sulfur content and lower in API gravity with different heavy metals content).

As discussed in Sections 1.2 and 1.4 of this SDEIS, crude oil delivered to PADD II and PADD III refineries would replace domestic crude oil supplies processed at these refineries or supplant existing supplies from overseas that are less stable, more costly, or otherwise less desirable to the refineries.

PADD II Refineries

The proposed Project would supply up to 200,000 bpd to the proposed Cushing tank farm in PADD II. While the specific receiving refineries are not known at this time, there are some refineries or geographic areas proximal to the proposed Project that would be more likely to receive crude oil transported through the proposed Project. There are 27 refineries in PADD II that have a 2008 capacity to process over 3.9 million bpd of crude oil (Table 3.14.3-3), and heavy crude oil deliveries to these refineries totaled at least 900,000 bpd in 2008. According to EnSys (2010), the WCSB heavy crude oil deliveries to PADD II totaled 1.22 million bpd in 2009. The majority of the heavy crude oil supply to PADD II is provided via pipelines from Canada.

Crude oil deliveries through the proposed Project to the Cushing tank farm would generally serve refineries in PADD II, which includes 15 states in the Midwest from North Dakota to Oklahoma and east to Ohio. Crude oil refineries in those 15 states including the crude oil capacity for each refinery are presented in Table 3.14.3-3.

In PADD II, expansions and upgrades have been proposed or implemented in Oklahoma (Sinclair), Illinois (WRB Refining and ConocoPhillips Refinery), Michigan (Marathon), and Indiana (Whiting). There is no indication that the availability of oil transported via the proposed Project would directly result in specific expansions of existing refineries and development of new refineries (none have been built in the U.S in 30 years).

TABLE 3.14.3-3 PADD II Refinery Crude Capacity: 2008	
Refineries	**Crude Oil Capacity (thousand bpd)**
ExxonMobil, Joliet, IL	250
Marathon, Robinson, IL	214
PDV Midwest Refining, Lemont, IL	171
WRB Refining, Wood River, IL	322
BP Whiting, IN	420
Countrymark, Mount Vernon, IN	27
Coffeyville Resources, Coffeyville, KS	120
Frontier, El Dorado, KS	135
NCRA, McPherson, KS	88
Marathon, Catlettsburg, KY	250
Somerset. Energy, Somerset, KY (idle)	0
Marathon, Detroit, MI	114
Flint Hills, Saint Paul, MN	330
Marathon, Saint Paul, MN	84
Tesoro, Mandan, ND	60
BP-Husky, Toledo, OH	160
Lima Refining, Lima, OH	170
Marathon, Canton, OH	85
Sunoco, Toledo, OH	175
ConocoPhillips, Ponca City, OK	210
Sinclair, Tulsa, OK	75
Sunoco, Tulsa, OK	90
Valero. Ardmore, OK	92
Ventura, Thomas, OK (idle)	0
Wynnewood Refining, Wynnewood, OK	75
Premcor, Memphis, TN	182
Murphy Oil, Superior, WI	35
PADD II GRAND TOTAL	**3,934**

Source: U.S. Energy Information Administration (EIA), Refining Capacity 2009.

PADD III Refineries

The proposed Project would supply up to 630,000 bpd to customers along the Gulf Coast in PADD III, which covers six states from New Mexico to Alabama. There are 58 refineries in PADD III with a 2008 refining capacity of approximately 8.4 million bpd (Table 3.14.3-4). Heavy crude oil accounted for approximately 2.5 million bpd of the crude oil refined in PADD III in 2008 and the proportion of heavy

crude oil refined is expected to grow. In 2009 PADD III as a whole imported 2.9 million bpd of heavy crude oil (EnSys 2010).

As identified in Table 3.14.3-4, a total of 15 refineries in PADD III would be connected directly to the hubs to which the proposed Project connects. These 15 refineries are in the Houston, Texas; Port Arthur, Texas; and Lake Charles, Louisiana areas, and have a total crude oil capacity of almost 4 million bpd, including over 1.4 million bpd of heavy crude oil capacity (EIA 2009, Purvin & Gertz 2009). Oil transported via the proposed Project could be delivered to other refineries in PADD III through the existing pipeline network that extends throughout those general areas. The other refineries in PADD III have a total crude oil refining capacity of 4.4 million bpd, including approximately 1.1 million bpd of heavy crude oil. Thus, crude oil deliveries from the proposed Project could be processed at any of the refineries with direct or indirect access to the delivery points of the proposed Project.

The crude oil capacity for each refinery in PADD III, including refineries with direct access to the proposed Project, without direct access to the proposed Project, and with possible pipeline connection to the proposed Project, are identified in Table 3.14.3-4.

TABLE 3.14.3-4
PADD III Refinery Crude Capacity: 2008

Refineries	Crude Oil Capacity (thousand bpd)
Gulf Coast Refineries with Direct Pipeline Access to the Proposed Project	
Motiva Enterprises LLC; Port Arthur, TX	285
Total Petrochemicals; Port Arthur, TX	232
Valero Energy Corp.; Port Arthur, TX	289
Exxon Mobil; Beaumont, TX	349
Pasadena Refining; Pasadena, TX	100
Houston Refining (Lyondell); Houston, TX	271
Valero Energy Corp.; Houston, TX	83
Deer Park Refining; Deer Park, TX	330
Exxon Mobil; Baytown, TX	567
BP; Texas City, TX	478
Marathon Oil; Texas City, TX	76
Valero Energy Corp.; Texas City, TX	200
Calcasieu Refining; Lake Charles, LA	53
CITGO; Lake Charles, LA	430
ConocoPhillips; Lake Charles/Westlake, LA	239
Sub-Total Group I	**3,981**
Gulf Coast Refineries in PADD II Without Direct Pipeline Access to the Proposed Project	
Hunt Refining Co.; Tuscaloosa, AL	35
ConocoPhillips; Belle Chasse, LA	247
Exxon Mobil; Baton Rouge, LA	503
Valero Energy Corp.; Krotz Springs, LA	80

TABLE 3.14.3-4 PADD III Refinery Crude Capacity: 2008	
Refineries	**Crude Oil Capacity (thousand bpd)**
Valero Energy Corp.; St. Charles, LA	185
Marathon Oil; Garyville, LA	256
Chalmette Refining; Chalmette, LA	193
Murphy Oil; Meraux, LA	120
Motiva Enterprises LLC; Norco, LA	236
Motiva Enterprises LLC; Convent, LA	235
Placid Refining; Port Allen, LA	56
Shell Chemical; Saint Rose, LA	55
ChevronTexaco; Pascagoula, MS	330
ConocoPhillips; Sweeny, TX	247
CITGO; Corpus Christi, TX	156
Valero Energy Corp.; Three Rivers, TX	96
Flint Hills Resources; Corpus Christi, TX	288
Valero Energy Corp.; Corpus Christi, TX	142
Sub-Total Group 2	**3,460**
Inland PADD III Refineries with Possible Pipeline Connection to the Proposed Project	
Navajo Refining; Artesia, NM	84
WRB Refining; Borger, TX	416
Valero Energy Corp.; Sunray/McKee, TX	171
Alon USA; Big Spring, TX	67
Delek; Tyler, TX	58
Sub-Total Group 3	**526**
Inland PADD III Refineries without Pipeline Access to the Proposed Project	
Other Refineries without Access	449
Sub-Total Group 4	**449**
PADD III GRAND TOTAL	**8,416**

Source: U.S. Energy Information Administration (EIA), Refining Capacity 2009.

There are ongoing or completed major refinery upgrades at several PADD III refineries that would have direct pipeline access to crude oil transported through the proposed Project (i.e., Motiva, Port Arthur; Valero, Texas City; and Total, Port Arthur) and at several PADD III refineries without direct pipeline access (Borger, Texas; Artesia, New Mexico; and Garyville, Louisiana). There are also continuing plans for upgrades in Port Arthur, revived plans for upgrades in St. Charles and Tuscaloosa, Alabama, and smaller-scale upgrades elsewhere designed to increase heavy crude oil refining capacity in PADD III. There is no information that any of these refinery upgrades are being made specifically as a result of the proposed Project, although at least two refineries (Valero, Texas City and Motiva, Port Arthur) have indicated publicly they would receive crude oil from the proposed Project if it is constructed. Both of

those refineries are proceeding with their upgrading, and whether the proposed Project is constructed or not, those refineries would be expected to utilize the upgraded capacity to process a relatively heavier slate of crude oil. When the expansion and upgrade at the Motiva refinery was announced in 2006, the primary stated purpose was to process more heavy crude oils from Saudi Arabia.

Future Projections of Refinery Crude Oil Slates, Expansions and Investments in PADD III

To address the potential that the proposed Project could induce changes in crude oil slates, or induce refinery expansions and capital investments, an independent analysis of various aspects of the proposed Project was commissioned by the DOE Office of Policy and International Affairs (EnSys 2010). This analysis incorporated projections of likely future PADD III refinery operations, including total refinery throughputs and potential refinery expansions and investments (i.e. adding downstream processing units to process a different crude slate) and the average crude slate quality (measured by average API gravity and sulfur content).

The EnSys (2010) report (Appendix A of the SDEIS) assessed seven alternative pipeline expansion scenarios for two separate petroleum product demand outlooks, a Reference outlook (the 2010 U.S. EIA Annual Energy Outlook) and a Low Demand outlook (based on a February-March 2010 EPA study assuming "more aggressive fuel economy standards and policies to address vehicle miles travelled"). The different scenarios examined resulted in a range of projected WCSB crude oil volume refined in PADD III in 2030 from 0.57 million bpd (No Keystone XL Project [KXL] + Hi Asia[16]) to 1.79 million bpd (KXL no TMX), or 7 to 21 percent of total crude oil refined in PADD III. Three of these scenarios have been selected to highlight the potential impacts in PADD III directly attributable to the proposed Project. These three scenarios are: the KXL scenario (assumes the proposed Project is built), the no-KXL scenario (assumes the proposed Project is not built), and the No Expansion scenario (assumes that the proposed Project is not built but the Trans Mountain TMX2 and TMX3 expansions proceed and additional pipeline capacity is constructed in the near-term between PADDs II and III).

As presented in Table 3.14.3-5, the EnSys (2010) results suggest there could be more WCSB crude oil refined in PADD III by 2020 if the proposed Project is implemented as compared to a scenario without the proposed Project. The volume of WCSB crude oil refined in PADD III in 2030 would remain virtually the same with or without the proposed Project. Even with some differences in the total volume of WCSB crude oil refined in PADD III across the three scenarios presented in Table 3.14.3-5, the average API gravity and the average sulphur content of the crude oil slate would be essentially the same with or without the proposed Project. Additionally, these projections suggest that construction of the proposed Project would not be expected to alter market conditions in PADD III to induce construction of a new refinery, to induce expansion of existing refineries, to induce significant differences in investment levels in refinery down-stream processing units, or to induce significant differences in average crude-slate quality. Therefore there would be little, if any, difference in emissions associated with crude oil refining in PADD III with or without the proposed Project.

These results are consistent with certain known attributes of world crude oil markets:

- Refiners in the United States primarily serve the U.S. market for finished transportation fuel (gasoline, diesel, etc.). Thus, total throughput at U.S. refineries is determined largely by the U.S. demand for transportation fuel derived from crude oil. As discussed in Section 4.1 (No Action Alternative), construction of the proposed Project is unlikely to have any significant impact on demand for transportation fuel.

[16] See the EnSys report in Appendix A of this SDEIS for full explanation of individual scenarios assessed.

- Crude oil is a relatively freely exchangeable (fungible) commodity, with low marine-shipping costs, and with prices set within a world market that consumes over 80 million bpd. Therefore shipping 830,000 bpd from a particular source of crude oil to a particular set of refineries would not necessarily have a large impact on the overall crude market or the competitive position of the PADD III refiners relative to that market.
- Refineries are optimized to process a particular crude slate into a particular set of refined products, and it is not easy or economically efficient in the short to medium term for a refinery to make significant changes in its crude slate quality. Thus, refineries (particularly large refineries in the Gulf Coast) typically obtain crude oil from a variety of sources, and blend those crude oils to achieve a consistent crude oil feedstock quality. If a refinery obtains a significant amount of a relatively heavier crude oil compared to what it has been processing, there is significant incentive for that refinery to balance the heavier crude oil with a relatively lighter crude oil to achieve consistent input quality.
- Most of the refineries in PADD III have already made significant capital investments in the downstream processing units necessary to refine a relatively heavier, more sulfurous crude oil blend. As stated previously in Section 1.2.2.3, PADD III has a particularly high heavy crude oil processing capacity in part because Mexico and Venezuela encouraged expansion of the heavy oil refining capacity through joint-venture investments in Gulf Coast refineries to create a more profitable market for their heavy crude oil resources. Having made those investments, to operate the refineries most efficiently, those refineries have significant incentive to seek out a heavier slate of crude oil, regardless of whether there is increased transport capacity to deliver WCSB oil-sands derived crude oils to PADD III. For example, in 2008 and 2009 the fifteen refineries in PADD III that would have direct pipeline access to the proposed Project (which are located in the Houston, Texas; Port Arthur, Texas; and Lake Charles, Louisiana areas) imported 1.25 and 1.07 million bpd respectively of crude oil with a sulfur content higher than 2.5 percent (Table 3.14.3-6). Of those amounts, approximately 600,000 bpd each year was Mexican Maya crude oil, with an API gravity of approximately 22 and sulfur content of approximately 3.4 percent, which is similar to a diluted bitumen product such as Western Canadian Select (although other dilbits also have a slightly higher sulfur content). The EnSys (2010) economic analysis indicates that rather than increasing the total amount of heavy crude oils processed in PADD III, the availability of WCSB crude oils would likely replace heavy crude oils from other sources, particular Mexican Maya, which is projected to decrease dramatically over the next decade.

TABLE 3.14.3-5
Potential PADD III Refinery Operations in 2020 and 2030

Pipeline Construction Scenario	KXL		No KXL		No Exp + P2P3	
	2020	2030	2020	2030	2020	2030
WCSB Oil Sands Crude Oil Refined in PADD III (mbd)	0.59	1.43	0.19	1.39	0.19	1.01
PADD III Total Refinery Throughput (mbd)[a]	8.1	8.5	8.1	8.5	8.1	8.4
WCSB Oil Sands Crude Oil Refined in PADD III (% of total)	7	17	2	16	2	12
PADD III Refinery Investments (cumulative from 2010 in billion $)	25	43	25	43	25	42
PADD III Crude Slate Average API gravity	31.89	30.15	31.98	30.20	31.98	30.36
PADD III Crude Slate Average Sulfur Content (%)	1.47	1.72	1.46	1.72	1.46	1.72

[a] mbd = million barrels per day
Source: EnSys 2010 (see Appendix A of this SDEIS).

TABLE 3.14.3-6 2008-2009 Crude Oil Imports with Average Sulfur Content above 2.5% at PADD III Refineries That Would Have Direct Pipeline Access to Proposed Project			
Year	**Amount (Million bpd)[a]**	**Average API**	**Average Sulfur Content**
2008	1.25	23.5	3.13
2009	1.07	21.85	3.16

[a] bpd = barrels per day
Source: EnSys 2010 (see Appendix A of this SDEIS).

One important measure of crude quality not included in the EnSys analysis is the total content of the BTEX in the crude oil. These volatile and toxic aromatic components of crude oil are of significant concern when considering the potential health effects from refinery air emissions. In general, lighter crude oils, such as Alaskan North Slope crude oil or Brent Blend, tend to have higher concentrations of these more volatile and toxic aromatic fractions than either the WCSB heavy crude oils or the typical heavy crude oils (e.g., Mexican Maya and Venezuelan Bachaquero) currently refined in PADD III. API gravity and total BTEX content for a variety of crude oils produced in the world are presented in Table 3.14.3-7 with a focus on those currently refined in PADD III. The dilbits that would be delivered by the proposed Project have a slightly higher BTEX content than many other heavy crude oils, but a lower BTEX content than Mexican Maya, a crude oil that has been refined in PADD III in large quantities for many years. Additionally, the BTEX content of the dilbits that would be transported by the proposed Project is much lower than that of many lighter crude oils.

TABLE 3.14.3-7 API Gravity and Total BTEX Content for a Variety of Crude Oils Produced in the World and Currently Refined in PADD III		
Crude Name (Origin)	**API Gravity**	**Total BTEX (ppm)[a]**
Western Canadian Select (DilSynBit; Canada)	21.3	7700
Cold Lake Blend (DilBit; Canada)	21.6	9800
BCF 24 (Venezuela)	23.4	5210
Alaska North Slope	25 - 30.89	15,430 – 22,624
Hondo (California)	19.6	6830
Sockeye Sour (California)	18.8	6748
Mexican Maya (Mexico)	21.3 – 21.8	5500-9773
SynCrude Synthetic (Canada)	31.7	13,100
CNRL Light Sweet Synthetic (Canada)	35	9500
West Texas Sour	30.2	20,540
West Texas Intermediate	36.4 – 40.8	9640
South Louisiana	32.72	12,210
Empire (Louisiana)	33.8	6110
Arab Light (Saudi Arabia)	31.3	10,950
Brent Blend (UK)	37.8 – 38.3	20,550
Sakhalin (Russia)	32.3	49,212

[a] The publicly available crude assays for many of the imported heavy oils in the Gulf coast (from Kuwait, Saudi Arabia, etc.) do not include information on total BTEX (benezene, toluene, ethylbenezene, xylenes) content; ppm = parts per million.
Source: Environment Canada 2011.

Some commenters expressed concern regarding the potential impacts of the proposed Project relative to refinery emissions in startup, shutdown, and maintenance (SSM) events. During an SSM event, refinery emissions do not count towards emission limits within the facility CAA permit. A review of Texas Council of Environmental Quality data reveals that a substantial percentage of annual refinery sulfur dioxide emissions (up to approximately 50 percent) could be related to SSM events (TCEQ 2009). Since each refinery would likely blend individual feedstock streams to generate an optimized crude oil blend prior to initiating the refining process, emissions associated with SSM events would result from refining the blend, not the individual crude oil components. Since refineries currently optimize the blend prior to refining, future blends would likely be similar to current blends, regardless of crude oil source. For example, blending the WCSB dilbit and SCO crude oils likely to be transported by the proposed Project would create a feed blend for refining that would be similar to West Texas Intermediate crude oil. Therefore, displacement or replacement of crude oils currently refined in PADD III refineries with WCSB crude oils that would be transported by the proposed Project would not likely change the overall load of toxic or noxious refinery emissions during either normal operation or SSM events.

The EnSys report (2010) assessed seven different WCSB crude oil transportation scenarios under both the EIA Annual Energy Outlook 2010 (AEO) for reference global and U.S. petroleum supply and demand projections, and a low demand outlook provided to DOE by EPA (i.e., a total of 14 scenarios were assessed). According to EnSys, all scenarios assessed resulted "…in very similar U.S. refinery investments, expansions, throughputs, and thus total crude import levels, U.S. product import and export levels, U.S. import costs, U.S. and global refinery CO_2 emissions and global life-cycle GHG emissions. Impacts of changing pipeline assumptions on overall U.S. crude slate quality, U.S. Gulf Coast (PADD3) crude slate and refining activity were also limited" (EnSys 2010). One scenario assessed, the No Expansion pipeline scenario (no expansion beyond existing pipeline capacity from WCSB to the U.S. or elsewhere, which limits WCSB crudes export capacity), would result in the lowest volume of WCSB crude oil delivery to PADD III, approximately 100,000 bpd. Without the proposed Project and additional pipelines from PADD II to PADD III, the crude oil demand balancing supply to PADD III would likely be imported from the Middle East and Africa (EnSys 2010).

Under the EnSys (2010) No Expansion scenario, cumulative refinery investments are similar to the other scenarios in the 2020 timeframe, but approximately 10 percent less than the EnSys (2010) KXL scenario in 2030. PADD III refinery crude throughputs are slightly lower in the EnSys (2010) No Expansion scenario (approximately 300,000 bpd less than the EnSys (2010) KXL scenario), but are offset by corresponding increases in PADD II throughputs, as there is projected expansion there to process the greater supply of "locked-in" WCSB crude in PADD II (approximately 300,000 bpd more than the other scenarios), which would shift any potential, projected refinery expansion in the 20-year time frame from PADD III to PADD II. PADD III crude slate quality was projected to be slightly better in the EnSys (2010) No Expansion scenario, and was also projected to have up to 5 percent less sulfur than the other scenarios (1.42 percent) and to be up to 4 percent lighter in average API gravity (31.29) than the other scenarios.

As explained further elsewhere, the EnSys (2010) report judged the No Expansion scenario to be "unlikely" in large part because the WORLD model indicated that if the proposed Project were not constructed, there was projected market demand to support adding broadly similar additional pipeline capacity, including to the PADD III Gulf Coast. This conclusion may be especially true regarding the addition of pipeline capacity between PADD II and PADD III because there are many fewer regulatory hurdles to the construction of such pipelines, and numerous right-of-ways already exist for pipelines that transport crude oil and refined products from PADD III to PADD II. Also, the EnSys report explicitly excluded examining the possible addition of rail or barge transport capacity. As has been shown by the development of Bakken production infrastructure in Montana and North Dakota (where 200,000 bpd of rail transport capacity is being added over the next 2 years), significant rail capacity can be added

relatively quickly where there is both market demand and constraints on existing pipeline capacity. These observations suggest that the contribution to cumulative air emissions in PADD III resulting from future refinery activities would be independent of the proposed Project (i.e., the total emissions would be similar with or without the proposed Project). Additional information relative to refineries that could receive crude oil transported by the proposed Project is presented below.

The existing refineries processing heavy crude oil in PADD II and PADD III are designed and permitted to refine heavy crude oil. As a result, the processing of heavy crude oil transported via the proposed Project would be required to occur within existing permit thresholds. Permitting of these facilities is under the authority of EPA as the federal agency that implements and enforces the requirements of the CAA. State agencies with delegated authority to administer air quality programs and with approved SIPs include Texas and Louisiana. The permitting process is designed to avoid significant cumulative impacts to regional air quality associated with air emissions. Potential refinery expansions are in various stages of planning and implementation, and each refinery is unique in regard to the size and type of expansion or upgrade, the type of best available control technology (BACT) that has been or would be implemented, the status of the expansions, the availability of air emissions modeling, and the resulting impact of associated emissions relative to existing conditions.

Federal regulations require that refineries undergoing substantial modification must integrate BACT into their design, operation, and emission offsets. In some cases, expansions in refined oil volume in association with BACT modifications can result in decreases in overall emissions, particularly for older refineries using outdated emission controls.

DOS (2009) provided a review of various refinery expansions and upgrades in PADD II associated with increasing the capacity of heavy crude oil processing. Specifically, DOS quantitatively reported on the change in emissions of criteria pollutants associated with proposed refinery expansions in Illinois, Indiana, and Michigan. Any refinery expansions or upgrades at refineries that could receive crude oil from the proposed Project would likely be required to adhere to similar regulatory standards. As a result of improvements in control technologies and the use of offsets, these refinery upgrades and expansions generally resulted in an overall increase in carbon monoxide, and a decrease in emissions of particulate matter, sulfur dioxide, and nitrogen dioxides. Volatile organic emissions tended to decrease slightly, but not consistently. These results indicate that current BACT requirements for expansion of existing refineries with outdated control technologies could result in an overall reduction in emissions relative to baseline conditions for some criteria pollutants.

Cumulative air emissions in PADD III are likely to change over time as a result of ongoing and planned refinery expansions, whether or not the proposed Project is implemented. The largest permitted refinery expansion for processing heavy crude oil in recent years is for the Motiva refinery in Port Arthur, Texas. This expansion would increase the heavy oil refining capacity of Motiva by 325,000 bpd (from 275,000 to 600,000 bpd) with a projected in-service date of 2012. The Motiva refinery would have direct access to the proposed Project and would have the largest heavy oil refining capacity in PADD III. This expansion would result in increases in most criteria pollutants, although there would be a reduction in VOCs (Table 3.14.3-8). The likely reasons that this expansion would result in net increases in most emissions include the overall size of the expansion and the fact that the existing refinery was already using relatively modern emission controls. Any modification to the existing refining processes would therefore not produce emission reductions in the same proportion as would occur for more outdated refineries. Specific emission estimates are unavailable for other refinery expansions under consideration in PADD III.

TABLE 3.14.3-8 Net Emissions for the Motiva Refinery Expansion[a]									
NO_x (tons)	CO (tons)	VOC (tons)	SO_2 (tons)	PM (tons)	C_6H_6 (tons)	H_2SO_4 (tons)	H_2S (tons)	NH_3 (tons)	Cl_2 (tons)
592.74	1,489.53	-116.73	1679.73	464.37	-0.47	22.24	4.33	125.69	3.77

[a] NOx = Oxides of nitrogen; CO = Carbon monoxide; VOC = Volatile organic compounds; SO_2 = Sulfur dioxide; PM = Particulate matter; C_6H_6 = Benzene; H_2SO_4 = Sulfuric acid; NH_3 = Ammonia; Cl_2 = Chlorine.
Source: TCEQ 2009.

Cumulative air impacts along the proposed Project cumulative impact corridor could change if new refineries are constructed in the future, although EnSys (2010) indicates such potential refinery construction is not sensitive to whether the proposed Project is implemented or not. There are currently no new refineries planned within about 500 miles of any delivery point for the proposed Project, although one new refinery is proposed in the northern portion of PADD II, the Hyperion Energy Center in South Dakota. While no new refinery has been permitted and built in the U.S. in the past 30 years, estimates of emissions used in the permitting process for the proposed Hyperion project can be used to allow quantification of potential emissions from upgraded refineries capable of processing heavy crude oil in PADD III that would use modern technology to process heavy crude oil. In fact, the calculated emissions presented in the permitting process for the proposed Hyperion refinery are generally comparable to those calculated for the ongoing 325,000-bpd Motiva expansion. The calculated emissions resulting from processing up to 400,000 bpd for the proposed Hyperion refinery (SDDNR 2008) are:

- 773 tons of NO_X;
- 1,999 tons of CO;
- 863 tons of SO_2;
- 828 tons of VOCs; and
- 1,046 tons of particulate matter (PM).

It is expected that most of the oil transported by the proposed Project would replace historic crude oil supplies or supplant supplies from less stable or more costly sources for the following reasons:

- The maximum volume of oil that would be transported by the proposed Project (830,000 bpd) represents approximately 7 percent of the overall crude oil refining capacity of PADD II and PADD III (over 12 million bpd);
- The supply of domestic crude oil is substantially diminished and in relative decline (although it increased in 2010 based on increased production from the Bakken shale in North Dakota and Montana, and from offshore extraction);
- The current supply of heavy crude oil delivered to PADD III from current overseas sources is either declining or at risk for political reasons; and
- There is a well developed existing regional infrastructure to facilitate distribution of crude oil transported by the proposed Project among existing PADD II and PADD III refineries.

Although the EnSys (2010) results indicate that the construction of the proposed Project is not likely to impact imported amounts of WCSB crude oil or refinery emissions, the following hypothetical emissions estimate is presented for illustrative purposes. A conservative hypothetical maximum emissions estimate could be developed by assuming that the entire crude oil volume transported by the proposed Project

would be heavy crude oil and that it would be refined at upgraded refineries. Using the emissions estimates discussed above for the Motiva refinery upgrade and the proposed Hyperion refinery project, this hypothetical maximum emissions estimate can be calculated by multiplying the maximum proposed Project throughput (830,000 bpd) by the emission rates per barrel reported for Motiva or Hyperion since these refineries are assumed to be typical for recently upgraded refineries implementing BACT. Hypothetical maximum annual emissions of NO_X would range between about 1,514 and 1,604 tons, CO emissions would range between about 3,804 and 4,148 tons; SO_2 emissions would range between about 1,791 and 4,290 tons, particulate matter emissions would range between 1,186 and 2,170 tons, and VOC emissions would be about 1,718 tons. However, since the crude oil transported by the proposed Project would be replacing or displacing crude oil from other sources, the majority of the emissions generated from refining crude oil transported by the proposed Project would not result in incremental increases to refinery emissions in either PADD II or PADD III. Additionally, it is expected that approximately one-third of the volume transported by the proposed Project would not be heavy crude oil, particularly in light of the proposed Bakken Marketlink and Cushing Marketlink connected actions.

End Use

Some commenters on the draft EIS expressed concerns relative to indirect contributions to cumulative air quality impacts related to the combustion or other use of petroleum products refined from the crude oil that would be transported to PADDs II and III by the proposed Project. The end use of refined petroleum products could include combustion (e.g., vehicles, power generation, or other industrial facilities) or non-combustion uses (e.g., asphalt, petroleum coke, liquefied refinery gases, and lubricants). The ultimate use of refined product originating from crude oil transported by the proposed Project would not produce different end use emissions. Criteria pollutant emissions from consumer and manufacturing use of refined petroleum products are regulated under permits for some uses (e.g., mass transportation vehicles and petrochemical processing) and not for others (e.g., private vehicles) beyond standard quality rules designed to reduce pollutants (e.g., oxygenated fuels, low-sulfur diesel, CAFÉ standards). For instance, the CAFÉ regulations in the United States, first enacted by Congress in 1975, are federal regulations intended to improve the average fuel economy of cars and light trucks (trucks, vans and sport utility vehicles) sold in the U.S. In 2011, the standard changes to include many larger vehicles.

Greenhouse Gases and Climate Change

Contribution to cumulative impacts from GHG would result directly from construction and operation of the proposed Project. Contribution to cumulative impacts from GHG could also result from activities indirectly related to the proposed Project (e.g., crude oil extraction, refining, and refined product end uses) if those activities were affected by the proposed Project. Many commenters expressed concern on the level of analysis within the draft EIS concerning indirect GHG impacts from production in the WCSB oil sands, from refining the WCSB crude oil that would be transported by the proposed Project, and from end uses of refined products originating from that crude oil. The principal GHG are carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), ozone, and water vapor. The reference gas for climate change is CO_2 and, therefore, measures of non-CO_2 GHGs are converted into CO_2-equivalent (CO_2-e) values based on their potential to absorb heat in the atmosphere. The principal GHG of concern related to the proposed Project is CO_2, which enters the atmosphere through the burning of fossil fuels (e.g., oil, natural gas, and coal), solid waste, and trees and wood products, and as a result of other chemical reactions (e.g., manufacture of cement). CO_2 is removed from the atmosphere (or "sequestered") when it is absorbed by plants as part of the biological carbon cycle or through other natural and anthropogenic methods.

Climate change is defined by the United Nations Framework Convention on Climate Change as "a change of climate which is attributed directly or indirectly to human activity that alters the composition of the

global atmosphere and which is in addition to natural climate variability observed over comparable time periods" (EPA 2008). Natural processes (e.g., changes in the sun's intensity, slow changes in the Earth's orbit around the sun, animal respiration, and changes in ocean circulation) and human activities (e.g., fossil fuel combustion, deforestation, reforestation, and urbanization) affect emissions of GHG. The accumulation of GHG in the atmosphere affects the Earth's temperature; however, emissions from human activities have caused the concentrations of heat-trapping GHG to increase significantly in the atmosphere. These gases prevent heat from escaping to space, somewhat like the glass panels of a greenhouse. This accumulation has contributed to an increase in the temperature of the Earth's atmosphere and to climate change. If GHG continue to increase, climate models predict that the average temperature at the Earth's surface could increase from 3.2 to 7.2 ºF above 1990 levels by the end of this century (IPCC 2007). Most scientists agree that human activities are changing the composition of the atmosphere, and that increasing the concentration of GHG affects climate change. The rate, intensity, and effects of climate change continue to be assessed. For example, the increased concentration of CO_2 in the atmosphere has increased ocean acidity since pre-industrial times (EPA 2009). The extent of ocean acidification is correlated with atmospheric CO_2 concentration. Ocean acidification affects future climate change by diminishing the ocean's capacity to absorb increasing atmospheric CO_2.

Regulations and Standards Relating to Greenhouse Gases

Federal Programs

On April 2, 2007, in Massachusetts v. EPA, 549 U.S. 497, the Supreme Court found that GHG are air pollutants covered by the CAA. The Court held that the EPA Administrator must determine whether or not emissions of GHG from new motor vehicles cause or contribute to air pollution which may reasonably be anticipated to endanger public health or welfare, or whether the science is too uncertain to make a reasoned decision. In making these decisions, the Administrator is required to follow the language of Section 202(a) of the CAA. The Supreme Court decision resulted from a petition for rulemaking under Section 202(a) filed by more than a dozen environmental, renewable energy, and other organizations. As a result of this decision, on April 24, 2009, the EPA proposed the Endangerment and Cause or Contribute Findings for Greenhouse Gases under the CAA to find that the current and projected concentrations of the mix of six key GHG (CO_2, CH_4, N_2O, HFC, PFC, and SF_6) in the atmosphere threaten the public health and welfare of current and future generations. This is referred to as the endangerment finding. The Administrator is further proposing to find that the combined emissions of CO_2, CH_4, N_2O, and HFC from new motor vehicles and motor vehicle engines contribute to the atmospheric concentrations of these key GHG and hence to the threat of climate change. This is referred to as the cause or contribute finding. This proposed action, as well as any final action in the future, would not itself impose any requirements on industry or other entities. An endangerment finding under one provision of the CAA would not by itself automatically trigger regulation under the entire Act.

On October 30, 2009, the EPA promulgated the first comprehensive national system for reporting emissions of CO_2 and other GHG produced by major sources in the United States. Through this new reporting, EPA will have comprehensive and accurate data about the production of GHG in order to confront climate change. Approximately 13,000 facilities, accounting for about 85 to 90 percent of industrial GHG emitted in the United States are covered under the rule. The new reporting requirements apply to suppliers of fossil fuel and industrial chemicals, manufacturers of certain motor vehicles and engines (not including light and medium duty on-road vehicles), as well as large direct emitters of GHG with emissions equal to or greater than a threshold of 25,000 metric tpy. This threshold is equivalent to the annual GHG emissions from just over 4,500 passenger vehicles. The direct emission sources covered under the reporting requirement include energy intensive sectors such as cement production, iron and steel production, electricity generation, and oil refineries, among others. The gases covered by the rule are CO_2, CH_4, N_2O, HFC, PFC, SF_6, and other fluorinated gases, including nitrogen trifluoride (NF_3) and

hydrofluorinated ethers (HFE). The first annual report would be submitted to EPA in 2011 for the calendar year 2010, except for vehicle and engine manufacturers, which would begin reporting for model year 2011.

According to the preamble of the rule, the U.S. petroleum and natural gas industry encompasses hundreds of thousands of wells, hundreds of processing facilities, and over a million miles of transmission and distribution pipelines. Crude oil is commonly transported by barge, tanker, rail, truck, and pipeline from production operations and import terminals to petroleum refineries or export terminals. Typical equipment associated with these operations includes storage tanks and pumping stations. The major sources of CH_4 and CO_2 fugitive emissions include releases from tanks and marine vessel loading operations. EPA does not propose to include the crude oil transportation segment of the petroleum and natural gas industry in this rulemaking due to its small contribution to total petroleum and natural gas fugitive emissions (accounting for much less than 1 percent) and the difficulty in defining a facility. The responsibility for reporting would instead be placed on the processing plants and refineries.

On June 2, 2010, the EPA issued a final rule that establishes an approach to addressing GHG emissions from stationary sources under the CAA permitting programs. These stationary sources would be required to obtain permits that would demonstrate they are using the best practices and technologies to minimize GHG emissions. The rule sets thresholds for GHG emissions that define when the CAA permits under the NSR/PSD and the Title V Operating Permits programs are required for new or existing industrial facilities. The rule "tailors" the requirements to limit which facilities will be required to obtain NSR/PSD and Title V permits and cover nearly 70 percent of the national GHG emissions that come from stationary sources, including those from the nation's largest emitters (e.g., power plants, refineries, and cement production facilities).

For sources permitted between January 2, 2011 and June 30, 2011, the rule requires GHG permitting for only sources currently subject to the PSD permitting program (i.e., those that are newly-constructed or modified in a way that significantly increases emissions of a pollutant other than GHG) and that emit GHG emissions of at least 75,000 tpy. In addition, only sources required to have Title V permits for non-GHG pollutants will be required to address GHG as part of their Title V permitting (note: the 75,000 tpy CO_2-e limit does not apply to Title V). For sources constructed between July 1, 2011 and June 30, 2013, the rule requires PSD permitting for first-time new construction projects that emit GHG emissions of at least 100,000 tpy even if they do not exceed the permitting thresholds for any other pollutant. In addition, sources that emit or have the potential to emit at least 100,000 tpy CO_2-e and that undertake a modification that increases net emissions of GHG by at least 75,000 tpy CO_2-e will also be subject to PSD requirements. Under this scenario, operating permit requirements will for the first time apply to sources based on their GHG emissions, even if they would not apply based on emissions of any other pollutant. Facilities that emit at least 100,000 tpy CO_2-e will be subject to Title V permitting requirements. EPA plans further rulemaking that would possibly reduce the permitting thresholds for new and modified sources making changes after June 30, 2013.

On December 2, 2010, the EPA released its guidance for limiting GHG emissions based on the CAA requirement for new and modified emission sources to employ BACT to limit regulated air pollutants. As a result, the guidance focuses on the process that state agencies will use as they are developing permits for individual sources to determine whether there are technologies available and feasible for controlling GHG emissions from those sources. The guidance is not a formal rulemaking and does not establish regulations, but it provides permitting authorities more detail on EPA expectations for the implementation of its new GHG permitting requirements.

On April 1, 2010, the EPA and USDOT finalized a new joint regulation for GHG emissions and fuel economy for model years 2012 through 2016 light duty vehicles. The EPA regulates GHG emissions

from passenger vehicles up to 8,500 pounds gross vehicle weight rating (plus medium-duty SUVs and passenger vans up to 10,000 pounds). The program sets standards for CO_2 emissions on the U.S. federal test procedure. Equivalent Corporate Average Fuel Economy (CAFE) regulations, measured in miles per gallon of fuel consumed, were simultaneously established by the USDOT National Highway Traffic and Safety Administration (NHTSA).

State Programs

Programs for GHG emissions are being adopted by some states along the proposed Project corridor. Montana is a member of the Western Climate Initiative (WCI). The WCI is a collaborative effort of seven U.S. states and four Canadian provinces to identify, evaluate, and implement measures to reduce GHG emissions in participating jurisdictions. The WCI has a regional GHG target of 15 percent below 2005 levels by 2020 to be met through a regional market-based multi-sector mechanism, as well as other policies. The recommended cap-and-trade program has a broad scope that includes six GHG (CO_2, CH_4, N_2O, HFC, PFC, and SF_6) and will cover 90 percent of GHG emissions from the region when fully implemented. The cap-and-trade program will begin January 1, 2012.

The Governor of Nebraska, along with 10 other midwestern Governors and 1 Canadian province Premier, is a member of the Energy Security and Climate Stewardship Platform for the midwest. The Platform lists goals for energy efficiency improvements, low-carbon transportation fuel availability, renewable electricity production, and carbon capture and storage development. In addition to goals related to energy efficiency, renewable energy sources, and biofuel production, the Platform lays out objectives with respect to carbon capture and storage (CCS). Members agreed to have in place a regional regulatory framework for CCS by 2010, and by 2012 to have sited and permitted a multi-jurisdiction CO_2 transport pipeline and have in operation at least one commercial-scale coal-powered integrated gasification combined cycle (IGCC) power plant with CCS, with additional plants to follow in succeeding years. By 2020, all new coal plants in the region will capture and store CO_2 emissions. Numerous policy options are described for states to consider as they work towards these goals. The Platform also lays out 6 cooperative regional agreements. These resolutions establish a Carbon Management Infrastructure Partnership, a Midwestern Biobased Product Procurement System, coordination across the region for biofuels development, and a working group to pursue a collaborative, multi-jurisdictional transmission initiative. States adopting all or part of the Platform include Wisconsin, Minnesota, South Dakota, Illinois, Indiana, Iowa, Kansas, Michigan, Missouri, Nebraska, North Dakota, and Ohio, as well as the Canadian Province of Manitoba.

Kansas, on November 15, 2007, joined 5 other states and one Canadian province to establish the Midwestern Regional Greenhouse Gas Reduction Accord. Under the Accord, members agree to establish regional GHG reduction targets, including a long-term target of 60 to 80 percent below current emissions levels, and to develop a multi-sector cap-and-trade system to help meet the targets. Participants also establish a GHG emissions reductions tracking system and implement other policies, such as low-carbon fuel standards, to aid in reducing emissions.

In South Dakota, on February 21, 2008, Governor Mike Rounds signed into law HB 1272, which established a voluntary Renewable Portfolio objective of 10 percent by 2015. Oklahoma and Texas currently do not have state initiatives addressing the reduction in GHG, although Senate Bill 184 required the Texas Commission on Environmental Quality (TCEQ) to develop and present a report to the legislature by December 31, 2010, recommending strategies to reduce the GHG emissions by businesses and consumers of the state.

Low Carbon Fuel Standard

The first low carbon fuel standards (LCFS) were enacted in California in 2007. Since then, other jurisdictions (e.g. British Columbia and the European Union) have enacted similar standards. These standards generally require that overall carbon values for transportation fuels decrease by 10 percent over the next decade, although the definition of fuels and the percent reduction over time differ across jurisdictions. More carbon-intensive fuels include those derived from crude oil sources in the WCSB, Venezuela, Nigeria, the Middle East, and California (IHS CERA 2010). The impact of LCFS on U.S. market demand for oil sands crude oil is speculative at this time since few jurisdictions have implemented these standards. Barr (2010) analyzed the potential for the implementation of an LCFS policy to actually result in an increase in GHG emissions because of a "shuffling," where the fuels sector would support the most inexpensive avenues to comply with the LCFS, thereby shuffling production and sales that may double GHG emissions resulting from crude oil transport to and from areas affected by the LCFS policy. The report suggests that an approved LCFS would result in increased GHG emissions based on a reduction of crude oil imported from Canada and subsequent rerouting of crude imports and exports to account for this displacement. If LCFS were increasingly required in the U.S., this would be expected to discourage overall U.S. imports of oil sands crude from Canada, and in turn would encourage importing of crude oil to the U.S. from areas that produce light sweet crude, likely the Middle East. Canadian crude sources would be diverted to other countries not affected by LCFS, and supplies in the U.S. negatively affected by LCFS requirements would be replaced with supplies from more distant parts of the world.

Cumulative Effects of GHG

Neither the federal government nor states crossed by the proposed Project have established thresholds for determining the significance of GHG emissions. While no final thresholds currently exist, this assessment of the direct and indirect contributions of the proposed Project to global GHG emissions was conducted in accordance with CEQ draft guidance for GHG (CEQ 2010) that established a draft threshold for NEPA purposes of 25,000 metric tpy for CO_2-e. There is a general scientific consensus that the cumulative effects of GHG have influenced climate change on a global scale, which is considered a significant cumulative effect.

Construction and Operation Emissions

As discussed in Section 3.12, the GHG emissions during construction of the proposed Project would total approximately 236,978 tpy of CO_2-e over the construction period and direct GHG emissions during proposed Project operation would total approximately 85 tpy of CO_2-e. Indirect GHG emissions associated with electrical generation for the proposed Project pump stations are estimated at approximately 2.6 to 4.4 million tons of CO_2 per year for a proposed initial capacity of 700,000 bpd and a potential capacity of 830,000 bpd, respectively, as calculated using EPA AP-42 emission factor for large diesel engines and assuming 30 pump stations with 79 to 132 pumps rated at 6,500 hp. This contribution to cumulative GHG impacts from proposed Project construction and operation is very small compared to total GHG emissions for the United States (CO_2 equivalents from anthropogenic activities) which totaled 7,054 million tons in 2006, and global CO_2 emissions which totaled 28,193 million tons in 2005 (CO_2 equivalents from fuel combustion) (EPA 2008). Construction activities associated with the proposed Project for each year represent less than 0.003 percent and 0.0008 percent of the national and global GHG emissions, respectively. While the EPA has released proposed regulations that would require approximately 13,000 facilities nationwide to monitor and report their CO_2 and other GHG emissions, the proposed Project would not satisfy the definition of these regulated facilities and there are no federal regulations or guidance to definitively identify the significance of the GHG emissions associated with operation of the Project. Although the GHG emissions associated with construction of the proposed Project would be greater than the CEQ draft threshold of 25,000 tpy of CO_2-e that is suggested as a useful

presumptive threshold for disclosure during NEPA review, the overall contribution to cumulative GHG impacts from proposed Project construction and operation would not constitute a substantive contribution to the U.S. or global emissions.

Indirect Cumulative Impacts and Life Cycle Greenhouse Gas Emissions

The following discussion on GHG life cycle emissions associated with oil sands is provided in response to comments on the draft EIS. DOS is providing this information as a matter of policy, although the proposed Project would not substantively influence the rate or magnitude of oil extraction activities in Canada, or the overall volume of crude oil transported to the U.S. or refined in the U.S. (EnSys 2010). To assist in addressing concerns relative to GHG, the DOS third party contractor requested that ICF International LLC (ICF) a detailed review of key studies in the existing literature that address life-cycle GHG emissions of petroleum products, including petroleum products derived from Canadian oil sands, and a comparison of life cycle GHG emissions reported in the literature for Canadian oil-sands derived crude oil and refined products with those of reference crude oils. A summary of the ICF report is presented in the following sections and the full report is presented in Appendix B of this SDEIS.

Introduction

The EnSys (2010) report commissioned by DOE evaluated potential influences of the proposed Project on global, U.S., and regional oil demand; the effect of that demand on continued or expanded development of WCSB oil sands crude oil sources; and assessments of global life-cycle GHG impacts under 14 separate crude oil transportation scenarios. As a part of that analysis, EnSys estimates the changes in life-cycle GHG emissions resulting from these scenarios, including a "no expansion" scenario (i.e., a scenario in which no additional pipelines beyond those in operation as of late 2010 are constructed to transport crude oil from WCSB). The GHG emissions estimated for each scenario are related to quantities of specific WCSB oil sands-derived crude oils produced and their respective life-cycle GHG intensity. The EnSys (2010) analysis relied on the life-cycle GHG emission factors developed by the DOE National Energy Technology Laboratory (NETL 2008 and NETL 2009).[17] NETL's estimates address a range of the world crude oils consumed in the U.S., including the WCSB oil sands crude oils as well as the "average crude" consumed in the U.S. in 2005.[18] Because the NETL-developed emission factors were selected to be a key input to the EnSys (2010) analysis and to EPA's renewable fuel regulations, they serve as an important reference case for evaluating life-cycle emissions for different crude sources. Thus, while this section provides an assessment of the differences between the life-cycle GHG emissions associated with Canadian oil sands-derived crudes that may be refined in the United States versus reference crudes, it also specifically compares results from other literature against the NETL studies' base case. A more detailed description of the ICF review is provided in Appendix B of this SDEIS.

Life-Cycle Carbon Overview

Evaluating life-cycle emissions provides a method to assess the relative GHG emissions between various sources of crude oil. The life-cycle assessment (LCA) methodology attempts to identify, quantify and track carbon emissions arising from the development and use of a hydrocarbon resource. It is helpful to characterize carbon emissions into what can be considered primary and secondary flows. The primary carbon emissions are associated with the various stages in the life cycle from the extraction of the crude from the reservoir to refining to combustion of the refined fuel products (typically referred to as a "well-

[17] EnSys used factors from the "NETL: Petroleum-Based Fuels Life Cycle Greenhouse Gas Analysis – 2005 Baseline Model," which were applied for each scenario within the DOE version of the Energy Technology Perspective (ETP) model.
[18] This 2005 average serves as the baseline in the U.S. Renewable Fuel Standard Program (EPA 2010).

to-wheels" analysis). The secondary carbon emissions are associated with activities (e.g., land use impacts) not directly related to conversion of the hydrocarbon resource into useful product fuels.

Most of the GHG emissions from hydrocarbon resource development results from three primary steps in the LCA: production of the crude oil, refining of the crude oil, and combustion of the refined products. Transportation of the crude oil to the refinery and transportation of the products to market also contribute to GHG emissions. The primary objective of refining crude oil is to produce three premium refined products: gasoline, diesel, and kerosene/jet fuel. These primary GHG emissions associated with fuel production drive the economics and engineering of the oil business. In addition to the primary emissions arising from the production, transportation, refining, and combustion steps of the LCA, there is a range of secondary carbon emissions to be considered. For example, extracting crude can influence secondary GHG emissions, such as changes in biological or soil carbon stocks resulting from land-use change during mining. In addition to premium fuels, typically 5 to 10 percent of the carbon in the petroleum resource ends up in co-products, such as petroleum coke, that are often (but not always) combusted and converted to CO_2. As discussed in greater detail below, these secondary flows are treated differently across the LCA literature and estimates of specific process inputs and emission factors vary according to the underlying methods and data sources used in each LCA.

The GHG emission factors modeled by NETL are based on a well-to-wheels (WTW) LCA. WTW assessments for petroleum-based fuels focus on the GHG emissions associated with extraction of the crude oil from reservoirs, transportation of crude oils to refineries, refining of the crude oil, distribution of refined product (e.g., gasoline, diesel, and jet fuel) to retail markets, and combustion of these fuels in vehicles or planes. For some WCSB oil sands crude oils, the assessment also addresses upgrading of the extracted crude oil (i.e., partial refining of some oil sands crude oils to produce synthetic crude oil). Other analyses (e.g., well-to-tank [WTT] analyses) establish different life-cycle boundaries and evaluate only the emissions associated with the processes prior to combustion of the refined products. Inclusion of the combustion phase allows for a more complete picture of crude oil contribution to GHG emissions because this phase represents between approximately 70 to 80 percent (depending on crude source) of the WTW emissions (CERA 2010). As a result, a WTW analysis reduces the differential in total GHG emissions between different crude oil sources. Because a WTT analysis focuses on pre-combustion processes, it highlights the differences in upstream life-cycle GHG emissions associated with the extraction, transportation, and refining of crude oils from different sources, as illustrated in a comparison of Figures 3.14.3-1 and 3.14.3-2.

Scope of Review of Life-cycle Studies

A list of the reports reviewed for this assessment is presented in Table 3.14.3-9. The primary studies and additional supplemental reports for the assessment were selected on the following basis:

- The reports evaluate WCSB oil sands crude oils in comparison to crude oils from other sources;
- The reports focus on GHG impacts throughout the life-cycle of crude oils and their related products;
- The reports were published within the last 10 years, and most were published within the last five years;
- The reports represent the perspectives of various stakeholders, including industry, governmental organizations, and non-governmental organizations; and
- The reports originate from research bodies within the United States, Canada, and international locations.

TABLE 3.14.3-9 Primary and Additional Studies Evaluated [a]	
Primary Studies Analyzed	**Type**
NETL. 2008. Development of Baseline Data and Analysis of Life Cycle Greenhouse Gas Emissions of Petroleum-Based Fuels.	Individual LCA
NETL 2009. An Evaluation of the Extraction, Transport and Refining of Imported Crude Oils and the Impact of Life Cycle Greenhouse Gas Emissions.	Individual LCA
IEA. 2010. World Energy Outlook.	Meta-analysis
IHS CERA. 2010. Oil Sands, Greenhouse Gases, and U.S. Oil Supply: Getting the Numbers Right.	Meta-analysis
NRDC. 2010. GHG Emission Factors for High Carbon Intensity Crude Oils ver. 2.	Meta-analysis
Energy-Redefined LLC for ICCT. 2010. Carbon Intensity of Crude Oil in Europe Crude.	Individual LCA
AERI/Jacobs Consultancy. 2009. Life Cycle Assessment Comparison of North American and Imported Crudes.	Individual LCA
AERI/TIAX LLC. 2009. Comparison of North American and Imported Crude Oil Lifecycle GHG Emissions.	Individual LCA
Charpentier, et al. 2009. Understanding the Canadian Oil Sands Industry's Greenhouse Gas Emissions.	Meta-analysis
Additional Studies/Models Analyzed	**Type**
RAND Corporation. 2008. Unconventional Fossil-Based Fuels: Economic and Environmental Trade-Offs.	Individual LCA
Pembina. 2005. Oil Sands Fever: The Environmental Implications of Canada's Oil Sands Rush.	Partial LCA
Pembina. 2006. Carbon Neutral 2020: A Leadership Opportunity in Canada's Oil Sands. Oil sands issue paper 2.	Partial LCA
McCann and Associates. 2001. Typical Heavy Crude and Bitumen Derivative Greenhouse Gas Life Cycles.	Individual LCA
Pembina. 2011. Life cycle assessments of oil sands greenhouse gas emissions: A checklist for robust analysis.	White Paper
GHGenius. 2010. GHGenius Model, Version 3.19. Natural Resources Canada.	Model
GREET. 2010. Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation Model, Version 1.8d.1. Argonne National Laboratory.	Model

[a] See Appendix B of this SDEIS for more information on each study.

For WCSB oil sands crude oils, the assessment focused on those that could be transported through the proposed Project. Based on this criterion, the solid, raw bitumen from oil sands was eliminated except to the extent that it is included within averaged results (e.g., NETL provides a single WCSB oil sands estimate that represents a weighted average of 43 percent crude bitumen from *in situ* production and 57 percent SCO from mining).

This assessment addresses three types of WCSB oil sands crude oils that are extracted either by mining or the *in-situ* thermal processes. Conventional strip-mining methods are used to extract oil sands deposits that are less than about 75 meters below the surface.[19] To recover deeper deposits of oil sands, *in situ* methods are used. *In situ* recovery methods typically involve injecting steam into an oil sands reservoir to heat – and thus decrease the viscosity of – the bitumen, enabling it to flow out of the reservoir sand matrix to collection wells. Steam is injected using cyclic steam stimulation (CSS), where the same well cycles between periods of steam injection and bitumen production, or by steam-assisted gravity drainage

[19] Mining accounts for roughly 48 percent of total bitumen capacity in the WCSB oil sands as of mid-2010 (IEA 2010, p. 152).

(SAGD), where a pair of horizontal wells is drilled; the top well is used for steam injection, and the bottom well for bitumen production. Due to the high energy demands for steam production, steam injection *in situ* methods are generally more GHG-intensive than mining operations. The WCSB crude oil types assessed in this study are described briefly below:

- Synthetic crude oil (SCO) − SCO is produced from bitumen via a refinery conversion of heavy hydrocarbons to lighter hydrocarbons. While SCO can be sour, it is usually a light, sweet crude oil without heavy fractions.
- Dilbit (diluted bitumen) − Dilbit is bitumen blended with a diluent, usually a natural gas liquid such as condensate, to create a "lighter" product and to reduce viscosity so the dilbit can be transported via pipeline. Dilbit feedstock processing requires more heavy oil conversion capacity than most crude oils.
- Synthetic bitumen (synbit) – Synbit is usually a combination of bitumen and SCO. The properties of synbit blends vary greatly, but blending lighter SCO with heavier bitumen results in a product more similar to conventional crude oil than SCO or dilbit alone.

The reference crudes evaluated in the literature reflect a range of sources and GHG emissions and include:

- The average U.S. barrel consumed in 2005 (from NETL 2008). This reference was selected because it provides a baseline for fuels produced from the average crude consumed in the United States.
- Venezuela Bachaquero and Mexico Maya, which are representative of heavy crudes currently refined in PADD III refineries. It is assumed that these crude oils would be displaced or replaced by the WCSB oil sands crude oil that would be transported by the proposed Project, although it is likely that they would find markets elsewhere and would still be produced.
- Saudi Light (i.e., Middle East Sour), which was taken to be the balancing grade for world crude oil supplies in EnSys (2010). This is the crude that may ultimately be backed out of the world market if additional supply of WCSB oil sands crudes is produced.

Evaluation of Key Factors Influencing the GHG Results

There are many differences in the **study design factors** and **input assumptions** for life-cycle GHG analyses of WCSB oil sands crude oils relative to the four reference crude oils.

Study design factors relate to how the GHG comparison is structured within each study. These factors include the overall purpose and goal of the study, the types of crudes and refined products that are compared to each other, the timeframe over which the results of the study are applicable, the life-cycle boundaries established to make the comparison, the functional units or the basis used for comparing the life-cycle GHGs for crudes or fuels to each other (e.g., expressing GHG emissions per unit of crude, SCO, all refined products, or specific refined products such as gasoline or diesel, in terms of volume, energy, or distance units), and the treatment of co-products other than gasoline, diesel, and jet fuels (e.g., asphalt, petroleum coke, liquefied refinery gases, and lubricants). Some studies allocate a fraction of the GHG emissions from refining to these co-products and exclude these emissions from the life-cycle boundary (i.e., they are not included within the studies' life-cycle results). Other studies include these emissions but assign credits for GHG emissions from other sources that are offset by combustion of the co-products (e.g., electricity exported from a refinery replaces natural gas-fired power generation, and petroleum coke from a refinery replaces coal).

Key design factors across the studies identified through this assessment are summarized in Table 3.14.3-10. In general, the studies reviewed are consistent in their treatment of some factors (e.g., generally excluding emissions associated with land-use changes) but vary in their treatment of other factors (e.g., emissions from petroleum coke and electricity cogeneration). Most studies exclude land-use change and the emissions arising from the construction of capital infrastructure. Importantly, only a few studies modeled the effect that upgrading SCO has on downstream GHG emissions at the refinery. Several (but not all) studies include the following:

- Upstream production of purchased fuels and electricity used to power machinery in the oil fields and at refineries;
- Flaring and venting;
- Fugitive emissions; and
- Methane emissions from oil sands mining and tailings ponds.

Input assumptions impact life-cycle analysis results and assumptions are input at each life-cycle stage. Due to limited data availability and the complexity of and variation in the practices used to extract, process, refine, and transport crude oil, studies often use simplified assumptions to model GHG emissions. For example, for both WCSB oil sands crude oils and reference crude oils, assumptions about how much petroleum coke is produced, stored, and combusted at the upgrader or refinery, and how much is sold to other users, are key drivers of GHG emission estimates. Transportation assumptions have a more limited effect, but vary across the studies. Key input assumptions for WCSB oil-sands-derived crude oils include:

- Type of extraction process (i.e., mining or *in situ* production);
- Steam-oil ratio assumed for *in situ* operations;
- Efficiency of steam generation, and thus its energy consumption; and
- Upgrading processes modeled for SCO and whether or not estimated refinery GHG emissions account for upgrading.

For the reference crudes, key input assumptions include the oil-water and gas-oil ratios that are used to estimate reinjection and venting or flaring requirements, and whether and what type of artificial lift is considered for extracting crude oil.

Life-cycle GHG emissions for gasoline produced from WCSB oil sands crude oils relative to other reference crude oils consumed in the United States, as reported by NETL (2009) are summarized in Table 3.14.3-11. The results are subject to several input assumptions that influence the results of the analysis. These assumptions and their estimated scale of impact on the WTW results are summarized in the last two columns of Table 3.14.3-11.

TABLE 3.14.3-10
Summary of Key Study Design Features that Influence GHG Results

Estimated Relative WTW Impact:[a]		High					Medium				Low
Source	**Data Reference Year(s)**	**Petroleum coke combustion[b]**	**Cogeneration credit[c]**	**Upstream production of fuels included[d]**	**Flaring/ venting GHG emissions included**	**Capital equipment included[e]**	**Methane emissions from tailing ponds included**	**Fugitive leaks included**	**Local and indirect land use change included**	**Refinery emissions account for upgrading[f]**	**Methane emissions from mine face**
NETL 2008	2005	No	NS	Yes	Yes	No	NS	Yes	No	No	NS
NETL 2009	2005	No	NS	Yes	Yes	No	NS	NS	No	No	NS
IEA 2010	2005-2009	NS	NS	Yes	NS	NS	Yes	NS	No	NA	NS
IHS CERA 2010	~2005-2030	V	V	No	NS	NS	V	NS	No	NA	V
NRDC 2010	2006-2010	NS[g]	NS[g]	P	NS	NS	NS	NS	No	NA	NS
ICCT 2010	2009	NS	No	P	Yes	No	NS	Yes	No	No	NS
AERI/Jacobs 2009	2000s	Yes	Yes	Yes	Yes	No	No	No	No	Yes	No
AERI/TIAX 2009	2007-2009	P	P	Yes	Yes	No	Yes	Yes	No	Yes	Yes
Charpentier et al. 2009	1999-2008	NS[g]	NS[g]	V	NS	V	NS	NS	No	NA	NS
RAND 2008	2000s	NS	NS	NS	Yes	No	Yes	Yes	No	No	Yes
Pembina Institute 2005	2000, 2004	NS	NS	NS	P	No	NS	P	No	No	NS
Pembina Institute 2006	2002-2005	NS	NS	No	P	No	Yes	Yes	No	No	Yes
McCann 2001	2007	P	NS	Yes	NS	No	NS	NS	No	NS	NS
GHGenius 2010	Current	Yes	No	Yes	Yes	No	Yes	Yes	Local	NS	Yes
GREET 2010	Current	NS	NS	Yes	Yes	No	NS	Yes	No	NS	NS

Notes: Yes = included in life-cycle boundary; No = not included; P = partially included; NS = not stated; NA = not applicable; V = varies by study addressed in meta-study.

[a] High impact = greater than 3% change in WTW emissions. Medium impact = 1 – 3% change in WTW emissions. Low impact = less than 1% change in WTW emissions.

[b]"Yes" indicates that GHG results for products such as gasoline, diesel, and jet fuel do include petroleum coke production and combustion. "No" indicates that GHG emissions from petroleum coke production and combustion were not included in the system boundary for gasoline, diesel, or jet fuel. The effect of including petroleum coke depends on how much is assumed to be stored at oil sands facilities versus sold or combusted, and whether a credit is included for coke that offsets coal combustion.

[c] "Yes" indicates that the study applied a credit for electricity exported from cogeneration facilities at oil sands operations that offsets electricity produced by other power generation facilities. "No" indicates a credit was not applied. Including a credit for oil sands will reduce the GHG emissions from oil sands crudes relative to reference crudes.

[d] Indicates whether studies included GHG emissions from the production of fuels that are purchased and combusted on-site for process heat and electricity (e.g., natural gas).

[e] Indicates whether the study included GHG emissions from the construction and decommissioning of capital equipment such as buildings, equipment, pipelines, rolling stock.

[f] Indicates whether refinery emissions account for the fuel properties of SCO relative to reference crudes. Since SCO is upgraded before refining, it requires less energy and GHG emissions to refine into gasoline, diesel, and jet fuel products.

[g] Not discussed in the meta-study; may vary by individual studies analyzed.

TABLE 3.14.3-11 GHG Emissions for Producing Gasoline from Different Crude Sources from NETL 2009 and Estimates of the Impact of Key Assumptions on the Oil Sands-U.S. Average Differential							
Life-Cycle Stage	GHG Emissions (g CO2e/MJ LHV gasoline)[a]					Findings on Key Assumptions Influencing Results	
	2005 U.S. Average	Canadian Oil Sands	Venezuela Conventional	Mexico	Saudi Arabia	Description	Estimated Ref Crude WTW Impact[b]
Crude Oil Extraction	6.9	20.4[c]	4.5	7.0	2.5	DOE/NETL uses a weighted average of 43% crude bitumen from in situ production and 57% SCO from mining	NA
Upgrading	NA	IE	NA	NA	NA		
Crude Oil Transport	1.4	0.9	1.2	1.1	2.8	Relative distances vary by study	Low increase or decrease
Refining	9.3	11.5[d]	11.0	12.9	10.4	Did not evaluate impact of upgrading SCO prior to refinery; only affects oil sands.	Medium decrease
Finished Fuel Transport	1.0	0.9	0.9	0.9	0.9	Transportation excluded co-product distribution	Low increase
Total WTT	18.6	33.7	17.6	22.0	16.7		
Fuel Combustion	72.6	72.6	72.6	72.6	72.6	Fuel combustion excluded combustion of petroleum coke and other co-products	Low to high increase[e]
Total WTW	91.2	106.3	90.2	94.6	89.3		
Difference from 2005 U.S. Average	0%	17%	-1%	4%	-2%		

Notes: IE = Included Elsewhere; NA = Not Applicable. LHV = Lower Heating Value. WTT = Well-to-Tank; WTW = Well-to-Wheels.

[a] NETL 2009 values converted from kilograms of CO_2-equivelant per million BTU using conversion factors of 1,055 mega joules per million BTU and 1000 g/kg.

[b] Estimated impact on the WTW GHG emissions for reference crudes, except where noted (i.e., refining assumption affects oil sands), as result of addressing the key assumptions/ missing emission sources. High = greater than approximated 3% change, Medium = approximated 1 – 3% change, and Low = less than approximated 1% change in WTW emissions.

[c] Included within extraction and processing emissions.

[d] Calculated by subtracting other process numbers from WTT total; report missing this data point.

[e] The effect that including petroleum coke combustion has on WTW results depends upon assumptions about the end-use of petroleum coke and whether it is used to offset coal in electricity generation.

For example, NETL (2009) only considered combustion emissions from gasoline, diesel, and kerosene-type jet fuel and allocated the refinery emissions from co-products other than gasoline, diesel, and jet fuel to the co-products themselves. This approach removes the GHG emissions associated with producing and combusting co-products from the study's life-cycle boundary. This approach is consistent with DOE/NETL's objective of estimating the contribution of crude oil sources to the 2005 baseline GHG emissions profile for three transportation fuels (gasoline, diesel, and kerosene-type jet fuel). A portion of the petroleum coke produced from partial refining (upgrading) of WCSB oil sands crudes is stockpiled (sequestered) in Alberta and does not contribute to GHG emissions, whereas virtually all of the petroleum coke produced at U.S. refineries is ultimately combusted. As explained in more detail in the appendix on GHG emissions, if petroleum coke produced from refineries is assumed to offset coal combustion, however, the net emissions from coke combustion will be much smaller. As a result, the effect of

including petroleum coke combustion depends upon study assumptions about the end use of petroleum coke at both the refinery and upgrader, and whether petroleum coke use offsets other fuels, such as coal.

Additionally, the NETL study used linear relationships to relate GHG emissions from refining operations to specific crudes based on API gravity and sulfur content. The study notes that these relationships do not account for the fact that bitumen blends (dilbits and synbits) and SCO in particular will produce different fractions of residuum and light ends than "full-range" crudes. Accounting for the variable properties of these crude oil types and resulting refinery GHG emissions would change the differences between WTW GHG emissions for premium fuels refined from WCSB oil sands-derived crude oils relative to reference crude oils.

GHG Intensity of WCSB Crudes

The wide variation in design and input assumptions within the various studies leads to a wide divergence in calculated GHG emissions. Based on an extensive review of information provided in the studies reviewed, the WTW and WTT GHG emissions of gasoline produced from WCSB oil sands-derived crude oils were compared to similar emission estimates from four reference crude oils (see Figures 3.14.3-1 and 3.14.3-2). Additional information on the data sources and assessment is available in Appendix B of this SDEIS.

As shown in Figure 3.14.3-1, the NETL WTW GHG emission estimates from gasoline produced from WCSB oil sands-derived crude oils are 17 percent higher than that the GHG emission estimates for gasoline produced from the average mix of crude oils consumed in the United States in 2005, and are approximately 19, 13, and 16 percent higher than GHG emission estimates for Middle East Sour, Mexican Heavy (i.e., Mexican Maya), and Venezuelan[20] crude oils, respectively (NETL 2009).

The WTW emission estimates for gasoline produced from SCO via *in situ* methods of oil sands extraction (i.e., SAGD and CSS) in general are higher than the GHG emission estimates for mining extraction methods (Figure 3-14.3-1). This difference is primarily attributable to the energy requirements of producing steam as part of the *in situ* extraction process. According to all of the reviewed studies, gasoline produced from crude oils extracted by both methods produces more life-cycle GHG emissions than gasoline produced from the average mix of crudes consumed in the United States in 2005.

Gasoline produced from dilbit generally has lower estimated GHG life-cycle emissions than gasoline produced from bitumen extracted by mining and *in situ* methods. This is a result of blending raw bitumen with a diluent (e.g., gas condensate) for transport via pipeline. Diluent produces fewer GHG emissions than bitumen, so blending the two together results in lower WTW GHG emissions. This assessment evaluates the refining of both bitumen and diluent at the refinery, since diluent will not be separated from the dilbit blend and recirculated by the proposed Project. WTW GHG emission estimates from gasoline produced from synbit, a blend of SCO and bitumen, are similar to WTW GHG emission estimates for gasoline produced from SCOs produced from bitumen extracted by either mining or *in situ* methods.

Similar trends were evident in the WTT GHG analyses (see Figure 3.14.3-2). The percentage increase in WTT GHG emission estimates for gasoline produced from WCSB oil sands-derived crude oils as compared to gasoline produced from reference crudes (Figure 3.14.3-2) is much larger than the percent increases for WTW GHG emission estimates (Figure 3.14.3-1). Most of the gasoline life-cycle WTW GHG emissions occur during the combustion stage irrespective of the feedstock (i.e., reference crude or oil sands). Because WTT GHG emission estimates do not include the combustion phase, the differences in GHG life-cycle emissions associated with crude oil extraction and refining are emphasized; when

[20] NETL uses Venezuelan Conventional as a reference crude rather than Venezuelan Bachaquero.

expressing the comparison in terms of percentage increases, the same incremental differences in the numerator are divided by a smaller denominator.

The GHG emissions associated with different oil sands extraction, processing, and transportation methods vary by roughly 25 percent on a WTW basis. Life-cycle GHG emission estimates for fuels produced from WCSB oil sands crude oils are higher than emission estimates for fuels produced from lighter crude oils, such as Middle East Sour crudes and the 2005 U.S. average mix. Compared to heavier crude oils from Mexico and Venezuela, WTW emission estimates associated with fuels derived from WCSB oil sand-derived crude oils are 37 percent higher than for SAGD SCO (petroleum coke burned at the upgrader) and 2 percent lower for mining-derived SCO (including storing or selling the petroleum coke).

Incremental GHG Emissions from Oil Sands Crudes Potentially Transported by the Proposed Project Compared to Reference Crudes

As noted earlier in this chapter, based on the EnSys (2010) analysis, under most scenarios the proposed Project would not substantially influence the rate or magnitude of oil extraction activities in Canada, or the overall volume of crude oil transported to the U.S. or refined in the U.S. Thus, from a global perspective, the project is not likely to result in incremental GHG emissions. According to the EnSys (2010) report there is sufficient transboundary pipeline capacity to transport oil sands crudes into the United States through approximately 2020 (although there is not sufficient capacity to meet PADD III market demand).[21] Also, according to the EnSys (2010) report, there is an apparent market demand to put in place pipeline capacity similar to that of the proposed Project if the proposed Project is not implemented. Thus, the proposed Project, if constructed, is unlikely to significantly accelerate displacement of reference crudes. When evaluating the lifecycle GHG emissions of transportation fuels consumed in the United States in a strictly static format, however, it is likely that the lifecyle GHG emissions of transportation fuel produced from WCSB crudes is higher than that of reference crudes. Such an analysis is not strictly necessary for purposes of evaluating the potential environmental impacts attributable to the proposed Project under NEPA, but is relevant and informative for policy-makers to consider in a variety of contexts. For illustrative purposes, this section provides information on the incremental life-cycle GHG emissions (in terms of the U.S. carbon footprint) from WCSB oil sands crudes likely to be transported by the proposed Project (or any transboundary pipeline). The incremental emissions are a function of (1) the throughput of the pipeline, (2) the mix of oil sands crudes imported, and (3) the GHG-intensity of the crudes in the pipeline compared to the crudes they displace. Acknowledging the methodological differences in GHG-intensity estimates between the studies, the weighted-average GHG emissions for selected studies were calculated to estimate the incremental GHG emissions from WCSB oil sands relative to displacing an equivalent volume of reference crudes in U.S. refineries.

NETL (2009), Jacobs (2009), and TIAX (2009) formed the sub-set of studies used to develop weighted averages for purposes of the carbon footprint analysis. These studies are independent analyses of WTW GHG emissions from oil sands and reference crudes that utilize consistent functional units for comparison with each other. The other studies included in this assessment either did not look at the full WTW fuel life-cycle, did not evaluate emissions on a consistent functional unit basis for comparison, or are meta-analyses that include the results of the Jacobs (2009) and TIAX (2009)studies.

[21] Note that a substantial share of these emissions would occur outside of the United States. Also note that the U.S. National Inventory Report, like other national inventories, only characterizes emissions within the national border, rather than using a life-cycle approach. If the United States used a life-cycle approach, upstream emissions from other imported crudes would be attributed to the United States.

For illustrative purposes, Figure 3.14.3-3 shows the percent change in weighted-average GHG emissions from the mix of WCSB oil sands crude oil likely to be transported in the proposed Project relative to each of the four reference crudes. The change in GHG emissions is calculated for the Jacobs (2009) and TIAX (2009) values by weighting the WTW GHG intensity of oil sands crudes by the composition of crudes that could be transported in the proposed Project. For purposes of this assessment, it is expected that 50 percent of pipeline throughput would be SCO, and 50 percent would be dilbit. All WCSB dilbit is currently produced using in situ production and 12 percent of SCO is produced via *in situ* methods (ERCB 2010), yielding a final mix of 50 percent *in situ*-produced dilbit, 44 percent mining-produced SCO, and 6 percent *in situ*-produced SCO.[22] The results are representative of near term expected WCSB oil sands composition and GHG-intensities.

The Canadian oil sands average from NETL (2009) is also plotted on Figure 3.14.3-3 for comparison with Jacobs (2009) and TIAX (2009), although the NETL result assumes a mix of 43 percent crude bitumen and 57 percent SCO. The results show a 2 to 19 percent increase in WTW GHG emissions from the weighted-average mix of oil sands crudes potentially transported in the proposed Project relative to the reference crudes in the near term. Heavier crudes generally take more energy to produce and emit more GHGs than lighter crudes, and in particular, the weighted-average WCSB oil sands crude is currently more energy- and carbon-intensive than lighter crudes like Middle Eastern Sour.

For illustrative purposes, Table 3.14.3-12 shows the incremental annual WTW GHG emissions associated with displacement of 100,000 barrels of each reference crude oil per day (equivalent to 80,000 barrels per day of refined gasoline and distillate products) with WCSB oil sands crude oil using the weighted-average estimate for the mix of WCSB oil sands crudes likely to be transported in the proposed Project. The incremental GHG emissions were calculated by subtracting from the WTW GHG emissions an equivalent displaced volume of each reference crude. As previously noted, these estimates provide an example of the potential effect on the U.S. carbon footprint, on a life-cycle basis, resulting from displacement of reference crude oils in PADD III refineries; on a global scale, emissions are not likely to change.

TABLE 3.14.3-12
Incremental Annual GHG Emissions of Displacing 100,000 Barrels Per Day of Each Reference Crude with WCSB Oil Sands ($MMTCO_2$-e)

Study	U.S. Average (2005)	Middle Eastern Sour	Mexican Maya	Venezuelan
NETL, 2009	2.4	2.7	1.9	2.6
Jacobs, 2009	2.6	1.5	0.9	0.9
TIAX, 2009	2.1	2.2	1.8	0.4

Note: Venezuelan conventional crude values for NETL refer to a medium crude, not the heavy crude Venezuelan Bachaquero.

As noted elsewhere in the EIS, the near-term initial throughput of the proposed Project is projected to be 700,000 barrels of crude per day with a potential capacity of 830,000 barrels per day.[23] To the extent that

[22] Of *in situ* WCSB oil sands production from SAGD and CSS facilities, CSS accounts for 47 percent of production, and SAGD accounts for 53 percent. This ratio was used to calculate an average for *in situ*-produced dilbit for TIAX, which provided separate estimates for CSS and SAGD dilbit. Primary *in situ* production of WCSB bitumen (i.e., using conventional oil production techniques) was not included since estimates were not provided in the studies included in the scope of this assessment. Primary production currently accounts for 32.9 thousand cubic meters per day, or 14 percent of total oil sands production (ERCB 2010).

[23] We assumed the pipeline would be operating 365 days a year at an *initial* capacity of 700 thousand barrels per day, yielding 560 thousand barrels per day of gasoline and distillate fuels, or 204.4 million barrels of gasoline and

Middle Eastern Sour is the world balancing crude, as indicated in EnSys (2010), it may ultimately be the crude that is backed out of the world market by WCSB oil sands crudes. Taking into account the weighted average mix of WCSB oil sands (e.g., SCO versus dilbit) in the near term that would be transported through the proposed Project, the incremental increase in the U.S. carbon footprint on a life-cycle basis relative to Middle Eastern Sour is likely in the range of 10 to 19 million metric tons of CO_2 equivalent ($MMTCO_2$-e) annually at initial pipeline capacity or 12 to 23 $MMTCO_2$-e annually at potential capacity. This incremental increase in GHG emissions from WCSB relative to reference crudes is calculated by multiplying the expected proposed Project throughput of equivalent gasoline and distillate (560,000 barrels per day at initial capacity or 664,000 barrels per day at potential capacity) by the weighted-average WTW GHG intensity of oil sands crudes that could be transported in the pipeline, and subtracting WTW GHG emissions from the equivalent quantity of Middle Eastern Sour crude (taking into account differences in the yield of gasoline plus diesel product for WCSB versus Middle Eastern crudes). The range of incremental GHG emissions is calculated based on the results from NETL 2009, Jacobs 2009, and TIAX 2009. The lower bounds of 10 and 12 $MMTCO_2$-e for the initial and potential capacities, respectively, are calculated from Jacobs (2009) results; the upper bounds of 19 and 23 $MMTCO_2$-e for the initial and potential capacities, respectively, are calculated from NETL (2009).

From another perspective, WCSB oil sands crude oils could be compared to the heavy crude oils currently being processed in PADD III refineries (primarily Venezuelan Bachaquero and Mexican Mayan). The incremental increase in GHG emissions from the initial throughput of 700,000 barrels per day of WCSB in comparison to these crude oils is likely in the range of 3 to 18 $MMTCO_2$-e annually as compared to Venezuelan reference crudes (with the upper end being the NETL value for a medium, rather than heavy, crude) and 6 to 13 MMTCO2-e annually as compared to Mexican Maya. Scaling up the calculation for a scenario using the potential throughput of 830,000 barrels per day of WCSB, the incremental increase in GHG emissions is in the range of 3 to 21 MMTCO2-e annually as compared to Venezuelan reference crudes, and 7 to 16 $MMTCO_2$-e annually as compared to Mexican Maya.

The full range of incremental GHG emissions estimated across the reference crudes and sub-set of studies is 3 to 19 $MMTCO_2$-e annually at the near term initial throughput or 3 to 23 $MMTCO_2$-e annually at the potential throughput. This overall range of 3 to 23 $MMTCO_2$-e is equivalent to annual GHG emissions from the combustion of fuels in approximately 588,000 to 4,510,000 passenger vehicles or the CO_2 emissions from combusting fuels used to provide the energy consumed by approximately 255,000 to 1,950,000 homes for one year.[24]

The differentials presented here are based on life-cycle emission estimates for current or near-term conditions in the world oil market, as can be seen from the reference years used in each report. Over time, however, the GHG emission estimates for fuels derived from both WCSB oil sands crude oils and the reference crude oils are likely to change.

GHG emissions from the production phase for reference crude oils will become more energy-intensive over time due to the need to extract oil from deeper reservoirs by using more energy-intensive secondary and tertiary recovery techniques, such as CO_2 flood. The reference crude oil reservoirs are one to two miles (or more) underground or under the ocean floor. In contrast, the WCSB oil sands deposits are much shallower and can be extracted using either surface mining or near-surface *in situ* methods. Exploration efforts for new deep oil reservoirs will continue as known reservoirs continue to deplete.

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distillate fuels annually. At its *potential* capacity of 830 thousand barrels per day, 242.4 million barrels of gasoline and distillate fuels would be produced annually.

[24] Equivalencies based on EPA's GHG Equivalency calculator available at: http://www.epa.gov/cleanenergy/energy-resources/calculator.html

In contrast, the extent of the WCSB oil sands deposits is well understood and defined. In the future, *in situ* extraction methods are projected to represent a larger share of the overall oil sands production, increasing from about 45 percent of 2009 oil sands production to an estimated 53 percent by 2030 (ERCB 2010). In particular, the share of SAGD *in situ* extraction methods are projected to rise from roughly 15 percent in 2009 to 40 percent of oil sands production in 2030 (CERA 2010). The GHG profile of this more energy-intensive oil sands extraction method may be reduced by new technologies and innovations to reuse steam onsite and/or improve thermal recovery and in response to incentives created by Alberta's climate policy requiring reductions in GHG emissions intensity from large emitters in the province. However, surface mining is projected to remain the dominant extraction method for WCSB crude oils for the next 20 years (CERA 2010). In consideration of these factors, it is likely that GHG intensity for future reference crude oils will be trending upward while the GHG intensity for WCSB oil sands-derived crude oils will be relatively constant to slightly upward. If this is the case, the differential in life-cycle GHG emissions for fuels refined from these crude oils is likely to decrease.

Conclusions

The studies show conclusively that combustion (i.e., tank-to-wheels) phase of the fuel life-cycle dominates the total GHG life-cycle emissions under all scenarios. Overall, it is clear that comparisons of GHG life-cycle emission estimates for fuels derived from different sources are sensitive to the choice of boundaries, consistent application of boundary conditions within studies, and to key input parameters. In particular, the results depend on assumptions regarding the use of petroleum coke at oil sands facilities, and upon the weighted-average mix of WCSB oil sands crude transported to the United States by the proposed Project or some other transboundary pipeline. SAGD and CSS *in situ* production methods are generally more GHG-intensive than mining, and while SCO requires upgrading prior to pipeline transport, bitumen blends such as dilbit and synbit require additional refining emissions and do not produce an equivalent amount of premium fuel products per barrel input.

Despite the differences in study design and input assumptions, it is clear that WCSB crude oils, as would likely be transported through the proposed Project, are on average somewhat more GHG-intensive than the crudes they would displace in the U.S. refineries. Although EnSys (2010) reported that there would be no substantive change in global GHG emissions as a result of construction of the proposed Project, and no substantive change in WCSB crude oil imports into the United States whether the project is implemented or not, the life-cycle GHG emissions associated with transportation fuels produced in U.S. refineries would increase with increased imports of WCSB crude oils.

As discussed more fully in the appendix, the GHG intensity of reference crudes is very likely to increase in the future as more and more of the world crude supply requires extraction by increasingly energy intensive tertiary and enhanced oil recovery techniques. The energy intensity of surface mined Canadian crudes will be relatively constant while higher energy intensive in-situ production may increase somewhat; the proportion of in situ extraction is forecast to increase relative to the less energy-intensive surface mining. Although there is some uncertainty in the trends for both reference crudes and oil sands, on balance it is likely that the gap in GHG intensity will decrease over time.

Climate Change

Over the past 30 years, changes in the U.S. climate have included an increase in average temperature, an increase in the proportion of heavy precipitation events, changes in snow cover, and an increase in sea level (CCSP 2008). Climate change can exacerbate stresses on ecosystems through high temperatures, reduced water availability, and altered frequency of extreme precipitation events and severe storms (CCSP 2008). However, climate change can also ameliorate stresses on ecosystems through warmer springs, longer growing seasons and related increased productivity (CCSP 2008).

Anticipated impacts from climate change in North America applicable to the regions crossed by the proposed Project include:

- Stream temperatures are likely to increase and are likely to have effects on aquatic ecosystems and water quality;
- Proliferation of exotic grasses and increased temperatures are likely to cause in increase in fire frequency in arid lands; and
- Decreased streamflow, increased water removal, and competition from non-native species are likely to negatively affect river ecosystems in arid lands (CCSP 2008).

While there are uncertainties in the future of climate change, the response of ecosystems and the effects of management should allow ecosystem adaptations that would reduce anticipated damages or enhance beneficial responses associated with climate variability and change (CCSP 2008). Throughout development of the proposed Project, efforts to reduce overall Project-related impacts have been incorporated into the proposed Project. The proposed CMR Plan (Appendix B of the draft EIS) includes construction procedures that would apply directly to the reduction of anticipated climate change-related induced impacts described above, including:

- Restoration of riparian habitats at stream crossings (Sections 3.3 and 3.7 of the draft EIS);
- Prevention of the spread and establishment of noxious and invasive weeds (Section 3.5 of the draft EIS);
- Prevention of the spread of aquatic invasive species (Section 3.7 of the draft EIS); and
- Limiting water withdrawal rates to less than 10 percent (or lower depending on permit requirements) of the base flow and returning water used for hydrostatic testing to the same drainage (Sections 3.3 and 3.7 of the draft EIS); and
- Avoid, minimize, and mitigate impacts to wetlands, including depressional wetlands (Section 3.4 of the draft EIS) that may decrease in abundance due to increased evaporation with increased temperature.

The potential impacts of climate change would not be expected to affect the proposed Project. An increase in temperatures may increase wildfires in the proposed Project area. Any increased intensity of storm events could result in additional flooding in some areas near the proposed Project within the Gulf Coast Segment and Houston Lateral, particularly if hurricane activity increases as a result of oceanic temperature conditions. The proposed Project would be designed and constructed to be consistent with applicable federal, state, and local standards, and therefore should be resistant to forces associated with reasonably likely climate conditions during the lifetime of the pipeline system. Other effects of climate change, such as air quality degradation, health effects, reduced snow pack, and disruption to agricultural production, would not likely impact the proposed Project.

3.14.4 Extraterritorial Concerns

While the proposed Project analyzed in this EIS begins at the international boundary where the pipeline would exit Saskatchewan, Canada and enter the United States through Montana, the origination point of the pipeline system would be in Alberta, Canada. Neither NEPA nor DOS regulations (22 CFR 161.12) nor Executive Orders 13337 and 12114 (Environmental Effects Abroad of Major Federal Actions) legally require that this EIS include an analysis of the environment or activities outside of the United States. As a matter of policy, and in response to concerns that the proposed Project would contribute to certain continental scale environmental impacts, DOS has included a summary of information regarding

environmental analyses and regulations related to the Canadian portion of the proposed Keystone XL Project and WCSB oil sands production. This section addresses (1) the Canadian National Energy Board (NEB) environmental analysis of the Keystone XL Project in Canada, (2) the potential influence of the proposed Project on oil sands development in Canada, (3) a summary of environmental impacts of oil sands development in Alberta, and (4) protections for Canadian and U.S. shared Migratory Bird and Threatened and Endangered Species resources.

3.14.4.1 Canadian National Energy Board Environmental Analysis of the Keystone XL Project

The analysis of the environmental effects of the overall proposed Keystone XL Project has been in progress on both sides of the international border under appropriate regulatory authorities, as discussed in Section 1.4 and Appendix R of the draft EIS. In Canada, the Canadian National Energy Board (NEB) conducted that analysis, held public hearings in September 2009, and issued its findings in March 2010.

The NEB identified the nine key issues listed below relative to the proposed Keystone XL Project:

- The need for the proposed facilities;
- The economic feasibility of the proposed facilities;
- The potential commercial impacts of the proposed project;
- The potential environmental and socio-economic effects of the proposed facilities, including those to be considered under the Canadian Environmental Assessment Act (CEA) (presented in Appendix R of the draft EIS);
- The appropriateness of the general route of the pipeline;
- The method of toll and tariff regulation;
- The suitability of the design of the proposed facilities;
- The terms and conditions to be included in any approval the NEB may issue; and
- Potential impacts of the project on aboriginal interests.

Relative to impacts to aboriginal or indigenous peoples, the NEB granted intervener status to the following aboriginal groups in Canada:

- Moosomin First Nation;
- Neekaneet First Nation No. 380;
- Red Pheasant Band No. 108; and
- Sweetgrass First Nation.

In the March 2010 finding, the NEB determined that the proposed Keystone XL Project is required in Canada to meet the present and future public convenience and necessity, provided that the NEB terms and conditions presented in the project certificate are met, including all commitments made by Keystone during the hearing process. Pertinent NEB documents are provided in Appendix R of the draft EIS.

3.14.4.2 Influence of the Proposed Project on Oil Sands Development in Canada

Based on the findings of EnSys (2010), DOS has concluded that even if the proposed action does not proceed, production from the oil sands in Canada would likely continue at a similar rate. As reported by EnSys (2010):

> "Production levels of oil sands crudes would not be affected by whether or not KXL was built. WCSB production would only be impacted (relative to the CAPP 2010 projection used in the study) if there were no further pipeline expansion out of WCSB and within the USA beyond projects currently under construction. Even then, because of existing available line capacity, oil sands production would not begin to be curtailed until after 2020. Versus the base projections, WCSB production would be curtailed by approximately 0.8 mbd by 2030. Since, to occur, such a scenario would have to entail no expansion of (a) pipelines entirely within Canada that could take WCSB crudes from Alberta to the British Columbia coast, (b) existing cross-border lines from WCSB to the U.S., (c) existing internal domestic U.S. pipelines that could take WCSB crudes to market within the U.S. - and to eastern Canada and (d) alternative proven transport modes, namely rail possibly supported by barge, the scenario is considered unlikely."

In addition to the existing transport capacity into the United States, there would likely be market demand to put in place pipeline capacity into the United States similar to that of the proposed Project, including pipeline capacity to PADD III. Also Canadian producers are actively seeking to develop alternative crude oil markets worldwide, including efforts to develop necessary transportation facilities to allow shipment of WCSB crude oil to British Columbia and onward to Asia, or eastward to Atlantic coast ports for marine shipment will continue. Other countries that would likely represent markets for WCSB crude oil are primarily located in Asia; those nations are experiencing increased demand for crude oil and are currently heavily dependent on OPEC for their supplies. In recent years, Chinese investment in WCSB crude oil production has greatly accelerated. Various pipeline projects have been proposed to transport crude oil from Alberta to the Canadian west coast, although they face significant opposition in the regulatory process (see Section 4.1).

3.14.4.3 Environmental Effects of Oil Sands Development in Alberta

Many commenters on the draft EIS expressed concerns about impacts in western Canada related to the extraction of crude oil from oil sand deposits in the provinces of Alberta and Saskatchewan, Canada. Additionally, there has been much controversy over environmental impacts to wildlife, boreal forests, threatened and endangered species, and water resources related to oil sands production. Evaluation of impacts from extraction of crude oil from the oil sands is outside of the scope of analysis legally required under NEPA. Further, it is not expected that the proposed Project would have any impact on the rate of development of extraction in Canada. However, in response to comments and as a policy decision, a summary of general regulatory oversight and environmental impacts in Canada related to oil sands production has been included.

Government regulators of oil sands activities in Canada are working to manage and provide regional standards for air quality, land impact, and water quality and consumption based on a cumulative effects approach. Oil sands environmental regulations are administered by federal and provincial governments including the Ministry of the Environment, the Canadian Environmental Assessment Agency (which administers the Canadian Environmental Assessment Act), the Alberta Department of Environment, and the Alberta Department of Sustainable Resource Development. Oil sands deposits are located primarily in Alberta, but also extend into Saskatchewan. The Canadian Government and the Government of Alberta have a cooperative agreement to minimize regulatory overlap (the Canada-Alberta Agreement for Environmental Assessment Cooperation). Oil Sands development projects undergo an environmental

review under Alberta's Environmental Protection and Enhancement Act (EPEA) and the Water Act, as well as the CEA and the Species at Risk Act (SARA). Other federal and provincial agencies may participate in the review as Responsible Authorities or as Federal Authorities with specialist advice.

In early April 2011, the Government of Alberta announced that it had prepared a draft development plan for the Lower Athabascan oil sands region. The plan would require cancellation of about 10 oil sands leases, set aside nearly 20,000 square kilometers (7,700 square miles) for conservation, and set new environmental standards for the region in an effort to protect sensitive habitat, wildlife, and forest land. The draft plan will be reviewed for 60 days and a final draft of legislation is planned to be submitted to the Cabinet in 90 days (The Globe and Mail 2011).

Bitumen, a heavy oil extract, is recovered from oil sands by either *in situ* (in place) recovery or surface mining. Most (80 percent) bitumen is recovered using in situ techniques which use SAGD to pump steam underground through a horizontal well to liquefy the bitumen, which is recovered by an extraction well. *In situ* recovery is less disturbing to the land surface than surface mining and does not require tailings ponds. Oil sands underlie 140,200 km^2 (54,132 mi^2) in three areas of northeast Alberta of which 602 km^2 (232 mi^2) has been disturbed by surface mining activity. Surface mining requires an open pit, similar to many coal, iron ore, copper and diamond mines. Mined oil sands are then transported to a cleaning facility where they are mixed with hot water to separate the oil from the sand. There were 91 active oil sands projects in Alberta as of June 2010, four of which are mining projects (Government of Alberta 2010).

The human footprint within Alberta's boreal forest natural region includes: 12 percent agriculture, 3 percent forestry, 2 percent energy, and 1 percent transportation infrastructure, leaving 82 percent of the region with no human footprint (Alberta Biodiversity Monitoring Institute 2009). The human footprint within the Alberta-Pacific Forest Industries Forest Management Agreement Area (Al-Pac FMA), a 57,331 km^2 area centered on the Athabasca oil sand deposit, includes: 4 percent forestry, 2 percent energy, and 1 percent transportation infrastructure, leaving 93 percent with no footprint (ABMI 2009). Cumulative impacts from oil sands development include GHG emissions and land surface alteration. Land surface alteration includes mine sites, tailings ponds, well sites, industrial roads, pipelines, power lines, seismic cut lines, and facilities. Biodiversity indicators evaluate ecosystem intactness or the proportion of human disturbance by assessing when common species become rare or disappear and when weedy or invasive species become common. Intactness indices for the Al-Pac FMA indicate:

- Intactness for 12 old-forest birds ranged from 96 to 100 percent with 7 of 12 old-forest birds less abundant than expected;
- Intactness for 11 winter-active mammals ranged from 89 to 100 percent with 3 of 11 winter-active mammals less abundant than expected;
- Percent occurrence of 16 non-native weeds ranged from 2 to 28 percent with non-native weeds detected across 39 percent of the Al-Pac FMA;
- For 4 of 17 species at risk that were evaluated, intactness was 97 or 98 percent, and 3 of the 4 species were less abundant than expected (the monitoring system is not designed to evaluate the other 13 species at risk);
- Intactness for four old-forest habitats ranged from 91 to 95 percent and for all old-forest habitats was 92 percent; and
- Intactness for live trees was 97 percent, for snags (standing deadwood) was 95 percent, and for downed deadwood was 98 percent (AMBI 2009).

The following cumulative statistics related to environmental effects from oil sands development in Alberta are derived from the records of the province of Alberta (Government of Alberta 2010):

- Alberta's oil sands account for about 5 percent of Canada's overall GHG emissions and Canada is responsible for about 2 percent of global emissions;
- Oil sands mining projects have reduced GHG emissions intensity by an average of 39 percent between 1990 and 2008 and are working toward further reductions;
- All existing and approved oil sands project may withdraw no more than 3 percent of the average annual flow of the Athabasca River (2008 usage was 0.7 percent of the long-term average annual flow);
- Water use by oil sands mining operations continues to decrease, despite significant increases in production;
- Many *in situ* projects recycle up to 90 percent of the water used in their operations, and use deep-well saline water as an alternative to freshwater wherever possible;
- Long-term air quality monitoring since 1995 shows improved or no change in CO, ozone, fine particulate matter, and SO_2, and an increasing trend in NO_2;
- Air quality in the oil sands region is rated good 95 percent of the time;
- Tailings (water, fine silts, left-over bitumen, salts and soluble organic compounds) ponds are constructed with groundwater seepage-capture facilities, and are closely monitored;
- Tailings settling ponds are designed and located after environmental review and bird deterrents are used to prevent birds from landing on tailings ponds;
- Currently, processing 1 tonne (1.1 tons) of oil sand produces about 94 liters (25 gallons) of tailings;
- About 602 km^2 (232 mi^2) have been disturbed by oil sands mining activity of which 67 km^2 (26 mi^2) has been or is in the process of reclamation (mine operators must provide a reclamation security bond);
- Alberta's boreal forest covers 381,000 km^2 (147,100 mi^2) of which the maximum area available for oil sands mining is 4,800 km^2 (1,854 mi^2) or about 1.25 percent of Alberta's boreal forest area;
- Alberta has committed to a cumulative effects approach that looks at potential impacts of all projects within a region; and
- The Alberta Land Stewardship Act supports the Land-use Framework, which includes province-wide strategies for establishing monitoring systems, promoting efficient use of lands, reducing impact of human activities and including aboriginal people in land-use planning.

3.14.4.4 Protections for Shared Migratory Bird and Threatened and Endangered Species Resources

Oil sands projects and oil transportation pipelines are evaluated and permitted by Canadian federal and provincial Canadian governments. Canada's version of the U.S. Migratory Bird Treaty Act (MBTA) is called the Migratory Bird Convention Act (MBCA). Both the U.S. and Canadian acts are based on the Migratory Birds Convention treaty signed in 1916 by the U.S. and the United Kingdom (on behalf of Canada). The Canadian Wildlife Service handles wildlife matters that are the responsibility of the Canadian federal government. Canadian regulations supporting the MBCA are available at

http://laws.justice.gc.ca/en/M-7.01/C.R.C.-c.1036/. In addition Canada's rare and endangered migratory birds are protected under the Species at Risk Act (see http://www.sararegistry.gc.ca/the_act/html). Canadian protections for migratory birds are parallel to U.S. migratory bird protections. Canada also provides for protection of migratory bird habitat within government-recognized sanctuaries. Recent losses of migratory birds at WCSB oil sands tailings ponds have been cited as violations of the MBCA and have been prosecuted by the Canadian government.

Bird resources (waterfowl, waterbirds, shorebirds, landbirds) are shared on a continental scale. The Tri-National North American Bird Conservation Initiative Committee was established to increase cooperation and effectiveness of bird conservation efforts among Canada, the United States, and Mexico. Partnership-based bird conservation initiatives have produced national and international conservation plans for birds that include species status assessments, population goals, habitat conservation threats, issues and objectives, and monitoring needs. Multi-National North American bird conservation plans include the North American Waterfowl Management Plan, North American Landbird Conservation Plan, United States and Canadian Shorebird Conservation Plans, Waterbird Conservation for the Americas, North American Grouse Management Strategy, and Northern Bobwhite Conservation Initiative.

The Partners in Flight conservation assessment concluded that nearly half of native landbirds in Canada, Mexico, and the U.S. depend on habitats in at least two of the countries and more than 200 species (more than 80 percent of all individual landbirds) use habitats in all three countries in at least one season (Berlanga et al. 2010). The landbird assessment identified 148 bird species in need of immediate conservation attention because of highly threatened and declining populations. The most imperiled species include: 44 species with very limited distribution, mostly in Mexico, that are at greatest risk of extinction; 80 tropical residents dependent on deciduous, highland and evergreen forests in Mexico; and 24 species that breed in temperate-zone forests, grasslands, and aridland habitats (Berlanga et al. 2010). Steep declines in 42 common bird species have occurred over the past 40 years with the majority of steeply declining species breeding in the northern United States and southern Canada, and wintering in the southern United States and Mexico (Berlanga et al. 2010). Declining bird populations face a diversity of threats on breeding grounds from land-use policies and practices related to agriculture, livestock grazing, urbanization, energy development, and logging (Berlanga et al. 2010). Migratory species are threatened on their wintering grounds by loss of grasslands in northern Mexico and tropical forests in southern Mexico (Berlanga et al. 2010).

Neither Section 7 of the ESA nor the Section 7 consultation and analysis process under ESA implementing regulations address species outside the borders of the U.S. and nothing in the language of Section 7 indicate that it would apply extraterritorially. Shared species currently covered by both the ESA and the Canadian SARA that could potentially occur within the U.S. and Canadian portions of the proposed Keystone XL Project are listed in Table 3.14.4-1.

Conservation measures developed to reduce impacts to these species for the proposed Project are described in Section 3.8 and Appendix T of the draft EIS. [25] Two U.S. candidate species occurring in Montana and South Dakota are not yet eligible for protection under the ESA but are protected under Canada's SARA (Table 3.14.4-1); and the swift fox is listed as threatened in Canada. Required mitigation, including seasonal restrictions, to minimize impacts of the proposed Keystone XL Project to SARA-protected species is available in Appendix R of the draft EIS.

[25] The final EIS will include an updated Biological Assessment.

TABLE 3.14.4-1 Endangered Species Act (U.S.) and Species at Risk Act (Canada) Species That Occur in Both the U.S. and Canadian Regions of the Proposed Keystone XL Project				
Common Name	**Scientific Name**	**Status U.S./Status Canada**	**Preliminary Findings (U.S.)**	**Evaluation (Canada)**
Mountain Plover	*Charadrius montanus*	Proposed / Endangered	NLAA	NS
Piping Plover	*Charadrius melodus*	Threatened / Endangered	NLAA	NS
Whooping Crane	*Grus americana*	Endangered / Endangered	NLAA	Not Evaluated
Greater Sage Grouse	*Centrocercus urophasianus*	Candidate / Endangered	NA	NS
Sprague's Pipit	*Antus spragueii*	Candidate / Threatened	NA	NS

NLAA = may affect, not likely to adversely affect species
NA = not applicable
NS = effects not significant

3.14.5 Summary of Cumulative Impacts

There have been no substantive changes to this section and therefore it is not included in the SDEIS. The draft EIS subsection can be downloaded at www.keystonepipeline-xl.state.gov.

3.14.6 References

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CAPP. See Canadian Association of Petroleum Producers.

CCSP. See U.S. Climate Change Science Program.

CEQ. See Council on Environmental Quality.

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[FIGURE PLACEHOLDER]

3.14.3-1 Comparison of the Percent Differential for WTW GHGs from Gasoline Produced from Canadian Oil Sands Relative to Reference Crudes

3.14.3-2 Comparison of the Percent Differential for WTT GHGs from Gasoline Produced from Canadian Oil Sands Relative to Reference Crudes

3.14.3-3 Percent Change in WTW Weighted-Average GHG Emissions from WCSB Oil Sands Crudes Relative to Reference Crudes

3.15 POTENTIAL IMPACTS OF THE BAKKEN MARKETLINK AND CUSHING MARKETLINK PROJECTS

This section of the EIS provides summary information on the potential impacts of the proposed Marketlink projects based on the limited information available on the design, construction, and operation of these projects. Keystone Marketlink LLC may be required to obtain permits to construct and operate the planned Marketlink projects, and if permits are required, permit applications for these projects would be reviewed and acted on by agencies other than DOS. Those reviews would address potential impacts in greater detail and would identify any appropriate mitigation measures that would avoid or minimize impacts.

As noted in Figure 2.5.3-2, the tank farm for the Bakken Marketlink Project near Baker, Montana would be adjacent to proposed Project Pump Station 14 and the northeastern and northwestern property boundaries would extend along the borders of the ROWs for the proposed Project and the existing Bridger Pipeline. The site of the tank farm and Pump Station 14 would have an area of approximately 15 acres and the offsite metering manifold would have an area of approximately 9 acres. The location of the offsite metering manifold has not been identified but would likely be in close proximity to the tank farm site. There would also be a 16-inch-diameter pipeline about 5 miles long that would extend from an existing crude oil tank farm to the Bakken Marketlink facilities. The route of that pipeline has not been determined.

Keystone reported that the property is currently used as pastureland and hayfields and that a survey of the property indicated that there were no cultural resources, listed species or listed species habitat, raptors, or wetlands on the property. A review of aerial photographs confirmed the current use of the land and that there are no waterbodies associated with the site. A site inspection by the DOS third-party contractor confirmed these findings. As a result, the potential impacts associated with expansion of the pump station site to include the tank farm would likely be similar to those described in Section 3.0 for the proposed Project pump station and pipeline ROW in that area.

The proposed facilities near Baker would not likely affect the piping plover since this region is used only during migration, nor would they likely affect the whooping crane since this region is not within the primary migration corridor. The proposed Bakken Marketlink facilities near Baker would be within a region used by greater sage grouse, including previously identified lek locations, and Sprague's pipit and in a region historically used by mountain plover. Potential impacts of the proposed Bakken Marketlink facilities on sage grouse, interior least tern, and mountain plover, and potential impacts to habitats that they depend on, would be evaluated during environmental reviews conducted during permitting for the proposed Bakken Marketlink Project, if permits are required for the project. The potential impacts would be evaluated in coordination with MDEQ, Montana Fish, Wildlife & Parks, and the U.S. Fish and Wildlife Service. Impacts would be avoided, minimized, or mitigated in accordance with the requirements of those agencies.

The tanks associated with the proposed Bakken Marketlink facilities near Baker would have emissions similar to or less than those of the Cushing tank farm listed in Table 3.12.1-4 of draft EIS. The tank sizes and likely throughput of the connected actions would be less than the tank sizes and throughput expected for the proposed Project at the Cushing tank farm. However, the design specifics of the tanks and the anticipated throughputs were not available at the time that this SDEIS was prepared. Keystone Marketlink LLC would be required to provide those data along with project-specific emission estimates in its application for an air permit for the project.

The facilities for both of the Marketlink projects at Cushing would be installed within the boundaries of the proposed Cushing tank farm, which would house Pump Station 32 of the proposed Project. As a result, the potential impacts of construction of those facilities would be similar to those described for the Cushing tank farm in Sections 3.1 through 3.12. The tanks associated with the proposed Marketlink project at Cushing would have emissions similar to or less than those of the Cushing tank farm listed in Table 3.12.1-4 of the draft EIS. The tank sizes and likely throughputs of these connected actions would be less than the tank sizes and throughput expected for the proposed Project at the Cushing tank farm. The design specifics of the tanks and the anticipated throughputs for the two Marketlink facilities at Cushing were not available at the time that this SDEIS was prepared. Keystone Marketlink LLC would be required to provide those data along with project-specific emission estimates in its applications for air permits for the projects. Emissions from the projects would be required to be in compliance with the emission limits of the permits issued.

The addition of the Bakken Marketlink transport capacity would not be expected to impact the rate of growth in crude oil production from the Bakken formation in the Williston basin in North Dakota and Montana. A North Dakota Pipeline Authority report (2010) examined projected increases in production in North Dakota and eastern Montana compared to current and planned transportation routes for crude oil. That forecast indicates that even under high growth projections for crude oil production in the area, there is sufficient existing and planned pipeline transport capacity to accommodate the increased production through at least 2017 without the Bakken Marketlink project. For the lower growth projections, the report indicates that there is a potential excess crude oil transport capacity out of the region of approximately 160,000 bpd.

3.15.1 References

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4.0 ALTERNATIVES

DOS has included the entire revised Alternatives section in this SDEIS to provide reviewers with an expanded description of the screening method used in the alternatives analysis, supplemental information on the No Action Alternative, additional System Alternatives and expanded analysis of some system alternatives, and additional route alternatives, including route alternatives identified in response to concerns expressed in comments received on the draft EIS related to the Sand Hills topographic region and the NHPAQ system, which includes the Ogallala aquifer in Nebraska. There are also two new subsections: Pipeline Design Alternatives (Section 4.4) and Alternative Sites for Aboveground Facilities (Section 4.5). Figures are presented at the end of this section.

Consistent with NEPA, DOS and the cooperating agencies conducted an analysis of alternatives to the proposed Project. The alternatives were developed based on the purpose and need for the proposed Project as discussed in Section 1.2. The alternatives analysis relied on information provided to agencies in the presidential permit and MFSA applications (including supplemental submittals), information and suggestions provided during scoping for the EIS and during the public comment period on the draft EIS, and information obtained through research and analyses conducted by DOS and its third-party contractor.

The alternatives analysis included a screening process that first considered a range of categories of potential alternatives. The categories of alternatives considered included:

- No Action Alternative (Section 4.1) − addresses projected beneficial and adverse environmental, social, and economic impacts that would result if the proposed Project were not implemented;
- System Alternatives (Section 4.2) − the use of other pipeline systems or other methods of providing heavy crude oil to the Cushing tank farm (PADD II) and the U.S. Gulf Coast market (PADD III);
- Major Route Alternatives and Route Variations (Section 4.3) − other potential pipeline routes for transporting heavy crude oil from the U.S./Canada border to the Cushing Tank Farm (PADD II) and the U.S. Gulf Coast Market (PADD III), and minor route adjustments along the proposed Project route;
- Alternative Pipeline Designs (Section 4.4) − aboveground installation of the pipeline and alternate pipeline diameters; and
- Alternative Sites for Aboveground Facilities (Section 4.5) − alternative sites for pump stations, MLVs, and the tank farm.

The alternatives analysis presented in the draft EIS was revised based on comments on the draft EIS and updated information or information unavailable at the time the draft EIS was issued. This information includes the recent EnSys Energy and Systems, Inc. report (EnSys 2010) on the need for the proposed Project and the relationship of the proposed Project to production of crude oil from the Canadian oil sands. DOE contracted EnSys to evaluate different WSCB crude oil transportation scenarios through 2030. DOE contracted the study to assist DOS in better understanding the potential impacts of the presence or absence of the proposed Project on U.S. refining and petroleum imports, international markets, and production of crude oil from the WCSB. The EnSys (2010) report is presented Appendix A of this SDEIS.

The conclusions reached in the revised assessment of alternatives remain the same as those presented in the draft EIS.

4.1 NO ACTION ALTERNATIVE

Under the No Action Alternative, the proposed Project would not be constructed and operated. Therefore, selection of the No Action Alternative would not require the issuance of a Presidential Permit for construction and operation of the proposed Project. Under the No Action Alternative, the environmental effects specific to the proposed Project described in this EIS would not occur. As described below, if the No Action Alternative is implemented it is likely that the other methods of transporting WCSB crude oil to the world marketplace would be implemented. Impact comparison scenarios in the U.S. associated with the No Action Alternative are presented in Table 4.1-1.

TABLE 4.1-1
Comparison of Key Impacts of the Proposed Project and the No Action Alternative

Resource	Summary of the Key Impacts of Proposed Project [a]	Impact Comparison for Scenarios Associated with the No Action Alternative [c]		
		No New or Expanded Pipelines in Canada or the U.S. [b]	New Pipeline Between PADDs II and III	New Pipeline from Canada/U.S. Border to PADD III
Geology	• Fossil damage or destruction and unauthorized collection	No impact to Geology	Less than or equal to	Greater than or equal to
Soils and Sediments	• Temporary to short-term soil erosion • Minor loss of topsoil • Short-term to long-term soil compaction	No impact to Soils and Sediments	Less than or equal to	Greater than or equal to
Water Resources	• Temporary to short-term surface water quality degradation and disturbance of areas with high water tables • Temporary to short-term increase in surface water runoff in the ROW • Temporary to short-term degradation of aquatic habitat • Changes in channel morphology and stability • Temporary to long-term decrease in bank stability • Temporary reduced flow in streams during hydrostatic testing	No impact to Water Resources	Less than or equal to	Greater than or equal to
Wetlands	• Loss of wetlands and modification to productivity • Temporary to permanent change of wetland vegetation community, including forested wetlands. • Wetland soil disturbance • Temporary increase in turbidity and changes in wetland hydrology and water quality	No impact to Wetlands		

TABLE 4.1-1
Comparison of Key Impacts of the Proposed Project and the No Action Alternative

Resource	Summary of the Key Impacts of Proposed Project [a]	Impact Comparison for Scenarios Associated with the No Action Alternative [c]		
		No New or Expanded Pipelines in Canada or the U.S. [b]	New Pipeline Between PADDs II and III	New Pipeline from Canada/U.S. Border to PADD III
	• Permanent alteration in water-holding capacity due to alteration or breaching of water-retaining substrates in the Prairie Pothole and Rainwater Basin regions • Minor long-term alteration in vegetation productivity and life stage timing due to increased soil temperatures • Minor and long-term alteration in freeze-thaw timing due to increased water temperatures.			
Vegetation	• Temporary to permanent modification of vegetation community composition and structure, including croplands, grassland/ rangeland, sagebrush, and riparian and upland forests, and CRP and WRP land. • Potential expansion of invasive and noxious weed populations along the pipeline ROW • Minor short- to long-term soil and sod disturbance potentially altering hydrologic patterns, inhibiting water infiltration and seed germination, or increasing siltation • Alteration in vegetation productivity and life stage timing due to increased soil temperatures	No impact to Vegetation	Less than or equal to	Greater than or equal to
Wildlife	• Short-term disturbance and medium to long-term loss or modification of habitats, including fragmentation, that provide forage, cover, and breeding	No impact to Wildlife	Less than or equal to	Greater than or equal to

TABLE 4.1-1
Comparison of Key Impacts of the Proposed Project and the No Action Alternative

Resource	Summary of the Key Impacts of Proposed Project [a]	Impact Comparison for Scenarios Associated with the No Action Alternative [c]		
		No New or Expanded Pipelines in Canada or the U.S. [b]	New Pipeline Between PADDs II and III	New Pipeline from Canada/U.S. Border to PADD III
	habitat for wildlife. • Direct mortality during construction and maintenance • Indirect mortality and reduced breeding success due to stress or avoidance of feeding during construction and from noise and human activity during operation • Reduced survival or reproduction due to decreased abundance of forage species or reduced cover			
Fisheries Resources	• Habitat loss, alteration, and fragmentation, including habitats for recreationally and commercially important species • Short- to long-term changes in benthic invertebrate community • Increased water temperature due to removal of vegetation • Direct mortality to fishery and aquatic resources during construction • Gill irritation, avoidance behaviors, and stress due to increase in suspended sediments potentially leading to mortality or reduced productivity • Minor reduction of population growth through burial of eggs or young fish by sediments • Temporary blockage or delays to normal fish movements • Entrainment of eggs, small fish, and	No impact to Fisheries Resources	Less than or equal to	Greater than or equal to

TABLE 4.1-1
Comparison of Key Impacts of the Proposed Project and the No Action Alternative

Resource	Summary of the Key Impacts of Proposed Project [a]	Impact Comparison for Scenarios Associated with the No Action Alternative [c]		
		No New or Expanded Pipelines in Canada or the U.S. [b]	New Pipeline Between PADDs II and III	New Pipeline from Canada/U.S. Border to PADD III
	drifting macroinvertebrates during withdrawal of hydrostatic test water			
Threatened and Endangered (T&E) Species	• May affect, but not likely to adversely affect 11 species. American burying beetle potentially adversely affected. • Loss, alteration, and fragmentation of habitat supporting T&E species • Stress to T&E species, reduced breeding success, and avoidance of feeding due to noise and increased human activity • Reduced survival or reproduction due to decreased abundance of forage species or reduced cover	No impact to T&E Species	NA[d] T&E	NA[d] T&E
Land Use, Recreation, and Visual Resources	• Short- to long-term loss of agricultural productivity and crop loss • Some current land uses would be converted to permanent utility use • Temporary visual impacts due to construction, and short- to permanent visual impacts from changes in vegetation composition and structure and the presence of aboveground facilities. • Temporary impacts to recreation from increases in noise, dust, and construction activity and traffic.	No impact to Land Use, Recreation, and Visual Resources	Less than or equal to	Greater than or equal to
Socioeconomics	• Compensation to property owners for ROW easements • Economic benefits from the purchase of goods and services during construction and operation		Less than or equal to	

TABLE 4.1-1
Comparison of Key Impacts of the Proposed Project and the No Action Alternative

Resource	Summary of the Key Impacts of Proposed Project [a]	Impact Comparison for Scenarios Associated with the No Action Alternative [c]		
		No New or Expanded Pipelines in Canada or the U.S. [b]	New Pipeline Between PADDs II and III	New Pipeline from Canada/U.S. Border to PADD III
	• Minor, temporary adverse impacts on services associated with the needs of construction workers • Positive fiscal impacts associated with property, sales, and other tax revenues • Positive impact to employment opportunities and income levels • Minor, temporary impact on transient housing • Potential changes in property values			
Air Quality and Noise	• Release of fugitive dust • Emissions from fossil-fuel fired construction equipment and vehicles • Emissions from open burning • Emission of volatile organic compounds and hazardous air pollutants from temporary fuel transfer systems and storage tanks, surge relief tanks, and crude oil storage tanks • Minimal fugitive emissions from pipeline connections and pumping equipment at the pump stations. • Minor, short-term, localized, and intermittent impacts from construction noise • Minor noise impacts from operation of the electrically-powered pump stations	No impact to Air Quality and Noise	Less than or equal to	Greater than or equal to
Greenhouse Gas (GHG) Emissions	• Minor emissions of GHG from construction and operation	Greater than	Less than or equal to	Greater than or equal to

[a] Definitions of duration of impacts:

Temporary impacts generally occur during construction, with resources returning to pre-construction conditions almost immediately afterward.

Short-term impacts last up to approximately 3 years after completion of construction.

Long term impacts result when resources require more than 3 years to recover.

Permanent impacts occur when resources do not return to preconstruction conditions during the life of the proposed Project (e.g., impacts to vegetation due to construction of aboveground structures).

[b] This alternative assumes that refineries in PADD III would continue to receive crude oil from foreign sources, with the decreasing supply from Mexico and Venezuela to be replaced by crude oil from more distant countries requiring longer shipping routes. EnSys (2010) reported that it is unlikely that there would be no expansion of existing pipelines or installation of new pipelines in both Canada and the U.S. to transport WCSB crude oil from Canada to world markets.

[c] For most resources, the type, magnitude, and duration of impacts to the resource areas for the scenarios listed would be similar to those of the proposed Project. Therefore, the table indicates the comparison to the suite of impacts listed for the proposed Project for each resource. Greater than, equal to, less than = the impacts of the No Action Alternative for the listed scenario are greater than, equal to, or less than those of the proposed Project.

[d] NA = not applicable.

4.1.1 PADD III Crude Oil Demand and Supply with the No Action Alternative

EnSys (2010) reported that in 2009, PADD III refineries imported 5.1 million bpd of crude oil, including 2.9 million bpd of heavy crude oil, obtained from more than 40 countries. The top 4 suppliers were Mexico (21 percent), Venezuela (17 percent), Saudi Arabia (12 percent), and Nigeria (11 percent) (EIA 2010b). PADD III refinery runs are projected to grow by over 500,000 bpd by 2020 (Purvin & Gertz 2009); however, Mexico and Nigeria face declining or uncertain production horizons and Venezuelan supplies are subject to both decreasing reserves and political uncertainty. As a result, the PADD III demand for substitute sources of crude oil, particularly the heavy crude oil currently sourced from Mexico and Venezuela, is expected to increase in the future (Sections 1.2 and 1.4) under the EIA (2010) reference case projections, that incorporate reasonably foreseeable energy projects, energy conservation efforts, and renewable energy resource development. Although some analysts project that in the short-term the worldwide crude oil slate could become somewhat lighter due to short-term increases in natural gas liquids and condensate supply, PADD III refiners may find a more competitive world market for heavy crude because there has been a worldwide trend in developing capacity to refine heavier grades of crude, including in countries that produce such heavier grades (e.g., Brazil, Saudi Arabia, Qatar, and Kuwait) (EnSys 2010). As a result, EnSys (2010) stated the following:

> "Taken together, these developments create an outlook where PADD III refiners could have difficulty in the future competing for and obtaining sufficient heavy crudes to fill available heavy crude processing and upgrading capacity, and therefore *a priori* could be expected to have an interest in acquiring heavy WCSB crudes."

Under the No Action Alternative, the PADD III refineries would continue to acquire heavy crude oil primarily from sources other than Canada to fulfill PADD III heavy crude oil demand and/or find alternative methods to deliver WCSB heavy crude oil to PADD III. Under the No Action Alternative, crude oil demand in PADD III would likely be met by one or more of the following options:

- Delivery by marine tankers from countries outside of North America (primarily from the Middle East);
- Delivery from the WCSB through the construction of alternative pipeline systems between the WCSB and PADD III;
- Delivery from the WCSB to PADD III via existing pipeline connections to PADD II and new onward pipeline connections to PADD III;
- Delivery of WCSB crude by other transportation methods (e.g., railroad tank cars, perhaps supported by barge transport); or
- Delivery from the WCSB through the construction of a pipeline to a port in Canada and subsequent shipment of the oil by marine tanker to PADD III.

The No Action Alternative would not provide PADD III with a stable, overland transportation system for access to a secure source of North American crude oil in the near term. As a result, in the near term PADD III would continue to be dependent on less reliable foreign oil supplies that require greater marine shipping distances and, thus, involve longer delays in finding substitute sources to respond to supply disruptions that may occur.

While at least in the short term projections are that world crude oil supplies may become somewhat lighter (EnSys 2010), the longer term trend towards exploitation of heavier crude oil resources and the geographically close supplies of heavy crude from Mexico and Venezuela has led to increased reliance on heavy crude oil at PADD III refineries. PADD III refineries already have substantial capacity at their

existing facilities to allow the refinement of heavy crude oil (Gunaseelan and Buehler 2009, Sword 2008). In addition, major refinery upgrades representing a total of 365,000 bpd of new capacity are planned at Port Arthur, Texas refineries that would have direct pipeline access to oil transported through the proposed Project, and several PADD III refineries without direct pipeline access have either implemented or are planning upgrades to increase heavy oil refining capacity (e.g., Artesia, New Mexico, Garyville, Louisiana, Borger, Texas) (CAPP 2009 2010). Additionally, CAPP 2010 reports that plans for refinery upgrades to handle heavy crude oil have been revived in St. Charles, Louisiana and Tuscaloosa, Alabama.

Under the No Action Alternative, excess pipeline capacity into the northern U.S. from Canada, primarily into PADD II, would likely persist until at least 2020 (EnSys 2010), although the supply of WCSB crude oil to PADD III refineries would be constrained by existing pipeline capacity into PADD III (CAPP 2009, Purvin & Gertz 2009) unless an alternative pipeline from PADD II to PADD III were constructed. PADD III represents the largest refining capacity in the U.S. and therefore would continue to acquire heavy crude oil primarily from sources other than Canada to fulfill demand in the near term. The refineries receive WCSB heavy crude oil from the 96,000-bpd ExxonMobil Pegasus Pipeline, which is the only pipeline that provides PADD III refineries direct access to WCSB crude oil (CAPP 2009). Small volumes of WCSB heavy crude oil currently move to Gulf Coast refineries by barge from PADD II and by marine tanker from the Westridge dock near Vancouver, British Columbia, Canada (EnSys 2010).

If the constraints on delivery of WCSB crude oil into PADD III persisted, there would tend to be upward pressure on the price of heavy crude oil imported into PADD III and on the prices of refined products shipped out of PADD III, although the impact of this upward pressure is projected to be small over the longer term (EnSys 2010). If long-term constraints on delivery of WCSB crude oil to the U.S. Gulf Coast and the Canadian west coast persist, a glut of WCSB crude oil could develop in PADD II potentially leading to downward pressure on the price of crude oil in PADD II sometime after 2020 (EnSys 2010). Currently, the lack of transport capacity out of Cushing has substantially depressed the price of West Texas Intermediate (WTI) crude compared to other world benchmark crudes, such as Brent Blend. It is not yet clear if this is a short-term phenomenon, or whether or how the phenomenon might be reflected in refined fuel prices in the PADD II area.

Under the No Action Alternative, in the immediate future, the gap created by declining supply from traditional heavy crude suppliers, primarily Mexico and Venezuela, would likely be filled by increases in other foreign imports delivered by marine tanker, notably from the Middle East (EnSys 2010). Increased reliance on Middle East supply would lead to increased marine tanker traffic to PADD III and higher priced Middle Eastern medium crudes may not fit the crude slates of upgraded PADD III refineries that are better optimized to process heavy crude oil. In the medium- to long-term, a crude oil pipeline system from Canada to PADD III (other than the proposed Project) could be constructed to provide WCSB crude oil to PADD III refineries, and the EnSys (2010) report results indicate that there is a strong market preference to put in place a broadly similar capacity to that provided by the proposed Project. Alternatively, additional pipeline infrastructure could be constructed to provide greater pipeline capacity between PADD II and PADD III that, in conjunction with existing excess cross border pipeline capacity in PADD II, could meet short term heavy crude oil demand in PADD III (until approximately 2020).

4.1.2 WCSB Crude Oil Production and World Market Access under the No Action Alternative

4.1.2.1 WCSB Crude Oil Production and Existing Export Capacity

Currently, crude oil production from the WCSB totals approximately 2.4 million bpd, with approximately 55 percent coming from the oil sands (CAPP 2010). Forecasts by CAPP project growth in WCSB production to 4.19 million bpd by 2025, with the oil sands comprising 3.5 million bpd. These growth

projections are based upon a survey of projects operating, projects under construction, and projects announced for construction. There are numerous logistical challenges to reaching such production numbers, including limited labor supply and long supply chains to get materials to northern Alberta, but other production outlooks, such as IEO (2010), have similar production amounts from the oil sands for 2025 time period. The other forecasts that include similar numbers for potential oil-sands sands production, show a rough correlation between world crude oil price and oil-sands production – higher world oil prices lead to higher production from the oil sands, lower world oil prices lead to lower production from the oil sands (IEO 2010, IEA 2010).

Currently, there is approximately 3.8 million bpd of existing pipeline capacity to transport crude oil produced in the WCSB into the United States. Comparing the projected production to existing capacity, EnSys (2010) stated that:

> "Under every scenario where pipeline expansion is not restricted, WCSB crude supply is projected to be maintained at the levels projected in 2010 by the Canadian Association of Petroleum Producers . . . [and] . . . current pipeline capacity would be sufficient to deliver projected WCSB production to market at least until 2020 even with no expansion."

Examining the existing cross-border pipeline capacity does not give the entire picture, because, as described in the previous section, there is market demand in PADD III for WCSB crudes, and the existing cross-border pipeline capacity does not deliver to PADD III. That market demand in PADD III is not dependent upon construction of the proposed Project, since market demand would exist to put in place similar capacity to deliver WCSB crudes to PADD III (EnSys 2010).

The United States is currently the only substantial export market for WCSB crudes, as there is limited transport capacity to move the crudes to the world market. However, there is interest on the part of crude oil producers to gain access to other markets.

4.1.2.2 WCSB Crude Oil Potential Access to World Markets

Producers in Canada have stated that if the U.S. market is not available to them, much of the WCSB crude oil would be shipped outside of North America, particularly to Asian markets including Japan, China, South Korea, and India, which are the world's third through sixth largest importers of oil, respectively (CIA 2010).

Under the No Action Alternative, it is likely that there would be an increase in market incentives for WCSB crude oil producers to seek access to Asian markets until sufficient alternative infrastructure becomes available to facilitate access to the U.S. PADD III market. According to EnSys (2010):

> "Over the next twenty years, the principal choice for WCSB exporters is between moving increasing crude oil volumes to the USA or to Asia. Led by China, which has already bought heavily into oil sands production, Asia constitutes the major region for future petroleum product demand and refining capacity growth and offers Canada diversification of markets. In addition, costs for transporting WCSB crudes to major markets in northeast Asia (China, Japan, South Korea, Taiwan) are lower than to transport the same crudes via pipeline to the US Gulf Coast. Projections from this study, which are supported by third party information, indicate that Asian markets are attractive and could absorb at least 1 mbd [million barrels per day] of WCSB crudes, potentially significantly more; this versus the less than 50,000 bpd of WCSB crude that moves to Asia today."

If large quantities of WCSB crude oil were to be shipped to Asia, the oil would likely move by pipeline to marine ports in Canada and would be transported from there by marine tanker to countries outside of North America. Within Canada, this would require construction of at least one new pipeline from the WCSB production area to a port on the Canadian west coast. It is likely that an existing port would have to be modified or a new port would have to be constructed in order to handle very large volumes of oil exports. Examples of potential world market access pathways based on currently available information are described below.

Northern Gateway Pipeline

In May 2010 Enbridge submitted an application to the NEB seeking approval for construction and operation of the Northern Gateway Pipeline. According to the application, this facility would initially transport up to 525,000 bpd of WCSB crude oil from Edmonton to a port in Kitimat, B.C. The ultimate destination of the crude oil transported by this project would be the Asia-Pacific Rim countries, particularly China and Korea, and to refineries on the U.S. West Coast. The project could be expanded to transport up to 800,000 bpd and would include a diluent pipeline that would transport 193,000 bpd of diluent from a port at Kitimat to the Edmonton area. The proposed route is depicted on Figure 4.1.2-1. The current target for startup is 2016, although the project is encountering strong resistance from First Nations and environmental groups that may delay or postpone the project.

Sinopec Corporation, the second-largest oil producer and largest refiner in China, announced that it is among a group of producers and refiners providing $100 million (Canadian $) to assist in financing the $5.5 billion (Canadian $) Northern Gateway pipeline project (Reuters 2011a). The financing is intended to be used for regulatory and development costs in exchange for guaranteed space on the pipeline and the right to an equity stake.

Kinder Morgan Trans Mountain Pipeline Projects

The existing Kinder Morgan Trans Mountain Pipeline transports WCSB crudes west from Edmonton to the 55,000 bpd Chevron refinery at Burnaby and to a dock at Westridge, both near Vancouver, B.C. The Trans Mountain pipeline also connects to the Puget Sound Pipeline, a spur that extends to four refineries at Ferndale, Anacortes, and Cherry Point in Washington. Crude oil can be shipped via the Westridge or Burnaby docks by barge or tanker to U.S. refineries in Washington, although historically this mode of transport has been primarily to California, the U.S. Gulf Coast, and Asia. Kinder Morgan expanded the Trans Mountain system to a maximum capacity of 300,000 bpd in 2008 via its TMX1 project. However even with that expansion, the system is over subscribed as reported by EnSys (2010):

> "According to a press announcement in late October 2010 [Reuters 2010], the Transmountain pipeline is running at 316,000 bpd, i.e. above nameplate capacity, and is 32% over-subscribed for the month of November as of the time of this report. This tends to reinforce that there is growing demand for the line's capacity."

That situation extended into early 2011, when Kinder Morgan informed shippers that they would only be able to ship approximately 75 percent of the volumes requested (Reuters 2011b).

Kinder Morgan has plans to further expand this pipeline system with its TMX2 looping project that would increase the capacity to 380,000 bpd, and further increase the capacity 700,000 bpd with its TMX3 project. However, as of the time this EIS was prepared, Kinder Morgan had not announced a decision to go forward with either project, and in January 2011, Petroleum News (2011) reported that "Kinder Morgan decided last year to slow plans to further increase Trans Mountain capacity." The routes of the existing Trans Mountain pipelines system and the planned expansions are depicted on Figure 4.1.2-1.

Based on existing information, it is assumed that the expansions would be implemented in the 2015 to 2020 time frame. Kinder Morgan also plans to upgrade the Westridge dock to allow use of larger tankers, although this proposed project faces strong opposition (as does the looping project that would expand capacity of the existing pipeline). In late November 2010, Kinder Morgan applied to the NEB to establish longer term "firm service" contracts for WCSB crude oil shipments across the Westridge Dock (EnSys 2010).

Kinder Morgan has also announced plans for a Northern Leg expansion of the Trans Mountain system. The Northern Leg would extend from Edmonton to near Valemont, B.C., then extend west to Kitimat (see Figure 4.1.2-1). As currently planned, the maximum capacity of the Northern Leg would be 400,000 bpd, and the port at Kitimat can accommodate very large crude carrier class tank ships. The Northern Leg expansion is considered by Kinder Morgan to be a longer-term project. It also faces strong opposition from First Nations and environmental groups. If regulatory approvals were obtained and all of the above expansions are constructed and operated, the Trans Mountain system would have a total capacity of 1.1 million bpd.

Other Potential Projects

There are several other potential projects announced previously that could transport WCSB crude oil that are presently dormant and may be revived in the future. These projects are considered potential System Alternatives and are described in Section 4.2.

4.1.2.3 Likely Future Impacts under the No Action Alternative

Any alternative pipeline system constructed to move WCSB crude oil directly to PADD III refineries would likely have environmental impacts that are similar to those of the proposed Project. Additional pipeline infrastructure constructed to provide greater pipeline capacity between PADD II and PADD III would likely produce environmental impacts similar to those of the Gulf Coast Segment of the proposed Project. Oil shocks (unanticipated supply reductions that result in price spikes) arise through unstable crude oil supplies and would be more likely to occur under the No Action Alternative, as compared to the proposed Project, since crude oil supplies would continue to be sought from unstable foreign sources and transported over longer distances in the near term. Oil shocks reduce the amount of goods and services the U.S. can produce given a fixed amount of other inputs and cause some inputs (e.g., land, labor, and capital) to be under-utilized. In contrast, projects which stabilize crude oil supply through diversification and increased access to politically stable regions, such as the proposed Project, benefit the U.S. economy.

Under the No Action Alternative, in the near term positive socioeconomic impacts associated with construction and operation of the Project would not be realized along the proposed route and elsewhere in the U.S. No annual property tax revenues would be generated, as opposed to an estimated $138.4 million in annual property tax revenues that would be generated by the proposed Project in the region of influence. The generation of local employment as well as substantial expenditures on goods and services would also not occur under the No Action Alternative. However, if an alternative pipeline is constructed at some later date, socioeconomic benefits would be realized as a result of construction and operation of that alternative at that time.

GHG emissions associated with the proposed Project would not occur under the No Action Alternative, but GHG emissions would result from implementation of any alternative transportation network. EnSys (2010) employed both its World Oil Refining Logistics & Demand (WORLD) model and the DOE Energy Technologies Perspective (ETP) model to analyze effects of different transportation scenarios for the delivery of WCSB crude oil to world markets, including a scenario that equates to the No Action Alternative. The EnSys results indicated that with or without the proposed Project, there would be no

substantial change in total U.S. refining activity, total crude and product import volumes and costs, development rate in the oil sands, global refinery CO_2 emissions, and total life-cycle GHG emissions. However, the No Action Alternative, combined with a freeze of transport capacity for WCSB crudes at existing levels for 20 years, could lead to a reduction in WCSB oil sands production in the 2025 to2030 timeframe (EnSys 2010).

Construction of new pipelines, modification of existing ports, and/or the construction of new ports would produce environmental impacts within Canada or in the U.S. that would be similar in nature to those of the proposed Project in terrestrial environments. Port projects would also include construction impacts to marine environments and operational impacts associated with the handling and transport of crude oils in marine environments. In addition, the transport of crude oil by tanker would result in more GHG emissions than would transportation of crude oil by pipeline to the U.S.

4.1.3 Use of Alternative Energy Sources and Energy Conservation

Many commenters 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 III, is driven primarily by the demand for transportation fuels. Based on EIA (2010a, 2010b) statistics, approximately 78 percent of the refined product produced by PADD III refineries in 2009 was used for transportation fuel. The percentages of total production from PADD III 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 III 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 III refineries, and therefore 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 III to justify selection of the No Action Alternative as the preferred alternative. Although most refined products sold by PADD III 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 (Section 4.1.3.1);

- Use of Alternative Energy Sources in Place of Distillate Fuel Oil for Non-Transportation Uses (Section 4.1.3.2);
- Use of Alternative Energy Sources in Place of Residual Fuel Oil for Non-Transportation-Related Uses (Section 4.1.3.3); and
- Use of Alternative Energy Sources in Place of Other Non-Transportation-Related Refined Products (Section 4.1.3.4).

4.1.3.1 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. In the United States, the overall demand for crude oil is projected to remain relatively flat over the next 25 years (EIA 2010a). However, IEA (2010) projected that if policies and legislation were adopted to more aggressively respond to climate change in the United States by promoting fuel efficiency, electrification of motor vehicles, and/or alternative fuels, there could be a substantial reduction in demand for crude oil in the coming decades.

In general, commenters raised two general questions 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 U.S. 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?[26]

Outlooks for world and U.S. demand for crude oil indicate that even if there were a substantial reduction in U.S. consumption of crude oil (and/or relatively flat world-wide consumption), the market demand in PADD III 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 wide-spread adoption of fuel efficient vehicles, or deployment of alternate fuels (including vehicle electrification).

In early 2010, EPA prepared a report examining technically feasible measures that could reduce consumption of crude oil that is refined to produce transportation fuel (EPA 2010). The EPA study looked at two scenarios, which were informally characterized as somewhat aggressive and very aggressive, in attempting to reduce vehicle energy consumption and tailpipe emissions. In that report, EPA stated the following:

> "[The scenarios] do not reflect the entire range of possible outcomes, but rather, a set of outcomes that could occur, based on technical feasibility, if effective policy or market drivers were in place."

[26] Commenters also expressed concern about the potential effect that implementation of the proposed Project would have on adoption of policies to reduce crude oil demand. It is too speculative for NEPA purposes to attempt to predict how political factors might result in different policies or legislation being adopted in different scenarios. This section focuses on market demand issues related to more definitive factors such as fuel efficiency and alternate fuels since there several publicly available studies addressing those economic issues.

Among other factors underlying the somewhat aggressive scenario's assumptions were the following:

- Market penetration of just over 80 percent for hybrid electric, plug-in hybrid electric, and electric vehicles in the new light-duty vehicle sales in 2030;
- 5 percent annual improvement in GHG emission rates in light-duty vehicles through the 2030 time period;
- Current levels of household vehicle utility assumed to be maintained (e.g., range, towing capacity, and interior space);
- 2030 new vehicle fuel economy in light vehicles would be 36 miles per gallon (mpg) for gasoline vehicles, 60 mpg for hybrid electric vehicles, 74 mpg for plug-in hybrid electric vehicles, and a 150-mile range for electric vehicles;
- 12 percent annual reduction from light duty GHG emissions by 2030 from travel efficiency improvements (e.g., speed limit reductions, urban parking restrictions, congestion pricing, and eco-driving);
- For medium- and heavy-duty trucks it includes technology improvements in aerodynamics, tires, powertrain, limited adoption of hybrid into medium-duty applications, weight reduction through improved materials, and travel efficiency scenarios; and
- Similar technology improvements in efficiency, powerplant, aerodynamics, and materials for aviation, rail, and marine sectors.

EPA (2010) reported that implementation of the above measures could result in a reduction in demand for crude oil in the United States of 4 million bpd as compared to the projected demand in the EIA AEO by 2030. The findings of this EPA report were relied upon to construct the low-demand outlook modeled in the 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 U.S. and little impact on the total production from oil sands throughout the study timeframe. In the AEO demand outlook, 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.

IEA (2010) also addressed energy demand and production in three world-wide policy scenarios:

- 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 a scenario consistent with the goal to limit climate change to 2 ºC over pre-industrial levels, which equates to stabilizing GHG CO_2-equivalent emissions at 450 ppm.

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 projected the following levels of consumption in 2035:

- Current Policies Scenario – 107.4 million bpd;
- New Policies Scenario – 99 million bpd; and
- 450 Scenario – 81 million bpd.

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

- Current Policies Scenario – 4.6 million bpd;
- New Policies Scenario 4.2 million bpd; and
- 450 Scenario – 3.3 million bpd.

The projected 2035 consumption in each of these scenarios represents a substantial increase from 2009 consumption of approximately 1.3 million bpd oil-sands-derived crude oil. 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 assumed carbon price of $60 per ton in the New Policies Scenario and $120 per ton in the 450 Scenario). If oil-sands production is reduced to approximately 3.3 million bpd, then existing transboundary pipelines could accommodate import of that volume of oil-sands-derived crude oil into the U.S. However, that crude oil would not reach the refineries in PADD III.

Based on the outcomes of the EnSys (2010) report and 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 highly 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, Ross Morrow et al. (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 Ross Morrow et al. (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 GHG 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 CAFÉ standards. In contrast, the 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% 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 III (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. Finally, the EnSys analysis found that the import to or export from the United States of refined products was not sensitive to the seven pipeline scenarios considered.

It is reasonable to infer based on the EnSys (2010) results, when viewed in combination with the results from the Ross Morrow et al. (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 Ross Morrow et al. (2010) report concluded that increases in gasoline prices that 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, or countries around the world, adopt policies that would reduce the consumption of crude oil, 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. In addition, for all scenarios examined in the EnSys (2010) report, the total throughputs of oil-sands-derived crude oil at PADD III refineries was actually higher in the low-demand outlook than in the AEO outlook. This is because in the low-demand outlook, the reduction in demand for refined transportation fuels in PADD II leads to less oil-sands-derived crude oil being refined there. There would also be a reduction in demand for refined transportation fuels from PADD III refineries, but the volume of oil-sands-derived crude oil that would have been refined in PADD II would be rerouted to PADD III and would displace imports from other countries.

For these reasons, use of alternative energy sources and energy conservation in meeting needs for transportation fuel are not considered an alternative to the proposed Project.

4.1.3.2 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 III refineries in 2009 (EIA 2010a, 2010b). The distillate fuel oil was sold for use in the following categories listed by EIA (2010b):

- "Oil company";
- Industrial use;
- Commercial;
- Electrical power; and
- 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 III 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

III. 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 III 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 III 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 III 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 III refineries.

The use of distillate fuel oil produced by PADD III refineries for the generation of electrical power represents about 0.01 percent of the total output of PADD III refineries. Electrical generation currently fueled by residual fuel from PADD III 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 III 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 III refineries and there would be essentially no effect on the current and future crude oil needs of those refineries.

4.1.3.3 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 III 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 III refineries and the use of alternative fuels and conservation would have a negligible effect on the market demand for crude oil in PADD III.

4.1.3.4 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 II in 2009 was used for transportation purposes. The remaining 22 percent of PADD III 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 and 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 III production. For the most part, these three specialty products (as well the other specialty products produced by PADD III 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 III.

4.1.4 Summary

PADD III refineries currently import approximately 5.1 million bpd of crude oil, including 2.9 million bpd of heavy crude oil (EnSys 2010), the majority of which comes from Mexico, Venezuela, Saudi Arabia, and Nigeria. As reported by EnSys (2010), the demand for crude oil in PADD III is projected to increase and PADD III refinery runs are projected to grow over the next 10 years, even under the low demand outlook. At the same time, three of the four major PADD III crude oil suppliers currently face declining or uncertain production horizons (EnSys 2010). As a result, the market demand in PADD III for heavy crude oil from alternative sources is expected to increase in both the near term and further into the future. Implementation of the No Action Alternative would not meet this need for heavy crude oil in PADD III, unless a system alternative went forward to connect PADD II to PADD III or to directly transport WCSB crude oil to PADD III. Such alternatives would likely not receive regulatory approval prior to the proposed Project.

If the proposed Project, a similar pipeline system, or another transport mode is not constructed to transport WCSB crude oil to PADD III refineries, those refineries would be forced to rely on oil shipped by barge or tanker from areas outside of North America from regions which are experiencing declining production or are not secure and reliable sources of crude oil. As a result, in the near term, PADD III would continue to be dependent on less reliable and less stable foreign oil supplies from the Middle East, Africa, Mexico, and South America.

EnSys (2010) also projected that there would be no substantial change in total U.S. refining activity, total crude and product import volumes and costs, or global refinery CO_2 and total life-cycle GHG emissions whether or not the proposed Project is implemented. Additionally, EnSys (2010) determined that with implementation of the No Action Alternative, the production of crude oil from the Canadian oil sands projects would not be affected and that production would continue at current or higher levels through 2030 unless no other pipeline system or other projects were implemented to transport crude oil from the oil sands projects, an outcome that EnSys considered unlikely.

Under the No Action Alternative, crude oil from the WCSB would not have a ready conduit for export to available refineries and markets in PADD III, and it is therefore likely that alternative transportation systems to move oil to other markets would emerge. Crude oil would be transported by other proposed, planned, or existing pipelines or by alternative transportation methods (such as railroad tank cars, barges, or crude oil tankers) to markets in the global marketplace (these system alternatives are discussed in greater detail in Section 4.2). Several projects have been proposed or are planned to transport WCSB crude oil from the oil sands projects to ports in Canada and in the northwestern and northeastern U.S. Although it is not possible to identify the specific impacts of such projects, it is likely that the impacts of other pipeline projects would be similar in nature to those of the proposed Project. The extent and magnitude of the impacts would likely be different from project to project and would depend on the environmental conditions along the proposed routes. In addition, the transport of crude oil by tanker rather than by pipeline would likely result in greater transportation-related GHG emissions. Under the No Action Alternative, the near-term positive socioeconomic impacts associated with construction and

operation of the Project would not be realized along the proposed route and elsewhere in the U.S. No annual property tax revenues would be generated, as opposed to an estimated $138.4 million in annual property tax revenues that would be generated by the proposed Project in the region of influence. The generation of local employment as well as substantial expenditures on goods and services would also not occur under the No Action Alternative. However, if an alternative pipeline is constructed in the future, socioeconomic benefits would be realized as a result of construction and operation of that alternative.

Under the No Action Alternative, improved fuel efficiency and broader adoption of alternative fuels would not likely substantially alter the demand for WCSB heavy crude oil at PADD III refineries for the production of transportation fuels. Other energy sources could potentially replace the energy derived from non-transportation-related uses of PADD III refinery output. However, the non-transportation uses of PADD III refinery output represent a very small percentage of total PADD III refinery output. Therefore, the No Action Alternative would have little effect on overall demand for refinery products that are currently sold by PADD III refineries for non-transportation uses.

As a result of these considerations, DOS does not regard the No Action Alternative to be preferable to the proposed Project.

4.2 SYSTEM ALTERNATIVES

System alternatives to the proposed Project would make use of other existing, modified, proposed or planned pipeline systems, or other transportation systems to meet the purpose of and need for the proposed Project. With implementation of a system alternative to meet the objectives of the Project, the Project would not be constructed and the impacts described in this EIS would not occur. However, as noted below, there would be environmental impacts associated with any system alternative that would meet the purpose and need of the proposed Project. Each system alternative considered was screened for its potential environmental effects versus similar environmental effects for the proposed Project, technical and economic practicability, and the ability to meet the purpose of and need for the proposed Project.

The system alternatives screened include the following:

- Use of Existing or Expanded Pipeline Systems (Section 4.2.1);
- Use of Other Proposed or Planned Pipeline Systems (Section 4.2.2); and
- Alternative Modes of Transportation (Section 4.2.3).

4.2.1 Use of Existing or Expanded Pipeline Systems

Four existing pipeline systems were considered as potential system alternatives. Those systems are described and assessed in the following sections:

- ExxonMobil Pegasus Pipeline (Section 4.2.1.1);
- Express-Platte Pipeline System (Section 4.2.1.2);
- Keystone Oil Pipeline Project (Section 4.2.1.3); and
- Alberta Clipper Pipeline Project (Section 4.2.1.4).

4.2.1.1 ExxonMobil Pegasus Pipeline

There is currently only one pipeline system that extends from the Midwest to the Gulf region: the ExxonMobil Pegasus Pipeline. That system currently transports up to 96,000 bpd of Canadian crude oil from Patoka, Illinois to Nederland, Texas. As described in Section 1.1 the proposed Project would initially transport approximately 535,000 bpd of crude oil to the Cushing tank farm and to delivery points in Texas. Therefore, the Pegasus pipeline would not be capable of delivering the proposed Project's WCSB crude oil volume even if used to full capacity, particularly since most of its capacity is already dedicated to crude oil transport from PADD II to PADD III. Delivering the volumes contracted to the proposed Project would require a substantial expansion of the Pegasus pipeline. Any future expansion of the Pegasus pipeline system would result in impacts along the 835-mile-long route between Patoka and Nederland that would be broadly similar to those of the proposed Project, albeit over a shorter total distance.

In summary, the existing Pegasus pipeline cannot be used to meet the proposed Project's objectives in the near term and there are no announced plans to expand the pipeline. Therefore, the Pegasus Pipeline was not further considered as a system alternative to the proposed Project.

4.2.1.2 Express-Platte Pipeline System

The Express-Platte Pipeline System is a 1,700-mile-long oil transportation network that connects Canadian and U.S. producers to refineries in the Rocky Mountain and Midwest regions of the U.S. The system consists of two crude oil pipelines – the Express Pipeline and the Platte Pipeline. The Express Pipeline transports a variety of light, medium, and heavy crude oil from Hardisty to markets in Montana, Wyoming, Utah, and Colorado, and has a capacity of 280,000 bpd. The Express Pipeline connects to the Platte Pipeline system at Casper, Wyoming. The Platte system transports crude oil from Casper to Wood River, Illinois and has a capacity of 164,000 bpd from Casper to Guernsey, Wyoming. From Guernsey to Wood River, the system has a capacity of 145,000 bpd.

The Express-Platte Pipeline System originates in Hardisty, as would the proposed Project, and passes close to the northern end of the Cushing Extension (near Steele City, Nebraska). However, the Express system has firm commitments for 235,000 bpd that will not expire until 2012 and 2015 and would therefore not have sufficient capacity to meet the market demand to which the proposed Project is responding without a major expansion of the system. In addition, to meet the market demand for heavy crude oil at PADD III refineries and to the Cushing area, use of the Express-Platte Pipeline System as a system alternative would require either (1) a short pipeline to connect to the northern end of the Cushing Extension along with a new pipeline to the Gulf Coast that would likely be similar to the proposed Gulf Coast Segment of the proposed Project, or (2) a new pipeline from the existing Express-Platte pipeline to the Gulf Coast. Either expansion alternative would result in environmental impacts from the northern end of the Cushing Extension to the Gulf Coast delivery points that would be broadly similar to or greater than the Gulf Coast Segment of the proposed Project.

In summary, the existing Express-Platte pipeline cannot be used to meet the proposed Project's objectives in the near term, and expansion of the system to meet the capacity requirements of the proposed Project would not be environmentally preferable to construction and operation of the proposed Project. Therefore, the Express-Platte Pipeline System was not further considered as a system alternative to the proposed Project.

4.2.1.3 Keystone Oil Pipeline Project

The Keystone Oil Pipeline Project extends from the U.S. border in North Dakota to Patoka, Illinois; it also includes the Cushing Extension which extends from Steele City, Nebraska to Cushing, Oklahoma. It currently has the capacity to transport 435,000 bpd of WCSB crude from Canada to refineries in PADD II. On December 22, 2010, Argus.com (2010) reported that the existing Keystone Oil Pipeline was transporting approximately 250,000 bpd of crude oil.

Keystone has firm contracts to transport 380,000 bpd on the proposed Project and intends to also transport 155,000 bpd of crude oil on the proposed Project to Cushing, Oklahoma that was originally contracted for transport on the existing Keystone Oil Pipeline for a total initial throughput of 535,000 bpd. For the existing Keystone Pipeline to serve as a system alternative to the proposed Project, it would first need to accommodate its current obligations to ship 155,000 bpd to the existing Cushing terminal and 340,000 bpd to Wood River and Patoka, Illinois, or a total current commitment to ship 495,000 bpd. The excess capacity of the Keystone Pipeline based on these commitments is 96,000 bpd. The Keystone Pipeline does not have the capacity to transport the additional crude oil currently contracted on the proposed Project, and therefore this potential system alternative could not meet the proposed Project objectives without a major expansion in both Canada and the U.S. In addition to the expansion of existing facilities, it would be necessary to construct a pipeline from Cushing to the Gulf Coast area of PADD III that would be essentially the same as the Gulf Coast Segment of the proposed Project. The overall expansion would result in environmental impacts that would be similar to those of the proposed Project, and would require federal permits in both Canada and the U.S. as well as applicable provincial, state, and local permits.

In summary, the existing Keystone Oil Pipeline cannot be used to meet the proposed Project's objectives in the near term, and due to the overall system expansion required, it would not offer an overall environmental advantage over the proposed Project. Therefore, the existing Keystone Oil Pipeline was not further considered as a system alternative to the proposed Project[27].

4.2.1.4 Alberta Clipper Pipeline Project

Commenters on the draft EIS have suggested that Enbridge's Alberta Clipper Pipeline Project could be used to transport crude oil from Hardisty to Cushing. The Alberta Clipper Pipeline extends from Hardisty to Superior, Wisconsin and has the current capacity to deliver an average of 450,000 bpd of crude oil from a supply hub near Hardisty to an existing terminal in Superior with a potential maximum capacity of 800,000 bpd assuming additional pumping capacity is added at appropriate locations along the pipeline corridor. During the NEB hearings on the proposed Project, Enbridge made public its position that Keystone could establish a connection to the Alberta Clipper Pipeline near Gretna, Manitoba, construct a pipeline adjacent to the existing Keystone Oil Pipeline to the Cushing Extension, and construct a new pipeline from the southern end of the Cushing Extension to PADD III delivery points. However, during the NEB hearings, Enbridge did not indicate what capacity it would make available to Keystone on its pipeline. To meet flow requirements of the proposed Project, the Alberta Clipper Pipeline would have to be expanded in Canada which would result in additional impacts from the U.S./Canada border to Hardisty. Keystone has stated that the concept introduced by Enbridge at the NEB hearings would require commercial negotiation of acceptable terms and conditions among Keystone, Enbridge and its stakeholders, and shippers on the proposed Project. Keystone and Enbridge discussed the concept further in March 2009 at a meeting arranged by CAPP. Minutes of the meeting were filed as part of the NEB record. As a result of that meeting, Keystone identified business issues of concern and requested a proposal from Enbridge to resolve those issues but did not receive a response. The NEB did not pursue

[27] An alternative route that would parallel the existing Keystone Oil Pipeline Project in the U.S. is addressed in Section 4.3.3.4.

this alternative to the proposed Project beyond limited questioning by the members of the NEB and its staff.

This potential system alternative would require expansion of existing infrastructure and would produce impacts in Canada and the U.S. similar to those for the Keystone Oil Pipeline system alternative described in Section 4.2.1.3. Additionally, it is not clear that the initial committed flow volumes (535,000 bpd) of the proposed Project could be accommodated by this system alternative due to the contractual issues described above even if the Alberta Clipper system was expanded to its maximum capacity of 800,000 bpd. As a result, the Alberta Clipper Pipeline Project was not considered further as a reasonable system alternative for the proposed Project.

4.2.2 Use of Other Proposed or Planned Pipeline Systems

Other new pipeline system alternatives have been proposed or planned by proponents that if successfully designed, permitted, and constructed could transport crude oil from the oil sands of the WCSB to the PADD III market, either via a direct link from the WCSB to PADD III, or by interconnecting to existing pipeline systems that transport WCSB crude oil into PADD II. For a potential new pipeline system to be considered a viable alternative to the Project, it must meet the purpose of and need for the Project as described in Section 1.2.

The proponents of five of the potential system alternatives described below initially announced conceptual plans for the projects and then either abandoned the plans or put them on hold. None of those proponents have established commercial commitments through open seasons and have not submitted permit applications as of this writing. Although at this time the possibility of the future development of those projects is speculative, they are described below and assessed relative to their potential to meet the proposed Project's objectives. The sixth project considered, the Enbridge Monarch Pipeline, is in the early planning stage.

The seven potential pipeline system alternatives considered are described in the following sections:

- Altex Pipeline System (Section 4.2.2.1);
- Chinook-Maple Leaf Pipeline System (Section 4.2.2.2);
- Texas Access Pipeline (Section 4.2.2.3);
- Enbridge Trailbreaker Project (Section 4.2.2.4);
- Enbridge-BP Delivery System (Section 4.2.2.5);
- Enbridge Monarch Pipeline (Section 4.2.2.6); and
- Seaway Pipeline (Section 4.2.2.7).

4.2.2.1 Altex Pipeline System

Plans for the Altex (Alberta-Texas) Pipeline System were initially announced in 2005 by the Calgary-based energy infrastructure-development company, Altex Energy Ltd. The planned Altex Pipeline System included a 2,360-mile-long greenfield pipeline system that would originate north of Fort McMurray, Canada, extend to the Redwater-Fort Saskatchewan area, and from there to Hardisty, Alberta. From Hardisty south it would cross the U.S./Canada border in Montana and extend southeast through Montana, Wyoming, South Dakota, Nebraska, Kansas, Oklahoma, and Texas to the Port Arthur area. As initially planned, service would start no sooner than 2013, with a proposed initial crude oil capacity of 425,000 bpd. In 2008, Altex determined that the project as planned was not economically viable and

therefore did not pursue it further. Thus, there has not been an open season, shipper commitments, or an application for a Presidential Permit or other permits in the U.S. and the planned Altex Pipeline System was not considered further as a system alternative to the proposed Project.

After determining that the Altex Pipeline System would not be viable in the near term, Altex concluded that it could develop an interim transportation system that would be financially acceptable during the period that oil sands production increased to the point of making the Altex Pipeline System economically viable. As stated by Altex, the plan would involve transporting bitumen by rail to virtually any market within North America. In 2008, the Canadian National Railway and Altex developed a conceptual plan to accomplish transport of bitumen, not crude oil (termed Pipeline*OnRail*™).

Altex has negotiated long-term rail rates with Canadian National and is offering transportation services in Canada to bitumen producers at rates less than the cost of their pipeline transportation alternatives. To support shippers' needs, Altex stated that it intends to construct terminals near Peace River, Ft. McMurrary, and possibly Ft. Saskatchewan, Alberta. The use of rail as an alternate mode of transportation is addressed in Section 4.2.3.2 (Railroad Tank Car Transport).

4.2.2.2 Chinook-Maple Leaf Pipeline System

The Chinook-Maple Leaf Pipeline System was a conceptual project originally considered by Kinder Morgan and TEPPCO (now merged with Enterprise Products Partners, LP). This 2,050-mile-long pipeline system would originate near Hardisty, Alberta and cross the U.S./Canada border from Alberta into Montana. It would then traverse Montana, Wyoming, Colorado, Kansas, Oklahoma, and Texas to deliver crude oil to the Houston area. The northern portion of the route would be adjacent to the existing Kinder Morgan Express Pipeline.

The Chinook-Maple Leaf system was planned to have a capacity of 440,000 bpd between Hardisty and Cushing (Chinook Pipeline), and 550,000 bpd between Cushing and Houston (Maple Leaf Pipeline). If this system were not fully subscribed it could transport a portion of the oil planned for transport in the proposed Project; however, it would not have the capacity to meet the market demand to which the proposed Project is responding (firm contracts to deliver 535,000 bpd across the border, with 155,000 bpd delivered to Cushing and 380,000 bpd delivered to the Gulf Coast).

The proponents initially indicated a planned in-service date of late 2011 or early 2012 (CAPP 2008). However, at the time this EIS was prepared the proponents had not announced an open season or shipper commitments or applied for a Presidential Permit or other permits in the U.S. In addition, neither company lists the Chinook-Maple Leaf Pipeline System as a potential future project. Therefore, the Chinook-Maple Leaf Pipeline System was not considered further as a system alternative to the proposed Project.

4.2.2.3 Texas Access Pipeline

In December 2007, Enbridge and ExxonMobil Pipeline Company announced plans for a new pipeline system that would transport crude oil from Patoka, Illinois to the Texas Gulf Coast. The proponents indicated that the crude oil transported in the Texas Access Pipeline from Patoka would originate in the Canadian oil sands region of Alberta. The conceptual plan included a 738-mile-long, 30-inch-diameter pipeline that would transport the oil from Patoka to refineries in Nederland, Texas, and an 88-mile-long, 24-inch-diameter pipeline that would transport crude oil from Nederland to a delivery point in an area east of Houston. The initial capacity of the Patoka-to-Nederland segment of the pipeline would be 445,000 bpd, and the initial capacity of the Nederland-to-Houston segment would be 169,000 bpd. If this system were not fully subscribed it could transport a portion of the oil planned for transport in the proposed

Project. However, it would not have the capacity to meet the market demand to which the proposed Project is responding (firm contracts to deliver 535,000 bpd across the border, with 155,000 bpd delivered to Cushing and 380,000 bpd delivered to the Gulf Coast) without a major expansion.

The proponents did not receive sufficient interest in the project from shippers to justify the construction costs and the Texas Access Pipeline has not progressed. In 2008, Enbridge stated that, based on current market conditions, the project would not go forward and indicated that "it will likely be required as a large-volume solution, probably in the 2014 area." Therefore, the Texas Access Pipeline was not considered further as a system alternative to the proposed Project.

4.2.2.4 Enbridge Trailbreaker Project

In 2008, Enbridge proposed the Trailbreaker Project as an interim option to the Texas Access Pipeline for supplying crude oil to PADDs II and III. As announced, the Trailbreaker Project would involve shipping crude oil by pipeline to the northeastern U.S. and transporting crude oil by tanker from there to PADD III as early as mid 2010. The project would have allowed the transport of WCSB oil production to refineries in Ontario, Quebec, the Canadian Maritime Provinces, and U.S. markets. It would have included an expansion of the existing Enbridge Line 6B from Chicago, Illinois to Sarnia, Ontario, as well as terminal expansions and upgrades, increasing the capacity of existing Enbridge Line 7 between Sarnia and Westover, Ontario, and the reversal of the existing Enbridge Line 9 to flow from Sarnia east to Montreal, Quebec. Another component of the project would have been the reversal of the pipeline owned by Portland-Montreal Pipe Line (PMPL), which transports product from Portland, Maine to Montreal. In late 2008, PMPL completed an open season to gauge shipper interest in the proposed reversal; however, they did not receive the level of firm volume commitments required to proceed at that time. In January 2010, Enbridge announced that the Trailbreaker Project was dormant, and the project is no longer included in commercial opportunities in investor presentations. Therefore, the Trailbreaker Project was not considered further as a system alternative to the proposed Project.

4.2.2.5 Enbridge-BP Delivery System

In 2008, Enbridge and BP announced that they had entered into an agreement to develop the Enbridge-BP Delivery System to transport WCSB heavy crude oil from Flanagan, Illinois, to Houston and Texas City, Texas, using a combination of existing facilities, new pipeline, and looped pipeline construction where required. As initially announced, the project would traverse parts of Illinois, Missouri, Kansas, Oklahoma, and Texas and would be in service by late 2012 with an initial total system capacity of 250,000 bpd to the Gulf Coast. Enbridge and BP intended to use the BP #1 System and other existing pipelines north of the Cushing crude oil hub with some new pipeline construction south of Cushing to connect to markets in Houston and possibly in Nederland. From Flanagan (where the system would interconnect with the Enbridge Southern Access pipeline) to Cushing the capacity would be approximately 140,000 bpd for further transport to Gulf Coast markets. The remaining 110,000 bpd would originate from interconnecting pipelines at Cushing.

At the NEB hearings for the proposed Project, Enbridge stated that the project is still on the books but is suspended. The project is not listed as a potential opportunity in investor presentations. Therefore, the Enbridge-BP Delivery System was not considered further as a system alternative to the proposed Project.

4.2.2.6 Enbridge Monarch Pipeline

In late 2010, Enbridge announced plans for a 24-inch-diameter pipeline that would extend from its oil terminal in Cushing to the Gulf Coast. The pipeline would have an initial capacity of approximately 150,000 bpd, with the ability to expand to about 350,000 bpd. The objective of the Monarch Project is to

alleviate a bottleneck for light crude oil at Cushing and provide a transportation route from Cushing to the Gulf Coast refineries in PADD III. No further information was available on the project at the time this EIS was prepared.

Although Enbridge has stated that the Monarch Pipeline would transport some heavy crude oil, it is being designed and proposed to transport lighter crudes to the Gulf Coast. Even without the transport of lighter crudes, its maximum capacity would not be sufficient to satisfy market demand to which the proposed Project is responding (firm contracts to deliver 380,000 bpd to the Gulf Coast). Finally, it would be necessary to construct a pipeline to Cushing to supply the WCSB crude oil. The impacts of construction of that pipeline and construction of the Monarch Pipeline would result in impacts that would be similar in nature and extent to those of the proposed Project along the same approximate distance.

Based on the above considerations, the Enbridge Monarch Pipeline was not further considered as a system alternative to the proposed Project.

4.2.2.7 Seaway Pipeline

ConocoPhillips owns the 530-mile-long Seaway pipeline system (operated by Enterprise Products Partners LP) which transports crude oil from the Houston area to storage facilities at Cushing. The pipeline has a capacity of approximately 350,000 bpd. The system also supplies crude oil to refineries in the Houston area and has a usable storage capacity of 3.4 million barrels. In 2007, the former operator of the pipeline (Teppco Partners, LP) stated it would consider reversing the line to transport crude oil from Cushing to PADD III. However, Bloomberg (2011) stated that ConocoPhillips had decided that it would not reverse the pipeline. As a result, the Seaway pipeline was not further considered as a system alternative to the proposed Project.

4.2.3 Alternative Modes of Transportation

Three modes of surface transportation of crude oil from the U.S./Canada border near Morgan to Cushing, Nederland, and Moore Junction were considered as alternatives to the proposed Project as described in the following sections:

- Truck Transport (Section 4.2.3.1);
- Railroad Tank Car Transport (Section 4.2.3.2); and
- Barge and Marine Tanker Transport (Section 4.2.3.3).

4.2.3.1 Truck Transport

The transport of crude oil by truck is occasionally done to serve as an interim transportation solution for smaller volumes of crude oil or petroleum product. For example, due to pipeline limitations in the Bakken oil field in Montana and North Dakota, a portion of the crude oil produced in that area is currently transported by tank truck. However, transport by truck is not a reasonable alternative to transport the volume of oil that would be shipped by the proposed Project. Large tank trucks have a maximum volume of about 9,000 gallons (about 214 barrels). It would therefore require about 2,500 trucks per day to transport the 535,000 bpd that the Project would initially transport. To sustain a delivery rate of 535,000 bpd, as many as twice that number of trucks would likely have to be devoted exclusively to traveling to and from the border and the delivery points.

Table 4.2.3-1 summarizes accident statistics by method of transport compiled by Association of Oil Pipe Lines (AOPL). As indicated in the table, transport of oil by pipeline is substantially safer than transport

by trucking. AOPL reported that trucking is 87 times more likely than pipeline transport to result in a human fatality. In similar findings, fire and/or explosions are 35 times more likely when transporting crude oil via truck. Vehicle accidents and accidental releases are also concerns with surface transportation crude oil delivery. The Bureau of Transportation Statistics (2009) reported that the transport of hazardous liquids (including crude oil) on highways resulted in five times as many fatalities as transportation of hazardous liquids by pipeline between 1975 and 2007.

TABLE 4.2.3-1
Reported Incident Rates for Alternative Methods of Liquids Transport

Method of Transport [a]	Death	Fire/Explosion	Injury
Truck	87	35	2
Rail	3	9	0.1
Barge	0.2	4	4
Tank Ship	4	1	3
Pipeline	1	1	1

[a] Relative rates were calculated based on incidents per ton-mile for each transportation mode (AOPL 2004).

The trucking alternative would add substantial congestion to highways in all states along the route selected, particularly at and near the border crossing and in the vicinity of the delivery points. At those locations it is likely that there would be significant impacts to the existing transportation systems. The trucks would consume millions of gallons of fuel per year, with subsequent exhaust emissions (including GHG) and other negative environmental effects. Trucking would likely be subject to interruptions due to unfavorable weather and road conditions, especially in Montana and other northern states. At the Gulf Coast delivery points, surface transportation would necessitate substantial new transfer facilities and personnel.

As a result of these considerations, truck transportation was not considered a reasonable alternative to meeting the Project objectives and was not further evaluated.

4.2.3.2 Railroad Tank Car Transport

As noted in Section 4.2.2.1, Altex and the Canadian National Railway have developed a transportation strategy termed Pipeline*OnRail*™ to move oil sands production to markets in North America or Asia. At the end of 2010, the system was shipping approximately 10,000 bpd within Canada from producers whose reserves are stranded without pipeline access. The system reportedly could have the capacity to ship up to 4 million bpd throughout North America (Financial Post 2009). Canadian National stated that it can ship crude oil directly into the U.S. or to the Canadian west coast for shipment to Asia. The system would use insulated and heated double-hulled tank cars to ship bitumen or would ship bitumen diluted with condensates or other diluents (CN 2010). Canadian National also stated that the rail system to the west coast of Canada is already in place and it could ship 2.6 million bpd to the west coast of Canada if 20,000 tank cars were added to its fleet. It further stated that the increase in the number of rail tank cars in use would not clog its system in Canada (Financial Post 2010). As noted in The Globe and Mail (2011), Canadian National is currently transporting crude oil from the Bakken area of southern Saskatchewan to the U.S. Gulf Coast. However, only 250 to 300 rail cars of crude oil per month are being transported, or up to 10,000 bpd. In addition, it is not clear that there is an interconnecting rail network from the Morgan, Montana are to either Cushing or the Gulf Coast to cost-effectively ship the oil.

The maximum size tank car allowed by regulations in 49 CFR 179.13 is 34,500 gallons (about 820 barrels). Use of these cars to ship 535,000 bpd would require approximately 650 rail tank cars per day at the delivery sites and returning to Canada. At maximum capacity, approximately 1,010 rail tank cars would be required to unload at the delivery points each day. It is likely that unit trains would be created and devoted exclusively to the Project, with each train consisting of from 60 to 100 tank cars. Transporting the maximum throughput of 830,000 bpd would require from about 10 to 17 unit trains delivering oil to the receipt points each day, as well as at least the same number of trains making the return trip. It is possible that for continuous operation, the transporters may need to have additional trains in transit along the route or routes selected.

The number of train trips required would likely affect traffic on the existing rail system in the vicinity of the route used from the Canadian border to the Gulf Coast For example, this volume of rail traffic may result in periodic or long-term rerouting of some existing train traffic in the regions of the route selected by Canadian National. This alternative would also directly affect communities that have rail lines that would be used for this transport or by creating delays on the rail lines due to the substantial increase in rail traffic across railroad crossings of roads. There would likely be indirect impacts to some communities due to the redirection of some existing rail traffic to other rail lines and due to increased traffic on those lines. This alternative would also substantially increase noise along the route selected and in communities indirectly affected due to increases in redirected train traffic. In addition, there would be an increase in the emission of combustion products due to the use of diesel engines which could have an adverse impact on air quality along the route selected. As compared to the proposed Project, this alternative would have substantially greater GHG emissions during operation due to the combustion of diesel fuel.

Interruptions in the delivery of crude oil would be more likely than with the proposed Project due to conditions such as weather and congestion of the rail lines. Although there are deliveries of large volumes of crude oil and petroleum products by rail tank car unit trains in some areas of Russia and China, and perhaps elsewhere in Asia, there are no such major delivery systems in the U.S. Investments are currently being made to move up to 200,000 bpd of Bakken crude oil out of Montana and North Dakota to refineries elsewhere in the United States, including the Gulf Coast. However, to meet the market demand to which the proposed Project is responding, development of a rail tank car system would likely require substantial new approaches to delivery systems and new infrastructure, including spur lines, train storage yards at the delivery points, additional oil storage facilities, and upgrades to existing rail lines. The impacts of development of such a system would likely be similar to those of the proposed Project, but may not occur along the same distance as those of the proposed Project since many existing rail lines may be available for use. However, substantial areas would be required for train storage and spur lines at or near the delivery points. For many resources, the impacts of constructing this alternative on key resources would likely be less extensive than those of the proposed Project. However, as noted above, during operation the impacts on communities in the vicinity of the route selected and in communities affected by redirected rail traffic would be greater than those of the proposed Project during operation.

As noted in Table 4.2.3-1, rail transport of liquids is not as safe a mode of transportation as pipelines. With the number of trains and tank cars required to transport volumes of crude oil similar to those of the proposed Project, the safety of communities along the route could be an issue of concern. The maximum release of oil from a train accident would likely be less than the maximum possible release from the proposed Project.

The use of rail tank cars for delivery of WCSB crude oil may not be as cost-effective as transport by pipeline and may result in higher transportation costs. Although the Canadian National website has

suggested that transport prices on rail are at least competitive with pipeline tariffs, the EnSys (2010) report states the following regarding Pipeline*OnRail*™:

> "This study did not allow for the expansion of the PipelineOnRail capacity in any scenario because tariffs for rail are generally not considered attractive relative to pipelines. However, during a period of constrained pipeline capacity, the PipelineOnRail could compete as an alternative."

In summary, development of a rail system to transport the volume of crude oil that would be transported by the proposed Project would likely produce less impact from construction than would the proposed Project. However, there would likely be greater safety concerns and greater impacts during operation, including higher energy use and GHG emissions, greater noise impacts, and greater direct and indirect effects on many more communities than the proposed Project. Rail transportation would also be subject to more frequent delivery interruptions than the proposed Project. As a result, transportation of crude oil by rail tank car from the Canada/U.S. border to delivery points in PADDs II and II would not offer an overall environmental advantage over the proposed Project and was eliminated from further consideration.

4.2.3.3 Barge and Marine Tanker Transport

Inland transport of crude oil by barge to PADD III from the U.S./Canada border near Morgan would require an inland waterway capable of supporting barge traffic to Cushing and to PADD III. However, there is no inland waterway that could accommodate that traffic and therefore barge transport of crude oil to the delivery points at Cushing and in Texas was not considered a reasonable alternative.

Marine transport by either barge or marine tanker would require that crude oil be transported from the WCSB producers to ports on either the east or west coasts of Canada or the U.S. The Enbridge Trailbreaker, discussed in Section 4.2.2 as a system alternative, was a previously proposed transportation plan that would have transported crude oil to a northeast U.S. port and shipped it by marine tanker to PADD III. However, that project is not being actively pursued by Enbridge and was not further considered as a system alternative to the proposed Project. In addition, although marine transport by either barge or tanker to PADD III would be possible, it would require other forms of transport as well to reach Cushing, and therefore would not meet all proposed Project objectives without additional infrastructure.

As noted in Section 4.1, there are several proposed projects that would transport WCSB crude oil to the Canadian west coast for transport from existing, modified, or new marine terminals. Although those projects could be considered potential system alternatives, implementation of the projects would not be possible in the time frame necessary to meet the proposed Project objectives. Construction of those projects would have impacts that would be similar in nature, extent, and magnitude as those of the proposed Project, although the impacts would likely occur only in Canada.

Transport of crude oil by marine tanker or barge would result in substantially more energy consumption than transport by the proposed Project and would result in substantially more GHG emissions than during operation of the proposed Project. As noted in Table 4.2.3-1, both marine tanker and barge transport of hazardous liquids have greater safety concerns than transport by pipeline. Additionally, this method of transport to the Gulf Coast would be more costly than transport by pipeline.

In summary, marine transport of WCSB crude oil would not meet the proposed Project objectives, would result in greater energy consumption and GHG emissions, would increase the cost of delivered crude oil to the Gulf Coast refineries, and would have greater safety concerns than the proposed Project. Therefore, marine transport of WCSB crude oil was not further considered as a system alternative to the proposed Project.

4.3 MAJOR ROUTE ALTERNATIVES AND ROUTE VARIATIONS

4.3.1 Introduction

DOS considered potential alternative routes to determine whether or not there are route alternatives that would avoid or reduce impacts to environmentally sensitive resources as compared to the impacts of the proposed Project while meeting the objectives of the proposed Project. In identifying route alternatives, consideration was given to suggestions received from tribes, agencies, and the public during the scoping period and in comments on the draft EIS. In addition, variations to the proposed route were also considered. Variations are relatively short deviations from a proposed route that are developed to resolve or reduce construction impacts to localized, specific resources such as cultural resource sites, wetlands, recreational lands, residences, and terrain conditions.

This section addresses major route alternatives by segment and route variations in the following subsections:

- Approach (Section 4.3.2);
- Alternative Routes for the Steele City Segment (Section 4.3.3);
- Alternative Route for both the Steele City Segment and Cushing Extension (Western Alternative; Section 4.3.4);
- Alternative Routes for the Gulf Coast Segment (Section 4.3.5);
- Alternative Routes for the Houston Lateral (Section 4.3.6); and
- Route Variations (Section 4.3.7).

The agency preferred route is presented in Section 4.3.8.

4.3.2 Approach

The alternatives analysis was conducted as a screening process that involved the following steps:

- Establish criteria for screening alternatives;
- Identify potential alternatives that meet the criteria;
- Determine whether the potential alternatives could meet the purpose and need of the proposed Project and whether or not they would be technically and economically practicable; and
- For those alternatives that could meet the purpose and need of the proposed Project and appear to be technically and economically practicable, determine whether or not an alternative offers an overall environmental advantage over the proposed route. If it was determined that the potential alternative would not offer an overall environmental advantage, it was eliminated from further consideration.

4.3.2.1 Screening Criteria

Control Points Criterion

The control points are locations where alternatives would have to begin and end to meet the Project objectives. These fixed control points, which placed geographic constraints on potential alternatives, consisted of the following:

- The U.S./Canada border crossing between Saskatchewan and Montana near the town of Morgan, Montana where the pipeline of the Canadian portion of the proposed pipeline terminates (the Canadian portion of the pipeline has already been permitted) – that control point is the northern end of the Steele City Segment;
- The northern end of the existing Cushing Extension of the Keystone Oil Pipeline near Steele City, Nebraska – that control point is the southern end of the Steele City Segment;
- The southern end of the Cushing Extension in Cushing, Oklahoma – that control point is the northern end of the Gulf Coast Segment;
- The crude oil delivery point in PADD III at Nederland, Texas – that control point is the southern end of the Gulf Coast Segment; and
- The crude oil delivery point near Moore Junction, Texas – that control point is the southwestern end of the Houston Lateral.

These control points provide the basic framework for identifying alternative routes. However, as described in Section 4.3.3.1, in response to an agency scoping comment and comments on the draft EIS regarding alternatives, we also considered alternatives that originated at Hardisty, Canada and extended into the U.S. at a point other than near Morgan.

The control points at the northern and southern ends of the Cushing Extension were established to take advantage of the nearly 300 miles of 36-inch-diameter pipe that is currently in place and available for use by modifying the operation of the existing Keystone Oil Pipeline. Use of the Cushing Extension would avoid the impacts associated with construction of a pipeline of similar length. However, as described in Section 4.3.4, an alternative to using the Cushing Extension was also identified and evaluated.

Avoidance Criterion

The second criterion established was to avoid or minimize effects to or crossing of the following areas to the extent practicable:

- Public lands (except in Montana, where there is a state regulatory preference for the use of public lands; this issue is addressed in Appendix I to the draft EIS and in Section 4.3.7);
- Large waterbodies and water control structures;
- Rugged terrain that could impact constructability;
- Large wetland complexes;
- Highly developed urban areas and urban infrastructure;
- Properties listed on the NRHP;
- Wildlife refuges and management areas;
- Key waterfowl use or nesting areas;
- Irrigated croplands;
- Forested areas, including commercial forest lands; and
- Residences and outbuildings.

Although the alternatives identified avoided or minimized crossings of these areas to the extent possible, the extent, shape, and prevalence of many resources (e.g., rivers, historical trails, wetlands, and farmlands) preclude completely avoiding impacts to them on any selected route, particularly for a route that would extend from the U.S./Canada border to the Gulf Coast.

Many commenters on the draft EIS requested that DOS consider avoidance of or minimization of pipeline length in the Sand Hills topographic region of Nebraska as well as areas in Nebraska underlain by the NHPAQ system. These commenters considered that the potential for accidental oil releases associated with the proposed Project operations would lead to unacceptable risk to the NHPAQ system and that the potential for erosion in the Sand Hills topographic region associated with the proposed Project construction would lead to unacceptable environmental degradation The NHPAQ system extends across approximately 64,400 square miles of Nebraska, essentially underlying all but the eastern-most portion of the state. Almost all reasonable potential routes through Nebraska from the control point at Morgan, Montana to the control point at the northern end of the existing Cushing Extension would cross the NHPAQ system, including the existing Keystone pipeline corridor. DOS has addressed these concerns in Sections 3.2, 3.3, and 3.13. Key findings of the analyses in these sections include:

- As discussed in Section 3.13, experience from previous oil pipeline releases in shallow groundwater areas with conditions similar to those within the NHPAQ system indicates that the impacts from even very large spills would likely be limited to localized groundwater contamination that would not threaten the regional viability of the aquifer system.
- The proposed Project would be constructed and operated using standard PHMSA regulatory requirements for pipeline construction and operation in 49 CFR 195 as well as a set of even more stringent Project-specific Special Conditions developed in consultation with PHMSA and agreed to by Keystone. Standard PHMSA requirements are described in greater detail in Sections 2.3 and 3.13.1 as are the Project-specific Special Conditions that are also provided in Appendix C of the SDEIS. In aggregate, these procedures would substantially reduce the potential risk of an accidental oil release from the pipeline anywhere along the proposed Project corridor. Based on the most recent PHMSA data for incidents associated with hazardous liquid pipelines (see Section 3.13.3.2), there is a statistical probability of 0.0007 incidents per mile of pipeline per year. These incident statistics include all releases from pipelines of all ages and are therefore conservative when comparing to potential risk from new pipelines designed consistent with current regulations, industry standards, and with the 57 Project-specific Special Conditions developed in consultation with PHMSA that would apply to the proposed Project.
- During the proposed Project design effort, local Natural Resources Conservation Service (NRCS) offices and regional experts on Sand Hills reclamation from the University of Nebraska, University of South Dakota, and Nebraska Department of Roads were consulted and their recommendations on routing, construction techniques, and restoration techniques to minimize potential damage to Sand Hills vegetation were incorporated into the proposed Project plan and would be incorporated into the implementation of any alternative route across the Sand Hills (see Section 3.2.2.1 of the SDEIS, Appendix B of the draft EIS – CMR plan, and Appendix H of the draft EIS – Pipeline Construction in Sand Hills Native Rangelands for additional information). Specific construction, reclamation, and post-construction activities would be employed in the Sand Hills topographic region based on the recommendations of these experts. Keystone would incorporate these procedures into construction within the Sand Hills topographic region, for either the proposed Project route or any other alternative selected. With proper measures, risks of wind erosion during the time period when vegetation is being reestablished can be largely eliminated.
- The installation and operation of crude oil pipeline systems is a compatible land use in Nebraska under existing federal and state land use policies and regulations. Major pipelines currently

As a result of these findings, avoidance of the Sand Hills topographic region and NHPAQ system are not considered appropriate screening criteria for the identification of alternative routes. Also, Keystone has committed to provide replacement water if an accidental release from the proposed Project that is attributable to Keystone's actions contaminates groundwater used for drinking water or irrigation. Nonetheless, DOS considered one potential alternative (Western Alternative) that would avoid the Sand Hills topographic region and NHPAQ system entirely and four potential alternatives (Alternative SCS-A, Alternative SCS-A1A, Keystone Corridor Alternative, I-90 Corridor Alternative) that would reduce pipeline mileage crossing either the Sand Hills topographic region or the NHPAQ system. Two of the examined alternatives, the Keystone Corridor Alternative and the I-90 Corridor Alternative, were developed specifically in response to comments received on the draft EIS and the extensive public debate that has continued since that time. DOS has also considered concerns related to the Sand Hills topographic region and the NHPAQ system in its assessment of alternative routes that meet the four screening criteria for alternative routes.

Length of Alternative Routes Criterion

Within the constraints of the control point criteria, development of alternative routes considered minimizing the length of pipeline that would be required to reach the control points. As a general rule, construction of each mile of pipeline would impact approximately 13.3 acres, not including extra workspaces, access roads, construction yards, pipe yards, and rail yards. Operation of each mile of pipeline would affect approximately 6.0 acres. As a result, there usually are environmental advantages to keeping the length of pipe required to reach the control points as short as possible while considering all other issues of concern.

Distance Parallel to Existing Linear ROW Criterion

In determining potential route alternatives, the fourth criterion was to establish routes that would have all or part of their length parallel to existing linear facility ROWs. Routes were considered parallel to existing ROWs if they were overlapping, directly adjacent to, or within 150 feet of an existing ROW. The industry standard for new pipeline centerline separation from existing pipelines is 25 feet, a distance sufficient to provide room for maintenance and construction restrictions.

The rationale for siting a new pipeline parallel to an existing ROW is that concentrating linear facilities in or near existing linear corridors may reduce the impacts to resources that have not previously been disturbed by major linear project construction. Installation of a new pipeline along existing, cleared ROWs may be environmentally preferable to construction along new ROWs, and construction and operation effects and cumulative impacts can normally be reduced by the use of previously cleared ROWs. However, if the new pipeline is installed in a ROW that is not within the existing ROW, the impacts may be similar to those of new construction that is not parallel to an existing ROW. In addition, in some cases it may be advantageous to select a new pathway, depending on the number of miles of new construction that may be required to capitalize on existing development corridors and the specific effects of corridor expansion in areas with important human development, cultural resources, or environmental resources. For example, while a new corridor may contribute to habitat fragmentation in areas with currently uninterrupted species use areas, the lateral expansion of an existing corridor with a new ROW may exacerbate the problem along that linear corridor. This criterion addresses the concern of many

commenters that DOS should consider an alternative route paralleling the existing Keystone Oil Pipeline along all or part of its route.

4.3.2.2 Identification of Route Alternatives

The four criteria listed in Section 4.3.2.1 were used in the screening process to identify potential alternative routes to the proposed Project route within each segment. As described in Section 4.3.2, the routes were evaluated based on technical and economic practicability, and whether the or not the route alternative would meet the purpose of and need for the proposed Project. Alternatives that met those criteria were then evaluated to determine whether or not they offered an overall environmental advantage over the proposed route, particularly with regard to the avoidance criterion. Consistent with 40 CFR 1502.14, the reasons for eliminating alternative routes from further detailed study are provided for each potential alternative in the comparison of potential alternatives to the proposed route presented below. Additional information on the proposed Project route is presented in Sections 2.0 and 3.0.

4.3.3 Alternative Routes for the Steele City Segment

The Steele City Segment extends from the U.S./Canada border near Morgan, Montana to the northern end of the Cushing Extension near Steele City, Nebraska. For the Steele City Segment, the following potential route alternatives were considered:

- Express-Platte Alternative Routes (Section 4.3.3.1);
- Steele City Segment (SCS) Alternative A (Section 4.3.3.2);
- Alternative SCS-A1A (Section 4.3.3.3);
- Keystone Corridor Alternative (Section 4.3.3.4);
- I-90 Corridor Alternatives A and B (Section 4.3.3.5); and
- Baker Alternative (Section 4.3.3.6).

These alternative routes are depicted in Figures 4.3.3-1, 4.3.3-2, and 4.3.3-3.

As a cooperating agency, the MDEQ considered the alternative routes described below. However, to comply with the requirements of the state's MFSA, MDEQ also considered two other route alternatives in Montana as well as many minor route variations in Montana. The development and analysis of the MFSA-related alternatives and variations in Montana are described in Appendix I to the draft EIS and summarized in Section 4.3.7.

4.3.3.1 Express-Platte Alternatives

The Express-Platte Pipeline System is a 1,700-mile-long oil transportation network that connects Canadian and U.S. producers to refineries in the Rocky Mountain and Midwest regions of the U.S. The system consists of two crude oil pipelines – the Express Pipeline and the Platte Pipeline. The Express Pipeline extends from Hardisty, Alberta Canada to markets in Montana, Wyoming, Utah, and Colorado. It crosses the U.S./Canada border near the Port of Wild Horse, Montana and connects to the Platte Pipeline system at Casper, Wyoming. The Platte system extends from Casper to Wood River, Illinois.

At the request of MDEQ, Express-Platte Alternative 1 was developed to parallel the Express-Platte System from Hardisty to a point near the northern end of the Cushing Extension where it would require a short new pipeline to connect with the Cushing Extension. Although this alternative would not meet the

control point criterion of starting near Morgan, where the Canadian portion of the route ends, the alternative was compared to the proposed route at the request of MDEQ. In addition, Express-Platte Alternative 2 was developed to meet the control-point criterion; i.e., it would begin at the control point at Morgan. Both of these alternative routes would require construction of a new pipeline to connect the southern end of the Cushing Extension to the delivery points in Texas (Gulf Coast Segment). In the assessment of the two Express-Platte alternatives, it was assumed that the route of the Gulf Coast Segment would be the same as for the proposed Project.

The Express-Platte alternative routes are addressed below. The existing Express-Platte System and the two Express-Platte alternatives are depicted on Figure 4.3.3-1.

Express-Platte Alternative 1

The U.S. portion of Express-Platte Alternative 1 (i.e., the Steele City Segment of the alternative) would be approximately 1,049 miles long. The proposed Project route in this area (Alternative SCS-B) would be approximately 851 miles long. Express-Platte Alternative 1 would parallel the existing Express-Platte corridor through Montana, Wyoming, Nebraska, and Kansas before diverting to connect with the Cushing Extension at Steele City. In comparison, the proposed Project route would be parallel to about 30 miles of existing ROWs along its 851.6-mile length. Although Express-Platte Alternative 1 would parallel an existing pipeline corridor, the existing easements along that corridor are in the control of a different company and it may not be possible to construct the alternative pipeline within the existing ROW.

Comparisons of the impacts of Express-Platte Alternative 1 on key environmental resources with those of the proposed Project route are presented in Table 4.3.3-1. The alternative is about 234 miles longer than the proposed Project route and would affect about 3,200 more acres than the proposed Project route when considering the 110-foot-wide construction ROW, extra work spaces, additional contractor and pipe yards, and additional access roads over that distance. Express-Platte Alternative 1 would also affect more wetlands, developed land, forested lands, rangeland and grassland, agricultural land, and federal lands as compared to the proposed route. It would also cross more streams and rivers and would extend across approximately 439 miles of the NHPAQ system as opposed to the 247 miles of the proposed route that would extend over the aquifer (see Figure 4.3.3-2). The alternative would cross approximately 31.9 miles of the Sand Hills topographic region as compared to 68.1 miles for the proposed Project.

In comparison to the proposed route, Express-Platte Alternative 1 would cross fewer miles of the Sand Hills topographic region. However, it would be substantially longer, have a greater area of impact, affect more areas of key resources, and would extend over more land underlain by the NHPAQ system. Therefore, the Express-Platte Alternative 1 would not offer an overall environmental advantage over the proposed route and was eliminated from further consideration.

Additionally, Keystone has obtained the necessary permits to construct the proposed Project in Canada which terminates north of the U.S./Canada border near Morgan. Implementation of Express-Platte Alternative 1 would require submitting a new permit application to NEB for a revised route in Canada, and the approval process would not be completed in a time frame that would meet the proposed Project objectives. For the above reasons Express-Platte Alternative 1 was eliminated from further consideration.

Express-Platte Alternative 2

Express-Platte Alternative 2 was developed to provide an alternative route that would start at the control point near Morgan while still paralleling the existing pipeline system over much of its length. This alternative, which is depicted on Figure 4.3.3-1 and included in the impact comparisons in Table 4.3.3-1, would be approximately 1,085.5 miles long. It would not require a new route in Canada.

TABLE 4.3.3-1
Impact Comparisons for the Steele City Segment Alternatives

Characteristic	SCS-B (Proposed Route)	SCS-A	SCS-A1A	Express-Platte 1	Express-Platte 2	Keystone Corridor
Total Length (Miles)	851.6	923.2	954.6	1,049.2	1,085.5	1,102.2
Land Use (Acres)[a]						
Agricultural Land	2,974.6	7,264.5	7,617.6	5,240.6	4,434.2	10,360.5
Barren Land	6.3	8.6	10.5	66.1	81.7	1.5
Developed Land	174.2	363.8	363.2	432.6	400.7	521.6
Forested	33.0	89.6	89.9	93.1	140.5	171.1
Rangeland/Grassland	8,002.7	4,369.0	4,431.7	7,843.3	9,165.2	3,041.3
Wetlands	148.1	150.2	147.9	290.3	229.2	486.7
Open Water	15.8	63.6	67.2	23.3	21.8	113.3
Total	11,354.7	12,309.3	12,728.0	13,989.3	14,473.3	14,696.0
Federal Land Ownership (Acres)[b]						
Bureau Land Management	595.2	271.9	283.4	1,380.7	1957.3	331.7
Bureau of Reclamation	0.0	0.0	0.0	286.8	286.8	0.0
Department of Defense	0.0	16.2	16.2	0.0	0.0	0.0
Fish and Wildlife Service	0.0	0.0	2.9	0.0	0.0	0.0
Forest Service	0.0	97.5	97.5	0.0	0.0	0.0
National Park Service	0.0	18.9	18.9	0.0	0.0	18.9
Total	595.2	404.5	418.9	1,667.5	2,244.1	350.6
Fort Peck Indian Reservation (Acres)[c]	0.0	1,200.0	0.0	0.0	0.0	0.0
Number of Streams and Rivers crossed[d]	454	544	538	695	693	540

[a] Land use from U.S. Geological Survey (USGS) 2001. Acres calculated based on a 110-foot-wide ROW and the pipeline miles of each land use crossed.
[b] Federal lands from ESRI 2004a or National Park Service 2010a. Acres calculated based on a 110-foot-wide ROW and the pipeline miles of each land use crossed.
[c] Fort Peck Indian Reservation from ESRI 2004a. Acres calculated based on a 110-foot-wide ROW and the pipeline miles of each land use crossed.
[d] Streams and rivers from ESRI 2004b.

Comparisons of the impacts on key environmental resources of Express-Platte Alternative 2 with those of the proposed Project route are presented in Table 4.3.3-1. This alternative would be about 198 miles longer than the proposed route and would affect about 2,700 more acres when considering the construction ROW, extra work spaces, additional contractor and pipe yards, and additional access roads over that distance. In addition, it would cross the Antelope Creek Wilderness Study Area from MP 112.7 to MP 114.9. BLM manages wilderness study areas under the National Landscape Conservation System to protect their value as wilderness until Congress decides whether or not to designate them as wilderness. On the north side of the Missouri River, 9,600 acres of this 12,350-acre wilderness study area were recommended for full wilderness designation. The area has many opportunities for solitude and recreation such as hiking, hunting, rock climbing, and photography.

Although in comparison to the proposed route, Express-Platte Alternative 2 would cross fewer miles of the Sand Hills topographic region, it would be substantially longer, have a greater area of impact, affect more areas of key resources, and would extend over more of the NHPAQ system. It would also cross a National Wilderness Study Area that has been recommended for full wilderness status. As a result, Express-Platte Alternative 2 would not offer an overall environmental advantage over the proposed route and was eliminated from further consideration.

4.3.3.2 Steele City Segment Alternative A (SCS-A)

Alternative SCS-A would parallel the existing Northern Border Pipeline ROW in its northernmost section for approximately 555 miles. It would then intersect and parallel the ROW of the existing Keystone Oil Pipeline for approximately 368 miles until reaching the control point at the northern end of the Cushing Extension. In comparison, the proposed Project route would parallel about 30 miles of existing ROWs along its 851.6-mile length. Alternative SCS-A would cross parts of Montana, North Dakota, South Dakota, and Nebraska. It would also cross 90 miles of the Fort Peck Indian Reservation in Montana, affecting approximately 1,200 acres of the reservation when considering the 110-foot-wide construction ROW, extra work spaces, additional contractor and pipe yards, and additional access roads over that distance.

In Montana, Alternative SCS-A would cross the BLM-managed Bitter Creek Wilderness Study Area, an area designated under the Federal Land Policy and Management Act as having wilderness characteristics consistent with the provisions of the Wilderness Act of 1964. In North Dakota, Alternative SCS-A would cross the Little Missouri National Grassland managed by the USFS. It would also cross the Missouri River along the South Dakota-Nebraska border and the Missouri River National Recreational Area administered by the NPS. However, it would avoid a crossing of the Yellowstone River.

Comparisons of the potential impacts on key environmental resources of Alternative SCS-A to those of the proposed route are presented in Table 4.3.3-1. SCS-A would cross substantially more agricultural and developed land, more wetlands, more forested land, and approximately 110 more streams and rivers than the proposed Project route. It would cross substantially less rangeland and grass land than the proposed route.

Alternative SCS-A would cross approximately 2.4 miles of the Sand Hills topographic region, whereas the proposed route would cross approximately 68.1 miles of the Sand Hills topographic region. However, the proposed Project route in the Sand Hills topographic region was selected to reduce erosion problems to the extent practicable, although some minor route re-alignments may be required during construction to avoid particularly erosion-prone locations such as ridge tops and existing blow-out areas (see CMR plan, Appendix B of the draft EIS). During the proposed Project design effort, local NRCS offices and regional experts on Sand Hills reclamation from the University of Nebraska, University of South Dakota, and Nebraska Department of Roads were consulted and their recommendations on routing, construction

techniques, and restoration techniques to minimize potential damage to Sand Hills vegetation were incorporated into the proposed Project plan (see Section 3.2.2.1, Appendix B of the draft EIS – CMR plan, Appendix H of the draft EIS – Pipeline Construction in Sand Hills Native Rangelands, and Appendix D of the SDEIS – Sand Hills Construction/Reclamation Unit, for additional information). Specific construction, reclamation, and post-construction activities would be employed in the Sand Hills based on the recommendations of these experts. Keystone would incorporate these procedures into construction within the Sand Hills topographic region, for either the proposed Project route or Alternative SCS-A.

Alternative SCS-A would extend across approximately 145 miles of the NHPAQ system in comparison to the 247 miles of the proposed Project route that would extend over the aquifer (see Figure 4.3.3-2). The proposed Project route would be constructed and operated across the aquifer using standard PHMSA regulatory requirements for pipeline construction and operation in 49 CFR 195 as well as a set of even more stringent Project-specific Special Conditions developed by PHMSA and agreed to by Keystone. Standard PHMSA requirements are described in greater detail in Sections 2.3 and 3.13.1 as are the 57 Project-specific Special Conditions developed by PHMSA that are also provided in Appendix C of this SDEIS. In aggregate, these procedures would substantially reduce the potential risk of an accidental oil release from the pipeline anywhere along the proposed Project corridor. Based on the most recent PHMSA data for incidents associated with hazardous liquid pipelines (see Section 3.13.3.2), there is a statistical probability of 0.0007 incidents per mile of pipeline per year. These incident statistics include all releases from pipelines of all ages and are therefore conservative when compared to the potential risks from new pipelines designed consistent with current regulations, industry standards, and with the 57 Project-specific Special Conditions developed by PHMSA that would apply to the proposed Project. The majority of pipeline releases are small as further discussed in Section 3.13.

In summary, although the proposed Project route would cross more of the Sand Hills topographic region and overlie more of the NHPAQ system than would Alternative SCS-A, Alternative SCS-A would be approximately 72 miles longer than the proposed route and would affect at least 1,000 more acres than the proposed route when including the 110-foot-ROW, extra work space areas along the ROW, additional pipe and construction yards, and additional access roads. It would also impact more than twice as many acres of agricultural land, developed land, and forested land. Alternative SCS-A would cross more open water, substantially more streams and rivers, and slightly more wetlands than the proposed route. It would also cross tribal lands, wilderness areas managed by BLM, grasslands managed by USFS, and a major recreational area under the jurisdiction of NPS. Therefore, route Alternative SCS-A would not offer an overall environmental advantage over the proposed route and was eliminated from further consideration.

4.3.3.3 Steele City Segment Alternative A1A

Except for a short distance along the northern portion of Alternative SCS-A1A, this route is the same as that of Alternative SCS-A (see Figure 4.3.3-1). Alternative SCS-A1A deviates from Alternative SCS-A to avoid affecting lands within the Fort Peck Indian Reservation in Montana. The deviation would begin in central Valley County, Montana and extend to the east along a path that would be north of the reservation. It would then turn south to pass to the east of the reservation in Sheridan County until crossing into Roosevelt County, Montana where it would extend to the southeast and cross into Williams County, North Dakota. From there, Alternative SCS-A1A would follow the same route as Alternative SCS-A to reach the control point at the northern end of the Cushing Extension.

Alternative SCS-A1A would cross Diversion Ditch No. 1 in the Medicine Lake National Wildlife Refuge (NWR), a canal that connects the refuge to Big Muddy Creek in Sheridan County and prairie potholes east of the Fort Peck Indian Reservation. Medicine Lake NWR is a 31,660-acre refuge established to

provide breeding habitat for migratory birds and other wildlife. Prairie potholes are present in northeastern Montana and North Dakota. These are depressional wetlands (primarily freshwater marshes) that are either permanent or temporary potholes that provide breeding areas and habitat for migratory birds and help prevent downstream flooding. These sensitive habitats are more prominent in the eastern portion of Alternative SCS-A1A than other Steele City Segment alternatives.

Comparisons of the potential impacts on key environmental resources of Alternative SCS-A1A to those of the proposed Project route are presented in Table 4.3.3-1. Alternative SCS-A1A would cross substantially more agricultural and developed land, more forested land, and 84 more streams and rivers than the proposed route. However, the alternative would cross substantially less rangeland and grass land than the proposed route. Alternative SCS-A1A would be approximately 103 miles longer than the proposed Project route and would affect at least 1,400 more acres when including the 110-foot-wide construction ROW, extra work space areas, additional pipe and construction yards, and additional access roads. Alternative SCS-A1A would have the same route as Alternative SCS-A across the Sand Hills topographic region and the NHPAQ system.

In summary, the impacts to key environmental resources associated with Alternative SCS-A1A, including impacts to BLM-managed Bitter Creek Wilderness Study Area, the Little Missouri National Grassland managed by the USFS, and the Missouri River National Recreational Area administered by the NPS are similar to those of Alternative SCS-A. However, Alternative SCS-A1A would also cross the Medicine Lake NWR and would affect the environmentally sensitive prairie pothole areas. Therefore, as with Alternative SCS-A, Alternative SCS-A1A would not offer an overall environmental advantage over the proposed route and was eliminated from further consideration.

4.3.3.4 Keystone Corridor Alternative

Several commenters requested that Keystone follow a route that would parallel the entire existing Keystone Oil Pipeline. Many commenters also recommended that the existing Keystone route be used to reduce the distance of pipeline overlying the Sand Hills topographic region of Nebraska and the NHPAQ system, which includes the Ogallala aquifer.

For the reasons presented below, this potential alternative was eliminated from consideration. In particular, this alternative was identified largely in response to comments received about concerns over the risk of spills to the NHPAQ system. As illustrated in Figures 3.3.1-1 through 3.3.1-3 and Figure 4.3.3-6, which show all water wells within 1 mile of the proposed pipeline route, the alternative would not eliminate risk to the aquifer, but would simply transfer it to other parts of the aquifer system that are more heavily used and that also include areas of shallow groundwater. The alternative would also increase the risk of spill in rivers and streams by significantly increasing the number of rivers and streams crossed.

Although Alternatives SCS-A and SCS-A1A would parallel the existing Keystone Pipeline ROW for about 368 miles, in response to comments on the draft EIS, DOS also considered an alternative that would begin at the Morgan control point and extend approximately 442 miles eastward into eastern North Dakota (see Figure 4.3.3-1). That portion of the alternative was routed to avoid major national wildlife refuges and several smaller refuges that are present near the northern border of North Dakota. The route also avoids crossing the Turtle Mountain Indian Reservation. In North Dakota the alternative route intersects the existing Keystone Pipeline ROW and extends southward about 640 miles, paralleling the existing Keystone Pipeline ROW to the control point at the northern end of the Cushing Extension. This alternative would require inclusion of a new pipeline from the southern end of the Cushing Extension to delivery points in PADD III. In this analysis, it has been assumed that the route of the Gulf Coast Segment and the Houston Lateral of the proposed Project would be included in the Keystone Corridor Alternative and that the impacts of construction, operation, and maintenance of those portions of the

alternative would result in impacts that would be identical to those identified in Section 3.0 of the draft EIS, as supplemented by the information provided in Section 3.0 of this SDEIS.

The Keystone Corridor Alternative is approximately 251 miles longer than the proposed Project route. It is parallel to approximately 640 miles of the existing Keystone Pipeline ROW. In comparison, the proposed Project route is parallel to about 30 miles of existing ROWs along the Steele City Segment. As noted in the discussion of the criterion regarding use of existing ROWs in Section 4.3.2.1, installation of a new pipeline along existing, previously cleared and maintained ROWs may be environmentally preferable to construction along new ROWs, and construction and operation effects and cumulative impacts can normally be reduced by the use of previously cleared ROWs. However, if a pipeline is installed in a ROW that is not within the existing ROW, the impacts may be similar to those of new construction that is not parallel to an existing ROW. It is possible that the route of the Keystone Corridor Alternative could be included within part of the existing Keystone Oil Pipeline permanent ROW along some of the route since Keystone would be the owner of both pipelines. However, it is also likely that a 25-foot separation between pipelines would be required for safety. This would result in the alternative pipeline being installed no closer than at about the edge of the existing 50-foot-wide permanent ROW (25 feet on each side of the existing pipeline) except in areas where there are constraints outside of and adjacent to the existing ROW. In those areas the route would have to be aligned to be as close to the existing ROW as possible but would not be adjacent to it. In addition, to avoid damage to the existing pipeline, construction equipment and most construction activities would be limited to one side of that pipeline. Therefore, construction of the Keystone Corridor Alternative would require an area outside of the permanent ROW of the existing Keystone Oil Pipeline to accommodate the construction equipment and activities. This area would also extend beyond the previously disturbed construction ROW of the existing Keystone Oil Pipeline since the edge of that construction ROW was typically about 55 feet from the center of the pipeline. In addition, the portion of the construction ROW of the existing pipeline that is outside of the permanent ROW (i.e., the area typically 30 feet from the edge of the permanent ROW) has been reclaimed and would be cleared and disturbed again if the Keystone Corridor Alternative were constructed, thus negatively affecting ROW restoration already implemented or ongoing along these corridors.

It is likely that construction of the Keystone Corridor Alternative would require a construction ROW that is approximately the same width as the construction ROW of the proposed Project. Therefore, for comparison purposes, it was assumed that the Keystone Corridor Alternative would have a construction ROW that would extend 110 feet from the existing pipeline and that there would be only minor disturbances to the existing permanent ROW between the edge of that ROW and the existing pipeline. The portion of the route between Morgan, Montana and the existing pipeline would also require a 110-foot-wide construction ROW. In addition, construction of the alternative would require land for pipe rail yards, pipe storage yards, construction yards, temporary access roads, and in the portion of the route between Morgan and the existing pipeline, construction camps would likely be required to house the workforce. That area is remote and there is little transient housing available.

As a result, construction of the Keystone Corridor Alternative between Morgan and the existing Keystone ROW and along the area adjacent to the existing 640-mile-long ROW would affect an area that would be at least 3,400 acres larger than the area affected by construction of the proposed Project. In addition, it has been assumed that construction of a pipeline to reach Gulf Coast markets would affect the same size area as the proposed Project.

The route of the Keystone Corridor Alternative through Nebraska would be identical to that of Alternatives SCS-A and SCS-A1A (see Figure 4.3.3-1). The Keystone Corridor Alternative extends across approximately 145 miles of the NHPAQ system, which includes the Ogallala aquifer, in comparison to the 247 miles of the proposed Project route that would extend over the NHPAQ system

(see Figure 4.3.3-2). The Keystone Corridor Alternative crosses approximately 2.4 miles of the Sand Hills topographic region, whereas the proposed route crosses approximately 68.1 miles of the Sand Hills topographic region.

As can be seen in Figure 4.3.3-3, the Keystone Corridor Alternative would cross numerous heavily used aquifers. While it would avoid most of the Sand Hills topographic region, it would cross much more highly utilized aquifers than the shallow aquifers underlying the Sand Hills topographic region. The proposed Project would be constructed and operated across the aquifer using standard PHMSA regulatory requirements for pipeline construction and operation in 49 CFR 195 as well as a set of 57 more stringent Project-specific Special Conditions developed by PHMSA and agreed to by Keystone. Standard PHMSA requirements are described in greater detail in Sections 2.3 and 3.13.1 as are the 57 Project-specific Special Conditions developed by PHMSA that are also provided in Appendix C of this SDEIS. Incorporation of those conditions would result in a project that would have a degree of safety over any other typically constructed domestic oil pipeline system under current code and a degree of safety along the entire length of the pipeline system similar to that which is required in HCAs as defined in 49 CFR 195.450. If the Keystone Corridor Alternative were to be constructed, the 57 Project-specific Special Conditions would also be incorporated into project construction, operation, and maintenance.

Based on the most recent PHMSA data for incidents associated with hazardous liquid pipelines (see Section 3.13.3.2), there is a statistical probability of 0.0007 incidents per mile of pipeline per year. These incident statistics include all releases from pipelines of all ages and are therefore conservative when compared to the potential risk from new pipelines designed consistent with current regulations and industry standards. The majority of pipeline releases are small as further discussed in Section 3.13. Additionally, no existing pipelines have been constructed and operated in compliance with the Project-specific Special Conditions that would apply to the proposed Project. Further, the proposed Project route in the Sand Hills topographic region was selected to reduce erosion problems to the extent practicable, although some minor route re-alignments may be required during construction to avoid particularly erosion-prone locations such as ridge tops and existing blow-out areas (see the CMR plan in Appendix B of the draft EIS). During the design of the proposed Project, local NRCS offices and regional experts on Sand Hills reclamation from the University of Nebraska, University of South Dakota, and Nebraska Department of Roads were consulted and their recommendations on routing, construction techniques, and restoration techniques to minimize potential damage to Sand Hills vegetation were incorporated into the proposed Project plan (see Section 3.2 and Appendix D of this SDEIS, and Appendices B and H of the draft EIS for additional information). Specific construction, reclamation, and post-construction activities would be employed in the Sand Hills topographic region based on the recommendations of these experts. Keystone would incorporate these procedures into construction within the Sand Hills topographic region, for either the proposed Project route or the Keystone Corridor Alternative.

A comparison of potential impacts to key environmental resources of the Keystone Corridor Alternative to those of the proposed Project route is presented in Table 4.3.3-1. This table does not include impacts associated with the Gulf Coast Segment or the Houston Lateral since those routes have been assumed to be the same for both the proposed Project and the Keystone Corridor Alternative.

The proposed Project route would affect about 2.6 times more rangeland and grassland than the Keystone Corridor Alternative, or approximately 4,961 more acres. This would represent an increase in the potential for impacts to rangeland and grassland soils, lost grazing areas and grazing time, and other short- to long-term impacts to those areas as compared to the alternative. It would also increase the amount of compensation that Keystone would be required to provide for lost grazing opportunities and other damages. However, the Keystone Corridor Alternative would affect about 3.5 times more agricultural land than the proposed Project route, or about 7,385 more acres. This would result in

increasing the potential for short- to long-term impacts to soil, crop production, and other damages to agricultural land as compared to the impacts of the proposed Project.

The alternative route would affect almost 3 times more acres of developed land than the proposed Project route. Impacts in developed land would be associated primarily with construction, although it is possible that pump stations and MLVs could be in the vicinity of the developed areas and would affect visual quality and create noise impacts during operation. However, there has not been a hydraulic design of the Keystone Corridor Alternative and it is not possible to identify the locations of pump stations or MLVs along the alternative route.

The alternative route would affect about 3.3 times more wetland area than the proposed Project route, or about 339 more acres. This is a substantially greater area of wetland, although mitigation measures would be implemented to avoid or minimize the impacts to wetlands, and for jurisdictional wetlands, compensatory mitigation would likely be required as part of the USACE Section 404 permitting process.

The Keystone Corridor Alternative would affect approximately 5 times more forested area, or about 138 more acres. That is a substantially greater area of forest impact than that of the proposed Project and could affect visual resources, wildlife habitat, and habitat fragmentation.

In summary, the Keystone Corridor alternative would not reduce the statistical risk of an accidental release from the proposed Project. Selecting the Keystone Corridor Alternative would simply transfer that same risk to other shallow groundwater aquifers, including other shallow aquifers within Nebraska. It would also actually represent an incremental increase in the risk that a spill would occur somewhere along the length of the pipeline, because spill risk is a function of pipeline length, and the Keystone Corridor Alternative is 251 miles longer than the proposed route. The alternative would also affect a substantially greater total area than the proposed Project route, including crossing a river in the National Wild and Scenic River system, whereas the proposed Project route would not.

As a result of these considerations, the screening analysis indicated that the Keystone Corridor Alternative did not offer an advantage regarding the relative potential impacts to the NHPAQ system, nor did it offer an environmental advantage over the proposed Project route and it was therefore eliminated from further consideration.

4.3.3.5 I-90 Corridor Alternatives A and B

The I-90 Corridor Alternatives A and B were also developed as alternatives that would reduce the length of pipeline over the Sand Hills topographic region and the NHPAQ aquifer system, which includes the Ogallala aquifer. For the reasons presented below, this potential alternative was eliminated from detailed consideration. In particular, similar to the Keystone Corridor Alternative, this alternative was identified largely in response to comments received expressing concerns regarding the risk of spills to the NHPAQ system. The alternative would not eliminate risk to the aquifer, but as indicated in Figure 4.3.3-6 depicting water wells within 1 mile of the proposed alternative pipeline routes, it would simply transfer it to other parts of the aquifer system that are more heavily used and that still include areas of shallow groundwater, including areas of shallow groundwater in Nebraska. Also, this alternative is not consistent with the screening criterion of avoiding major water bodies since it would have to cross Lake Francis Case in South Dakota. The crossing of that reservoir using the HDD method may not be technically possible because of the distance involved as further discussed below. Finally, the alternative would increase the risk of a spill occurring in rivers and streams by increasing the number of rivers and streams crossed.

The I-90 Corridor Alternatives cross approximately 2.4 miles of the Sand Hills topographic region and about 145 miles of the NHPAQ system. In comparison, the proposed Project route would cross approximately 68.1 miles of the Sand Hills topographic region and 247 miles of the NHPAQ system. The alternatives were developed to parallel I-90 or other existing ROWs to the extent possible to minimize new corridor development while avoiding to the extent practicable crossings of either the Sand Hills topographic region or the NHPAQ system.

The I-90 Corridor Alternatives divert from the proposed Project route after crossing under I-90 in Nebraska and extend roughly eastward along the south side of I-90 to a point approximately 2 miles west of Alexandria, South Dakota. At that location, the Burlington Northern and Santa Fe (BNSF) railroad line diverts from the I-90 corridor and extends to the southeast parallel to State Highway 262 for approximately 16 miles. The I-90 Corridor Alternatives parallel the railroad/262 corridor to a point east of Emery, South Dakota where they intersect the existing Keystone Mainline ROW. From there, the alternative routes parallel the existing Keystone Mainline ROW to the existing Cushing Extension (see Figure 4.3.3-1 and Figure 4.3.3-4).

The pipeline for the I-90 Corridor Alternatives would not be installed within the existing highway ROW since the South Dakota Department of Transportation does not allow pipelines to be installed laterally within the I-90 ROW, although it does allow pipelines to cross the I-90 ROW. These alternatives would therefore require the development of new ROW in undisturbed land to the south of the existing highway ROW. The pipeline would not be installed within the BNSF railroad ROW but would be parallel to the ROW and would require the development of new ROW in undisturbed land near the existing railroad ROW.

The I-90 Corridor Alternatives would require two more crossings of the Missouri River than the proposed Project route, and these crossings would be within environmentally sensitive areas. One of these crossings would be at Lake Francis Case, a reservoir along the Missouri River formed by Fort Randall Dam. This dam is approximately 90 miles downstream of the potential crossing sites. Given the sensitivity of the crossing area, two variations of the I-90 Corridor Alternatives (A and B) were considered. I-90 Corridor Alternative A is parallel to I-90 through the Oacoma area and crosses Lake Francis Case adjacent to I-90. I-90 Corridor Alternative B parallels the South Dakota Highway 16/South Dakota Highway 50 alignment through the Oacoma area and across Lake Francis Case (see Figure 4.3.3-5). I-90 Corridor Alternative A avoids the downtown area of Chamberlain but requires crossing a steep bluff on the east side of the lake. I-90 Corridor Alternative B extends through the downtown area of Chamberlain but avoids the steeper portions of the bluff.

The two crossing sites are approximately 5,200 and 5,800 feet long and would likely involve the use of the HDD method if geotechnical considerations are appropriate. However, for large-diameter pipelines, the HDD method is limited to a distance of approximately 6,000 feet. When considering the onshore distance from the drill site to the exit hole, the height of the bluff, and the depth of the hole that would be bored, the aggregate distance may be too great for the HDD method. More detailed engineering studies would be required to determine whether or not the HDD method would be feasible for this crossing, assuming that geotechnical conditions were suitable for HDD. If the HDD method is not suitable, a wet-cut crossing method using barges and bottom dredging would likely be required.

Lake Francis Case extends about 107 miles from the Fort Randall Dam to the Big Bend Dam, which is about 20 river miles north of the I-90 crossing of Lake Francis Case. Approximately 1 million people use the 19 recreation areas along the lake each year (USACE 2010). Recreational opportunities include boating, fishing, swimming, hunting (outside of recreational areas), geocaching, camping, and picnicking. Construction of the alternative route through this area on both sides of the reservoir would disrupt recreational traffic and recreational activities for the duration of the construction period in that area.

Clearing the ROW would result in changes to the composition and structure of vegetation, including forested areas. This would result in changes to the visual character and may be considered adverse impacts to those using the area for recreation. It would also alter the habitats supporting species that are hunted. In addition, both crossing variations and the ROW of the alternatives are in the vicinity of historic American Island and other areas associated with the Lewis and Clark expedition. If the HDD installation method is used, the pipeline would be installed substantially below the bottom of the reservoir to minimize the potential for outside forces (e.g., anchor drag) that could cause an accidental release of crude oil from the portion of the pipeline under the lake during operation. However, the potential for such releases from the onshore portions of the pipeline adjacent to the crossing would be the same as for those within other terrestrial areas where the pipeline is buried.

As noted in Table 3.13.5-10 (Typical Ranges of Potential Crude Oil Spill Environmental Impacts), the potential impacts of crude oil reaching large rivers ranges from negligible to minor for very small spills (less than 210 gallons [5 barrels]), but can be major to catastrophic[28] for very large spills (greater than 210,000 gallons [5,000 barrels]). In comparison, the potential impacts of spills reaching groundwater range from negligible for very small spills to substantive[29] for very large spills. As a result, implementation of the I-90 Corridor Alternatives to avoid a portion of the NHPAQ system would serve to transfer the risk of a spill to Lake Francis Case where the potential impact of a spill would likely be greater than that of a spill over the NHPAQ system (see Sections 3.3 and 3.13 for additional information on the potential impacts of a crude oil spill from the proposed Project over the NHPAQ system and the cleanup methods involved). Additionally, along terrestrial portions of the I-90 Corridor Alternatives, groundwater use is much more extensive than is groundwater use across the Sand Hills topographic region (see Figure 4.3.3-6). Therefore, the risk of a spill that could affect groundwater would be transferred from an area with less ongoing groundwater usage to areas with extensive ongoing groundwater usage in these terrestrial areas.

The second crossing of the Missouri River would be near Yankton, South Dakota either within the existing Keystone ROW or more likely adjacent to that crossing. The crossing area is within the Missouri National Recreational River, a 98-mile-long portion of the river administered by the National Park Service that extends from Ponca, South Dakota on the southeast end to the Fort Randall Dam on the northwest end. As noted above, the Missouri National Recreational River was established by Congress to protect the natural, cultural, and recreational resources of two remaining free-flowing segments of the Missouri River in as natural a state as possible and to keep them available for the public. The second

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[28] **Major Impact –** Patchy to continuous and heavy presence of oil on terrestrial and aquatic habitats near the spill site and for substantive distances down gradient from the spill site. Impacts may be present for weeks to months and potentially for a year or more. The impacted area may include many acres to sections of land or wetlands, and several miles of riverine habitat. There may be effects on the local biological community and population-level impacts on organisms and habitats, as well as disruption of human uses in local oiled areas. There may be substantive effects on HCAs including USAs.

Catastrophic Impact – Mostly continuous or nearly continuous presence of oil on all habitats near and/or for substantive distances down gradient of the spill site. Impacts may be present for months to years. The impacted area may include many acres to sections of land or wetlands, and several to numerous miles of river or other aquatic habitat. There may be both local and regional disruption of human uses. There may be both local and regional impacts to biological populations and communities. There may be significant to catastrophic effects on HCAs including USAs.

[29] **Substantive Impact –** Patchy to continuous presence of oil on terrestrial and aquatic habitats near the spill site. Impacts may be present for weeks to a few months and affect tens of acres or a few miles of stream/river habitat. There may be impacts to the local biological community and population-level effects on organisms and human uses of the area. There may be detectable effects on HCAs including USAs.

Missouri River crossing would likely be accomplished using the HDD method, the same installation method used for the existing Keystone Mainline pipeline, to minimize construction impacts. As described above, there is a potential for major to catastrophic impacts due to a very large crude oil spill from the proposed Project if it reaches the river. The potential impact of such a spill is likely greater than that of a very large crude oil spill reaching groundwater in the NHPAQ system. As a result, avoiding a portion of the NHPAQ system by implementing either of the I-90 Corridor Alternatives would serve to transfer a portion of the spill risk to the Missouri National Recreational River area where the potential impact of a spill would likely be greater than that of a spill over the NHPAQ system (see Sections 3.3 and 3.13 for additional information on the potential impacts of a crude oil spill from the proposed Project over the NHPAQ system and the cleanup methods involved).

Although other shorter potential routes through undeveloped land south of I-90 could be considered, they would likely have to cross either an extension of the NHPAQ system before meeting the existing Keystone ROW or cross the Niobrara River, Niobrara State Park, and/or the Santee Sioux Indian Reservation. A route in that general area would also be in the watershed of and parallel to a portion of the Missouri River that is designated as the Missouri National Recreational River and is included in the National Wild and Scenic Rivers System. The Missouri National Recreational River was established by Congress to protect the natural, cultural, and recreational resources of two remaining free-flowing segments of the Missouri River in as natural a state as possible and to keep them available for the public. The goal is to preserve, protect, interpret, restore, and enhance the natural and cultural resources of those segments of the river for the enjoyment of present and future generations.

The proposed Project would be constructed and operated across the aquifer using standard PHMSA regulatory requirements for pipeline construction and operation in 49 CFR 195 as well as a set of 57 more stringent Project-specific Special Conditions developed by PHMSA and agreed to by Keystone. Standard PHMSA requirements are described in greater detail in Sections 2.3 and 3.13.1 as are the 57 Project-specific Special Conditions developed by PHMSA that are also provided in Appendix C of this SDEIS. Incorporation of those conditions would result in a project that would have a degree of safety over any other typically constructed domestic oil pipeline system under current code and a degree of safety along the entire length of the pipeline system similar to that which is required in High Consequence Areas (HCAs) as defined in 49 CFR 195.450. If either of the I-90 Corridor Alternatives were to be constructed, the 57 Special Conditions would be incorporated in construction, operation, and maintenance along that route.

Based on the most recent PHMSA data for incidents associated with hazardous liquid pipelines (see Section 3.13.3.2), there is a statistical probability of 0.0007 incidents per mile of pipeline per year. These incident statistics include all releases from pipelines of all ages and are therefore conservative when compared to the potential risk from new pipelines designed consistent with current regulations and industry standards. The majority of pipeline releases are small as further discussed in Section 3.13. Additionally, no existing pipelines have been constructed and operated in compliance with the Project-specific Special Conditions that would apply to the proposed Project.

The Keystone Corridor Alternative would cross 86 more streams and rivers than the proposed Project. Although HDD would be used to cross major streams, many of the additional crossings would be constructed using one of the open cut methods described in Section 2.3. As compared to the proposed Project route, this increase in the number of stream crossings represents an increase in the potential for impacts to water quality, fisheries resources, and the habitats that support those resources.

Additionally, comments received in 2007 on the draft EIS for the Keystone Oil Pipeline Project are informative relative to the likelihood of public acceptance of a second pipeline paralleling that project. Specific concerns were expressed at that time from residents of North Dakota, South Dakota, and

Nebraska relative to the possibility of future pipelines following the Keystone pipeline route. Commenters from North Dakota expressed concern about the project's effect on water supplies, including the water supplies for Fargo, North Dakota and the potential for contamination of the Sheyenne River drainage. Contamination of that drainage could lead to transboundary impacts to Lake Winnipeg and the Hudson River drainage in Canada, as well as potential contamination of shallow aquifers. Commenters from South Dakota were concerned about impacts of the Keystone Oil Pipeline Project crossing of the Missouri River, especially through a National Wild and Scenic River reach. The Keystone Corridor Alternative would cross the Missouri River in the same reach. Additional concerns were related to rural water supply impacts, including the WEB, Clark, Hanson, Turner McCook, Lewis and Clark, and B-Y water systems.

Concerns raised in 2007 by commenters from Nebraska included the project route through Seward, Nebraska and potential impacts to the Seward water system. In all three states, the presence of shallow groundwater aquifers beneath the Keystone route was a concern, including concerns about potential impacts to the NHPAQ system, which includes the Ogallala aquifer. In essence, the Keystone Corridor Alternative, while reducing the distance over the shallow groundwater of the Sand Hills Unit of the NHPAQ system and other portions of the NHPAQ system, does not eliminate the risk to areas of shallow groundwater, rather it would transfer any spill risks to shallow aquifers in other regions, including other shallow aquifers within Nebraska.

Further, the proposed Project route in the Sand Hills topographic region was selected to reduce erosion problems to the extent practicable, although some minor route re-alignments may be required during construction to avoid particularly erosion-prone locations such as ridge tops and existing blow-out areas (see the CMR plan in Appendix B of the draft EIS. During the proposed Project design effort, local NRCS offices and regional experts on Sand Hills reclamation from the University of Nebraska, University of South Dakota, and Nebraska Department of Roads were consulted and their recommendations on routing, construction techniques, and restoration techniques to minimize potential damage to Sand Hills vegetation were incorporated into the proposed Project plan (see Section 3.2 and Appendix D of this SDEIS, and Appendices B and H of the draft EIS for additional information). Specific construction, reclamation, and post-construction activities would be employed in the Sand Hills topographic region based on the recommendations of these experts. Keystone would incorporate these procedures into construction within the Sand Hills topographic region, for either the proposed Project route or the I-90 Corridor Alternatives.

A comparison of the impacts on key environmental resources of the I-90 Corridor Alternatives to those of the proposed Project route is provided in Table 4.3.3-2. The I-90 Corridor Alternatives would be approximately 70 miles longer than the proposed Project route and would affect at least 1,000 more acres during construction than the proposed Project route, including the 110-foot-wide construction ROW, extra work space areas, additional pipe and construction yards, and additional access roads.

The I-90 Corridor Alternatives would parallel approximately 144.5 miles of I-90 or I-90 and state highways 16 and 50, about 12.1 miles of state highway 262 and the BNSF ROW, and about 246.4 miles of the existing Keystone ROW. In comparison, the proposed Project route would parallel about 30 miles of existing ROWs. As noted in the discussion of the criterion regarding use of existing ROWs in Section 4.3.2.1, installation of a new pipeline along existing, cleared ROWs may be environmentally preferable to construction along new ROWs, and construction and operation effects and cumulative impacts can normally be reduced by the use of previously cleared ROWs. However, if the new pipeline is installed in a ROW that is not within the existing ROW, the impacts may be similar to those of new construction that is not parallel to an existing ROW. In this case, the I-90 Corridor Alternatives would be installed outside of the existing ROW. As with the Keystone Corridor Alternative, a portion of the I-90 Corridor Alternatives parallels the newly constructed Keystone Mainline. In this area, construction of either I-90

Corridor Alternative would likely impact previously implemented or ongoing restoration activities along that corridor.

The proposed Project route would affect almost 5 times more rangeland and grassland than the I-90 Corridor Alternatives, or about 1,956 more acres. This would represent an increase in the potential for impacts to rangeland and grassland soils, lost grazing areas and grazing time, and other short- to long-term impacts to those areas as compared to the alternatives. It would also increase the amount of compensation that Keystone would be required to provide for lost grazing opportunities and other damages. The alternative route would affect about 1.5 times more agricultural land than the proposed Project route, or about 835 more acres. This would result in increasing the potential for short- to long-term impacts to soil, crop production, and other damages to agricultural land as compared to the impacts of the proposed Project.

TABLE 4.3.3-2
Impact Comparisons of the I-90 Corridor Alternatives and the Associated Segment of the Route

Characteristic	Proposed Route	I-90 Corridor Alternatives
Total Length (Miles)	333.0	403.1 / 404.5[e]
Northern High Plains Aquifer System Crossed (Miles)[a]	247.2	144.9
Land Cover (Acres)[b]		
Agricultural Land	1,698.3	2,533.7
Developed Land	96.6	2,202.1
Forested	21.5	38.4
Rangeland/Grassland	2,521.3	564.7
Wetlands	92.0	21.9
Open Water	10.3	13.9
Total	4,440.0	5,374.7
Federal Land Ownership (Acres)[c]		
National Park Service (Missouri National Recreation Area)	0.0	26.4
U.S. Army Corps of Engineers (Lake Francis Case)	0.0	13.0 / 15.0[e]
Number of Stream Crossings[d]		
Perennial	22	25
Intermittent	157	200
Total	179	225

[a] Northern High Plains Aquifer from U.S. Geological Survey Water Resources Program.
[b] Land Cover from USGS 2001. Acres calculated based on a 110-foot-wide ROW and the pipeline miles of each land use crossed.
[c] Federal lands from ESRI 2004a or National Park Service 2010a. Acres calculated based on a 110-foot-wide ROW and the pipeline miles of each land use crossed.
[d] Streams and rivers from ESRI 2004b.
[e] I-90 Corridor Alternative B.

The I-90 Corridor Alternatives would cross 46 more streams and rivers than the proposed Project. Although HDD would be used to cross the major streams, about 43 of the additional crossings would be constructed using one of the wet open cut methods described in Section 2.3. As compared to the proposed Project route, this increase in the number of stream crossings represents a substantial increase in the potential for impacts to water quality, fisheries resources and the habitats that support the fisheries.

The proposed Project would affect approximately 70 acres more wetlands than the I-90 Corridor alternatives (92 acres and 21.9 acres respectively) based on data in the National Land Cover Dataset (USGS 2001). However, reviews of recent aerial photographs along the I-90 Corridor Alternatives suggest that there would be substantially more than 21.9 acres of wetlands affected by implementation of the alternatives, and USGS appears to have categorized some of the wetland areas as "developed land" that is adjacent to the I-90 corridor. Although it is likely that the proposed Project would affect more wetland area than the alternatives, the difference is likely less than 70 acres. Mitigation measures would be implemented to avoid or minimize the impacts to wetlands, and for jurisdictional wetlands, compensatory mitigation would likely be required as part of the USACE Section 404 permitting process.

The alternative routes would also affect almost 20 times more acres of developed land (approximately 2,201 acres versus 92 acres), including land within or near several communities along the routes. These include Oacoma, Mitchell, Alexandra, and Emery, South Dakota. Impacts in those areas would be related primarily to construction, although it is possible that both pump stations and MLVs could be in the vicinity of the developed areas and would affect visual quality and create noise impacts during operation. However, there has not been a hydraulic design of the I-90 Corridor Alternatives and it is not possible to identify the locations of pump stations or MLVs at this time.

DOS received many comments in 2007 on the draft EIS for the Keystone Oil Pipeline Project. Specific concerns were expressed at that time from residents of South Dakota and Nebraska relative to the possibility of future pipelines following the Keystone Mainline pipeline route. Commenters from South Dakota were concerned about impacts of the Keystone Oil Pipeline Project crossing of the Missouri River, especially through a National Wild and Scenic River reach. The Keystone Corridor Alternative would cross the Missouri River in the same reach. Additional concerns were related to rural water supply impacts, including the WEB, Clark, Hanson, Turner McCook, Lewis and Clark, and B-Y water systems.

Concerns raised in 2007 by commenters from Nebraska included the project route through Seward, Nebraska and potential impacts to the Seward water system. In all three states, the presence of shallow groundwater aquifers beneath the Keystone route was a concern, including concerns about potential impacts to the NHPAQ system, which includes the Ogallala aquifer. In essence, the I-90 Corridor Alternatives, while reducing the distance over the shallow groundwater of the Sand Hills Unit of the NHPAQ system and other portions of the NHPAQ system, would transfer the shallow groundwater risks to shallow aquifers in other regions, including other shallow aquifers within Nebraska.

In summary, the I-90 Corridor Alternatives would not eliminate the risk of an accidental release from the pipeline, but would simply transfer that same risk from one portion of the NHPAQ to other groundwater aquifers, including other shallow aquifers within Nebraska. Additionally, as depicted in Figure 4.3.3-6, the risk would be transferred from an area of relatively low ongoing groundwater usage within the Sand Hills topographic region to areas of high ongoing groundwater usage elsewhere. In either case, the pipeline would be constructed using special techniques that would reduce potential construction impacts through the Sand Hills topographic region, and as a result of the 57 Project-specific Special Conditions, would be constructed in its entirety with a degree of safety over any other typically constructed domestic oil pipeline system under current code and a degree of safety along the entire length of the pipeline system similar to that which is required in HCAs as defined in 49 CFR 195.450.

In addition, the comparisons of key environmental issues and the greater area of impact of the I-90 Corridor Alternatives suggest that the alternatives would not offer an overall environmental advantage over the proposed Project route. Finally, crossing Lake Francis Case using the HDD method may not be technically feasible due to the length of the crossing, the height of the bluff on the eastern shore of the lake, and the depth of required boring. Detailed engineering studies would be required to determine whether or not the HDD crossing is technically feasible, including geotechnical studies to determine whether or not the soil conditions in the bluff and under the river would be receptive to using HDD. If HDD is not suitable, a wet-cut crossing using barges and bottom dredging would likely be required. With this method there would be substantial construction impacts to water quality, fisheries habitats, benthic communities, and recreational uses as compared to the impacts of the proposed Project.

As a result of these considerations, the I-90 Corridor Alternatives were eliminated at the screening level from further consideration.

4.3.3.6 Baker Alternative

The Baker Alternative was developed in response to an agency request made during the scoping period. The alternative deviates from the proposed route in the vicinity of Baker, Montana and extends through an area that had previously been disturbed by ongoing construction and operation of oil production and delivery systems (see Figure 4.3.3-1 and Figure 4.3.3-7). The Baker Alternative would deviate from the proposed Project route in Fallon County, Montana and would extend for approximately 62.1 miles parallel to an existing pipeline ROW into Bowman County in southwest North Dakota. The alternative would return to the ROW of the proposed Project in Harding County, South Dakota. The Baker Alternative would be approximately 2.4 miles shorter than the segment of the proposed Project route it would replace. It would also cross an existing oil and gas field southeast of Baker. Within the existing oil and gas field, construction of the alternative would require special pipe crossing techniques. Construction could result in interruptions to crude oil production gathering systems and an increase in the potential for environmental impacts resulting from damage to gathering system pipelines. There would also be a human health and safety concern, including potential injury to pipeline construction workers and the public, due to the proximity of the Baker Alternative to existing oil wells with the potential to release hydrogen sulfide. A comparison of the impacts on key environmental resources of the Baker Alternative to those of the proposed route is provided in Table 4.3.3-3. This alternative would extend through the Baker Lake watershed and would cross substantially less agricultural land and less forested land and wetlands than the comparable segment of the proposed route. However, it would also cross more developed areas, rangeland and grassland, and streams and rivers than the proposed route and would affect a substantially larger area of BLM land.

TABLE 4.3.3-3
Impact Comparisons for the Baker Alternative and the Associated Segment of the Proposed Route

Characteristic	Proposed Route	Baker Alternative
Total Length of Alternative (Miles)	851.6	849.1
Length of Segment of Proposed Route and Baker Alternative (Miles)	64.5	62.1
Land Use (Acres)[a]		
Agricultural Land	102.0	34.7
Barren Land	0.0	1.2
Developed Land	1.8	7.8

Forested	3.0	0.9
Rangeland/Grassland	747.9	781.2
Wetlands	5.3	2.2
Open Water	0.0	0.0
Total	860.0	828.0
Federal Land Ownership (Acres)[b]		
Bureau of Land Management	2.7	163.8
Number of Streams and /Rivers crossed[c]	37	47

[a] Data in remainder of table are for the segment of the proposed route that would be replaced and for the Baker Alternative. Land use from USGS 2001. Acres calculated based on a 110-foot-wide ROW and the pipeline miles of each land use crossed.
[b] Federal lands from ESRI 2004a. Acres calculated based on a 110-foot-wide ROW and the pipeline miles of each land use crossed.
[c] Streams and rivers from ESRI 2004b.

Implementation of the Baker Alternative would create additional unique environmental risks and safety concerns by crossing an existing oil and gas field and the alternative would not offer an overall environmental advantage over the segment of the proposed route it would replace. Therefore the Baker Alternative was eliminated from further consideration.

4.3.4 Western Alternative (Alternative to Both Steele City Segment and the Cushing Extension)

The Western Alternative would substitute for both the Steele City Segment and the Cushing Extension. This approximately 1,277-mile-long alternative would enter the U.S. at Morgan and extend through Montana, South Dakota, Nebraska, Kansas, and Oklahoma to the control point at the southern end of the Cushing Extension as depicted on Figure 4.3.3-1.

Although the Western Alternative would parallel the existing Express-Platte System corridor for approximately 350 miles, the existing easements along that corridor are in the control of a different company and it may not be possible to construct the alternative pipeline within the existing ROW. Therefore, construction of the alternative may result in the same impacts as construction of a pipeline of similar length that is not parallel and adjacent to an existing ROW.

A comparison of the impacts on key environmental resources of the Western Alternative to those of the proposed route is provided in Table 4.3.4-1. The Western Alternative would be approximately 426 miles longer than the proposed route and would affect about 6,000 more acres than the proposed route, including the 100-foot-wide construction ROW, extra work space areas, additional pipe and construction yards, and additional access roads. The Western Alternative would affect substantially more agricultural land, developed land, forested land, rangeland and grassland, and wetlands than the proposed route. It would also cross substantially more streams, rivers, and federal land than the proposed route. The Western Alternative would avoid crossing the NHPAQ system and the Sand Hills topographic region of Nebraska. The route would also avoid crossing the Charles M. Russell National Wildlife Refuge, the Medicine Bow National Forest, and the Pawnee National Grassland.

The Western Alternative is not considered a reasonable alternative to the proposed Project due to the financial impracticability of constructing a pipeline that would be substantially longer than the proposed route. In addition, the Western Alternative would not offer an overall environmental advantage over the proposed route. Therefore, this alternative was eliminated from further consideration.

TABLE 4.3.4-1 Impact Comparisons for the Proposed Route and the Western Alternative		
Characteristic	**Proposed Route**	**Western Alternative**
Total Length (Miles)	851.6	1,277.4
Land Use (Acres)[a]		
Agricultural Land	2,978.6	4,672.2
Barren Land	6.3	55.3
Developed Land	174.2	505.0
Forested	33.0	327.8
Rangeland/Grassland	8,006.7	11,136.4
Wetlands	148.1	247.5
Open Water	15.8	87.8
Total	11,362.7	17,032.0
Federal Land Ownership (Acres)[b]		
Bureau of Land Management	595.2	2,250.8
Bureau of Reclamation	0.0	277.4
National Park Service	0.0	0.0
Total	595.2	2,528.2
Number of Streams and Rivers crossed[c]	454	821

[a] Land use from USGS 2001. Acres calculated based on a 110-foot-wide ROW and the pipeline miles of each land use crossed.
[b] Federal lands from ESRI 2004a or National Park Service 2010a. Acres calculated based on a 110-foot-wide ROW and the pipeline miles of each land use crossed.
[c] Streams and rivers from ESRI 2004b.

4.3.5 Gulf Coast Segment Alternative Routes

The Gulf Coast Segment extends from the southern end of the Cushing Extension to the proposed Project's delivery point at Nederland, Texas. Two route alternatives for the Gulf Coast Segment were identified: the proposed route (Alternative GCS-A) and Alternative GCS-B. These alternatives are depicted on Figure 4.3.5-1 and compared below.

The proposed route would be approximately 480 miles long and would parallel an existing natural gas pipeline corridor (Texoma Pipeline) from Cushing to Nederland (portions of the Texoma line have been sold and are operated by other companies, but the corridor is still intact). The proposed Project route would avoid the Angelina National Forest in Angelina, Nacogdoches, San Augustine, and Jasper counties in east Texas along the shores of the Sam Rayburn Reservoir. Alternative GCS-B would be west of the proposed route and closer to the Dallas-Ft. Worth metropolitan area than the proposed route and would extend east of Durant, Oklahoma.

Both routes would extend through active and inactive oil and gas fields south of Cushing. Approximately 82 percent of the proposed route would parallel the existing ROWs of other linear facilities. Approximately 98 percent of Alternative GCS-B would parallel existing ROWs, including 190 miles of the Seaway Pipeline ROW south of Cushing before diverting to a path that would pass east of Lake Texoma. It is not known whether Alternative SCS-B would be constructed within existing ROWs and therefore it is not clear that it would offer an environmental advantage over the proposed route due to the use of more existing ROWs.

Both alternative routes would avoid the Big Thicket Natural Preserve in Liberty County, Texas by routing the pipeline along the Texas highway. The Big Thicket Natural Preserve is a combination of pine and cypress forest, hardwood forest, meadow, and blackwater swamp, and in 2001 the American Bird Conservancy designated the Big Thicket National Preserve as a Globally Important Bird Area (National Park Service 2010b). The predominant ownership along the proposed route is private land, with less than 1 percent of the ROW corridor owned by either the State of Oklahoma or Texas.

A comparison of the impacts on key environmental resources of the two Gulf Coast Segment alternatives is provided in Table 4.3.5-1. The proposed route would cross more wetlands and forested land than Alternative GCS-B. However, Alternative GCS-B would cross more agricultural land, rangeland and grassland, developed land, more open water and rivers and streams than the proposed route. In addition, Alternative GCS-B would be in close proximity to more developed areas along its route than the proposed route. Alternative GCS-B would be 6 miles longer than the proposed route and would affect about 90 more acres during construction, including the 110-foot-wide construction ROW, extra work spaces, additional contractor and pipe yards, and additional access roads.

As a result, Alternate GCS-B would not offer an overall environmental advantage over the proposed route and was eliminated from further consideration.

TABLE 4.3.5-1
Impact Comparisons for the Gulf Coast Segment Alternatives

Characteristic	Proposed Route (Alternative GCS-A)	Alternative GCS-B
Length (Miles)	480	486
Land Use (Acres)[a]		
Agricultural Land	1,646.4	1,974.8
Barren Land	3.7	4.2
Developed Land	346.1	381.8
Forested	1,930.5	1,185.7
Rangeland/Grassland	1,767.8	2,378.8
Wetlands	747.6	552.8
Open Water	8.5	20.6
Total	6,450.6	6,498.7
Number of Streams and Rivers crossed[b]	246	255

[a] Land use from USGS 2001. Acres calculated based on a 110-foot-wide ROW and the pipeline miles of each land use crossed.
[b] Streams and rivers from ESRI 2004b.

4.3.6 Houston Lateral Alternative Routes

The Houston Lateral would extend from the Gulf Coast Segment to a point in the Moore Junction area east of Houston. Moore Junction is a large area that extends to the north and south of the Houston Ship Channel and includes a large number of oil industry facilities. Two route alternatives for the Houston Lateral were identified: the proposed Project route (Alternative HL-A) and Alternative HL-B. These alternatives are depicted on Figure 4.3.6-1 and compared below. As indicated on Figure 4.3.6-1, the alternatives have different starting and ending points.

The proposed route would be 48.6 miles long and would initiate at a point on the Gulf Coast Segment in central-east Liberty County. From there it would extend south and west through Chambers County to

Harris County, ending near Moore Junction, north of the Houston Ship Channel. Approximately 40 percent of the proposed route would parallel other utility corridors.

Alternative HL-B would start at Nederland (Jefferson County) and extend in a west-southwest direction to a point north of the main body of Galveston Bay, then extend to the southwest and would terminate near Moore Junction, south of the ship channel. The route would be approximately 77.4 miles long with 97 percent of the route paralleling other utility corridors. It would extend through Jefferson, Liberty, Chambers, and Harris counties. Although Alternative HL-B would be parallel to substantially more existing ROWs, it is not known whether it would be constructed within existing ROWs and therefore it is not clear that it would offer an environmental advantage over the proposed route due to the use of more existing ROWs.

Alternative HL-B would be about 30 miles longer than the proposed route and would affect about 400 more acres during construction, including the 110-foot-wide construction ROW, extra work spaces, additional contractor and pipe yards, and additional access roads.

The southwestern end of the proposed route would extend through heavily developed urban areas in the east Houston area. Both the beginning and ending portions of Alternative HL-B would also extend through heavily developed urban areas.

The proposed route would extend through approximately 4 miles of land within the Coastal Zone Management Area (CZMA) along the Gulf Coast. Any project that may affect land or water in the Texas coastal zone and that requires a federal license or permit must be reviewed for consistency with the Texas Coastal Management Program. Assuming a 110-foot-wide construction ROW, there would be approximately 60 acres affected within the CZMA in Harris County, including extra work spaces and additional access roads. It is not likely that contractor and pipe yards would be required within that distance.

Alternative HL-B would cross approximately 31 miles of land within the CZMA in Harris and Chambers counties, and construction would disturb about 450 acres, including the 110-foot-wide construction ROW, extra work spaces, additional contractor and pipe yards, and additional access roads. As a result, Alternative HL-B would affect about 390 more acres in the CZMA than the proposed route. Alternative HL-B would likely encounter greater regulatory barriers than the proposed route due to its proximity to the Gulf Coast and due to the area of the coastal zone that would be affected.

Alternative HL-B would require a marine crossing of an arm of Galveston Bay in the vicinity of the Houston Ship Channel. The crossing distance would be approximately 1.8 miles, and would produce impacts to benthic communities and nearshore environment along the proposed route. In comparison, the proposed Project route would not cross any portion of Galveston Bay.

A comparison of the impacts on key environmental resources of the two Houston Lateral alternatives is provided in Table 4.3.6-1. The proposed Project route would cross less agricultural land, less developed land, less rangeland and grassland, and fewer streams, rivers, and other open water than Alternative HL-B. However, it would also cross through more wetlands and federal lands than Alternative HL-B.

As compared to proposed route, Alternative HL-B would be longer and would have a larger area of impact due to construction, would have substantial coastal zone concerns, would cross more developed land in urban areas, and more rivers, streams, rangeland and grassland, and agricultural land. Most importantly, it would involve a marine crossing of an arm of Galveston Bay. As a result, Alternative HL-B would not offer an overall environmental advantage over the proposed route and was eliminated from further consideration.

TABLE 4.3.6-1 Impact Comparisons for the Houston Lateral Alternatives		
Characteristic	**Proposed Route (Alternative HL-A)**	**Alternative HL-B**
Total Length (Miles)	48.6	77.4
Land Use (Acres)[a]		
Agricultural Land	286.5	438.7
Barren Land	0.0	0.3
Developed Land	27.4	208.5
Forested	27.1	11.7
Rangeland/Grassland	66.6	182.4
Wetlands	236.5	165.5
Open Water	3.9	24.9
Total	648.0	1,032.0
Federal Land Ownership (Acres)[b]		
U.S. Fish and Wildlife Service	46.7	18.7
Number of Streams and Rivers crossed[c]	12	28

[a] Land use from USGS 2001. Acres calculated based on a 110-foot-wide ROW and the pipeline miles of each land use crossed.
[b] Federal lands from ESRI 2004a or National Park Service 2010a. Acres calculated based on a 110-foot-wide ROW and the pipeline miles of each land use crossed.
[c] Streams and rivers from ESRI 2004b.

4.3.7 Route Variations

A variation is a relatively short deviation from a proposed route that is developed to resolve or reduce construction impacts to localized, specific resources such as cultural resource sites, wetlands, recreational lands, residences, and terrain conditions. Variations are different from major route alternatives in that alternatives are typically substantial distances from proposed pipeline routes, are generally much longer than variations, and are developed to reduce overall environmental impacts, reduce or eliminate engineering and constructability concerns, and avoid or minimize conflicts with existing or proposed residential and agricultural land uses while meeting the goals of a project. Although route variations also may be many miles in length, they are typically shorter and nearer to a proposed route than a major route alternative. Many requests for variations were submitted by concerned landowners during the review period for the draft EIS as well as in direct negotiations with Keystone as design of the proposed route progressed.

Because most route variations were identified to avoid or minimize specific environmental impacts and land use conflicts, in response to landowner comments, and to increase the use of public land in Montana consistent with the requirements of MFSA, they may not in all cases display a substantial environmental advantage over the segments of the proposed Project route that they would replace. Since the variations are generally close to the route segments they would replace and for the most part extend across similar terrain, the construction methods would be essentially the same and the visual character of the variations would be essentially the same as that of the proposed Project after reclamation is complete. In most cases, the impacts associated with implementation of the variations would be essentially the same as the impacts that would result from construction and operation of the route segments that the variations would replace.

Route variations assessed in this analysis include:

- Variations in Montana (Section 4.3.7.1);
- Niemi Variation in South Dakota (Section 4.3.7.2); and
- Minor Realignments Negotiated with Landowners (Section 4.3.7.3).

4.3.7.1 Montana (New Section)

In Montana, MFSA and MEPA require that MDEQ implement a specific process to identify landowner concerns, preferential use of public lands, and other considerations to develop alternatives to proposed routes. A detailed discussion of the requirements of MFSA and MEPA is included in Section 1.0 of Appendix I to the draft EIS. As noted in that section, MDEQ must identify the route that minimizes adverse environmental impacts and uses public land (which may include federal land) whenever the use of public lands is as economically practicable as the use of private land before it can approve the proposed Project or any alternative to the proposed Project.

In addition to the alternatives described in Sections 4.1, 4.2, and 4.3.1 through 4.3.6, MDEQ required that Keystone identify and assess two additional alternative routes in Montana that would increase the use of public lands in comparison to the proposed route. These alternative routes were developed using a GIS database model (i.e., ground surveys were not conducted) that incorporated a set of weighted environmental factors agreed to by MDEQ. Using that approach, the Canada to North Dakota (CND) and Canada to South Dakota (CSD) alternatives were developed and compared at a screening level to the proposed route relative to environmental impacts and the use of public lands. As described in detail in Section I-2.0 of Appendix I to the draft EIS, both routes were eliminated from further consideration as a result of this screening analysis. However, MDEQ identified portions of the CSD Alternative that would cross more public land than the segments of proposed Project route they would replace and considered them as potential route variations. MDEQ also identified additional route variations that would avoid or minimize impacts to specific resources, minimize conflicts with existing or proposed residential and agricultural land uses, and that responded to requests submitted by concerned landowners during both the scoping period and the draft EIS comment response period.

In total, MDEQ identified 19 potential route variations in Montana and prior to the draft EIS, preliminarily selected 9 of these variations as preferable to the segments of the proposed route that they would replace. As a result of continuing review and analysis, MDEQ has revised its selection of potential route variations and will develop a preferred route that includes portions of the proposed Project route and selected route variations out of a total suite of nearly 100 potential route variations assessed. MDEQ mailed a certified letter to each of the landowners affected by these potential variations and requested comments. In addition, where requested, MDEQ staff met affected landowners in the field to further describe the routing variations and listen to landowner concerns and suggestions for further adjustments. These variations will be addressed in the final EIS. Beginning in mid to late April, these suggested routing variations in Montana can be viewed at MDEQ's web site: http://svc.mt.gov/deq/wmaKeystoneXL/. MDEQ will continue to consider these and other route variations prior to completing the MFSA review process and issuing a Certificate of Compliance. The variations that MDEQ may ultimately select are relatively close to the proposed Project route segments they would replace. Both DOS and MDEQ have conducted environmental reviews of the proposed Project route in Montana as reported in this EIS. MDEQ maintains information related to the proposed Project on its website located at: http://deq.mt.gov/MFS/KeystoneXL/KeystoneXLIndex.mcpx. Along with information related to Keystone's application and the EIS review and comment process, the website

also provides an interactive map detailing available updates to the proposed Project variations in Montana and the MDEQ suggested variations. Though the website is intended to provide the most up-to-date data when available, information not provided on the site will be included in the final EIS.

4.3.7.2 South Dakota (New Section)

As a result of negotiations with two landowners in the vicinity of Buffalo, South Dakota, Keystone surveyed the landowners' properties and developed a route variation that would avoid areas that were being developed for commercial excavations of paleontological resources. The variation, termed the Niemi Route Variation, diverts from the proposed route just north of MP 309 on the Steele City Segment, and returns to the proposed route just north of MP 315. The segment of the proposed route that would be replaced is about 6.56 miles long, and the variation is about 7.02 miles long, or about 0.46 miles longer than the proposed route. The routes of the variation and the segment of the proposed route it would replace are depicted on Figure 4.3.7-1 and the impacts of the two routes on key environmental resources are compared in Table 4.3.7-1.

The variation is slightly longer than the proposed route, but would cross less state land than the segment of the proposed route it would replace. Both the variation and the segment of the route it would replace have one isolated cultural resources find, and neither is eligible for nomination to the NRHP. The Keystone survey identified a rock cairn along the route of the variation. The site is potentially eligible for the NHRP, but impacts would be mitigated through construction avoidance methods including necking and fencing.

As noted in Table 4.3.7-1, the variation would cross 4 more intermittent streams and 3 more wetlands than the proposed route. Impacts to these resources would be avoided or minimized by incorporating the permitting requirements of the USACE Nationwide Permit and the procedures described in Keystone's CMR plan (Appendix B of the draft EIS).

During 2009 field surveys, sage grouse leks were not identified near either the proposed Project route or the Niemi Route Variation. However, data from the South Dakota Game, Fish and Parks Department indicates that there are two historic (inactive) leks about 0.2 mile southwest of the Niemi Route Variation. Raptors, raptor nests, or bald eagle winter roost sites were not identified during aerial raptor surveys conducted in February and April 2009 along either the proposed route or the Niemi Route Variation.

Field surveys conducted in November 2010 determined that (1) the proposed route would cross multiple locations of known paleontological resources as well as an ongoing commercial paleontological excavation, and (2) the variation would cross three "significant" (as defined by BLM) paleontological areas, all of which are on private land. Prior to construction surface collections of paleontological resources along the variation would occur and during construction the ROW would be monitored by a qualified paleontological expert.

The Niemi Route Variation would replace a short segment of the overall proposed Project, is relatively close to the proposed route; addresses a specific issue relevant to landowners; would be implemented in accordance with applicable regulatory requirements of federal, state, or local permitting agencies; and would have environmental impacts similar to those of the segment of the proposed route it would replace. As a result, incorporation of the Niemi Route Variation into the proposed Project, with implementation of the procedures described above, is acceptable to DOS.

TABLE 4.3.7-1
Comparison of Niemi Route Variation with the Segment of the Route it Would Replace

Item	Miles of Land Crossed (except where noted)		Difference
	Proposed Route Segment	Niemi Route Variation	
Length	6.56	7.02	-0.46
Land Cover[a]			
Agriculture	0.45	0.37	+0.08
Developed	0.13	0.08	+0.05
Rangeland	5.98	6.57	-0.59
Total	6.56	7.02	-0.46
Land Ownership[b]			
State of South Dakota	0.51	0.48	+0.03
Private Land	6.05	6.54	-0.49
U.S. Bureau of Land Management	0.00	0.00	0.00
Total	6.56	7.02	-0.46
Number of Private Properties	2	2	0
Number of Road Crossings[c]			
Major Roads	1	1	0
Minor Roads	1	0	+1
Total	1	0	+1
Number of Stream Crossings[d]			
Perennial Streams	0	0	0
Intermittent Streams	5	1	+4
Total	5	1	+4

Item	Miles of Land Crossed (except where noted)		Difference
	Proposed Route Segment	Niemi Route Variation	
Slope[e]			
< 5%	6.44	6.93	-0.49
≥ 5% and ≤ 15%	0.12	0.09	+0.03
> 15% and ≤ 30%	0.00	0.00	0.00
> 30%	0.00	0.00	0.00
Number of Water Wells within 100 ft[f]	0	0	0
Number of Residences			
Residences within 25 ft	0	0	0
Residences within 500 ft	0	0	0
Number of Structures			
Structures within 25 ft	0	0	0
Structures within 500 ft	0	0	0
Cultural Resource Findings			
Cultural Findings	1 Not Eligible	1 Not Eligible, 1 Potentially Eligible	-1 Potentially Eligible
Paleontological Findings	1 Significant, 2 Non- Significant	3 Significant	-2 Significant, +2 Non-Significant
Number of Grouse Leks[g]			
Sage-Grouse within 4 miles	0	0	0
Wetlands[g]	2 (PEM)	5 (PEM)	-3 (PEM)
Areas with Noxious Weeds[g]	1	0	+1
Number of Waterbodies[g]	5 ephemeral	1 stream, 1 ephemeral	-1 stream, +4 ephemeral

[a] Land use from USGS 2001.
[b] Federal lands from ESRI 2004a. State land from South Dakota GIS, 2010.
[c] Roads from ESRI 2003.
[d] Streams and rivers from ESRI 2004b.
[e] Slope from USGS 2002.
[f] Well Locations from South Dakota Department of Environment and Natural Resources 2010.
[g] Data from Trow Engineering Consultants 2010; Note: the variation was surveyed, the proposed route segment survey was incomplete.

4.3.7.3 Minor Realignments Negotiated with Landowners

During detailed design of the proposed route and the associated continuing field surveys, areas along the proposed route were identified that would require minor deviations to avoid small but sensitive resources, that would require difficult construction procedures, or that were concerns to landowners due to potential conflicts with existing land uses. As a result, many route variations were identified that would replace segments of the proposed Project route. These variations would replace short segments of the proposed Project, are relatively close to the proposed route and would be implemented in accordance with applicable regulatory requirements of federal, state, or local permitting agencies (see Appendix W of the draft EIS). As a result, incorporation of these variations into the proposed Project in place of the segments they would replace is acceptable to DOS.

4.3.8 Agency-Preferred Route

Alternatives were developed and assessed based on information provided in the Presidential Permit application and supplemental submittals related to the application, information provided by the cooperating agencies, public comments received in the scoping process and on the draft EIS, and information obtained from research of relevant available information conducted by DOS and its third-party contractor.

Based on the assessment of alternatives described above, the DOS-preferred route consists of the following alternatives by segment:

- Steele City Segment: Alternative SCS-B (including route variations in Montana selected by MDEQ, the Niemi Route Variation, and minor route realignments listed in Appendix W of the draft EIS);
- Existing Cushing Extension (including two new pump stations);
- Gulf Coast Segment: Alternative GCS-A; and
- Houston Lateral: Alternative HL-A.

4.4 ALTERNATIVE PIPELINE DESIGN

DOS received comments on the draft EIS requesting consideration of the alternative of constructing the pipeline above ground and comments requesting that we consider the alternative of using smaller diameter pipe for the Project. Those two alternatives are addressed in the following sections:

- Aboveground Pipeline (Section 4.4.1); and
- Smaller Diameter Pipe (Section 4.4.2).

4.4.1 Aboveground Pipeline

Although it is technically feasible to construct the proposed Project pipeline aboveground in most areas along the proposed route, there are many disadvantages to an aboveground pipeline. In comparison to an aboveground pipeline, burying a pipeline reduces the potential for pipeline damage due to vandalism, sabotage, and the effects of other outside forces, such as vehicle collisions. Further, there has been increased concern about homeland security since the September 11, 2001 attacks, and burying the pipeline provides a higher level of security.

In addition, 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 more accessible to those intent on damaging the pipeline.

Nearly all petroleum transmission pipelines in the U.S. are buried. As stated in Section 2.3, the proposed Project would be constructed, operated, maintained, inspected, and monitored in compliance with the PHMSA requirements presented in 49 CFR 195, relevant industry standards, applicable state standards, and a set of Project-specific Special Conditions developed by PHMSA and incorporated into the proposed Project design, operations, maintenance and monitoring commitments. Construction, operation, inspection, and maintenance of the Project in this manner would result in a pipeline system with a higher degree of safety than any other domestic oil pipeline system and with a higher degree of safety along the entire length of the pipeline system than is required in HCAs as defined in 49 CFR 195.450.

As a result, an aboveground pipeline is not a reasonable alternative for the proposed Project and was not further considered.

4.4.2 Smaller Diameter Pipe

As noted in Section 1.2.2, the Project has been proposed to transport a maximum capacity of 830,000 bpd of crude oil to meet current and future market demand for heavy crude oil in PADDs II and III. A pipeline system with a pipe diameter that is less than the proposed Project's 36-inch-diameter pipeline would have lower throughput capacities and would not be capable of providing this volume of crude.

Even if a smaller diameter pipe were commercially viable, construction of smaller lines would have essentially the same impacts as those of the proposed 36-inch-diameter pipe since the construction right-of-way width would be approximately the same for all but the smallest diameter pipe. 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, not the diameter of the pipe itself. For all pipelines over 30 inches in diameter, the working ROW dimensions would be essentially the same.

The proposed pipeline is sized to efficiently deliver the volume of crude oil proposed to be transported by the proposed Project (i.e., an initial capacity of 700,000 bpd and an ultimate maximum capacity of 830,000 bpd with increase pumping capacity). While there are limitations to the ultimate capacity of throughput based on pipeline diameter, the operational throughput is a 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 it is not likely that those pressures and velocities would be in compliance with PHMSA regulations. Further, even with high pressure and velocity, it is unlikely that a 30-inch-diameter pipeline would be capable of transporting the volumes proposed for transport in the Project. In addition, as of February 2011, Keystone had firm contract commitments to transport 600,000 bpd of crude oil to Cushing (155,000 bpd of WCSB crude oil for delivery to Cushing that is currently contracted for shipment on the Keystone Mainline, 380,000 bpd of WCSB crude oil for delivery to the Gulf Coast, and 65,000 bpd of Bakken crude oil). 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, use of a smaller diameter pipe for the Project was not considered 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 potential alternative was eliminated from further consideration.

4.5 ALTERNATIVE SITES FOR ABOVEGROUND FACILITIES

The major aboveground facilities of the proposed Project consist of pump stations, MLVs, and the Cushing Tank Farm. Alternative sites for those facilities are addressed in the following sections:

- Alternative Pump Station Sites (Section 4.5.1);
- Alternative MLV Sites (Section 4.5.2); and
- Alternative Tank Farm Sites (Section 4.5.3).

Pig launching and receiving facilities would be located within pump stations, and therefore alternate sites for those facilities are not addressed separately.

4.5.1 Alternative Pump Station Sites

All pump stations for the proposed Project would be sited within the permanent ROW. As a result, alternate locations for pump stations were included in general in the assessment of alternate pipeline routes discussed in Section 4.3. The specific sites selected for pump stations were based on system hydraulics, and there would be a minimal distance along the pipeline corridor for alternate pump station sites due to the pumping requirements of each portion of the system. Minor modifications in pump station footprint location may occur as a result of input from appropriate regulatory authorities.

4.5.2 Alternative MLV Sites

All MLVs for the proposed Project would be sited within the permanent ROW. As a result, alternate locations for MLVs were included in general in the assessment of alternate pipeline routes discussed in Section 4.3. In addition, the locations of MLVs must be in compliance with 49 CFR 195.260 and the specific conditions related to MLVs included in the Project-specific Special Conditions developed by PHMSA that Keystone has agreed to incorporate into the Project (see Appendix C of this SDEIS). As a result, there is little option to install MLVs at alternative sites. However, MLV locations have been selected to avoid sensitive environmental resources to the extent practicable while complying with the PHMSA regulatory requirements and will be modified to comply with the relevant Project-specific Special Conditions developed by PHMSA and incorporated into the proposed Project specifications.

4.5.3 Alternative Tank Farm Sites

Initially, the proposed Project included a tank farm at Steele City, Nebraska. That location would have provided opportunities for batch shipment on either the proposed Project or the existing Keystone Mainline pipeline. It was later determined that installing the tank farm at Cushing would be preferable from an operational perspective and would provide better options for delivery systems interconnection and tankage installation for the Bakken Marketlink and the Cushing Marketlink projects if either or both of those projects are implemented (see Sections 2.5.3 and 2.5.4 for information on the potential Bakken Marketlink and Cushing Marketlink projects).

The proposed Cushing tank farm site was selected to be adjacent to the proposed site of pump station 32. It is also less than 0.5 mile from the existing Cushing Oil Terminal, which is the largest oil terminal in the U.S. Siting near the pump station and the existing terminal would avoid disturbance to areas farther from the facility and would eliminate the need for a connecting pipeline extending beyond the proposed ROW. As described in Section 3.0, construction and operation of the Cushing tank farm would not result in substantial impacts. As a result, there do not appear to be any alternative tank farm sites that would offer an overall environmental advantage to the proposed site.

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[FIGURE PLACEHOLDER]

4.1.2-1 Proposed Enbridge Northern Gateway Project and Planned Trans Mountain Pipeline Expansions

4.3.2-1 Major Existing Pipelines Overlying Northern High Plains Aquifer System

4.3.3-1 Steele City Segment Alternatives

4.3.3-2 Alternatives Associated with Northern High Plains Aquifer System

4.3.3-3 Keystone Corridor Alternative Key Aquifers and Potable Water Wells within 2-mile Corridor

4.3.3-4 I-90 Corridor Alternatives

4.3.3-5 I-90 Corridor Alternatives Lake Francis Case Area

4.3.3-6 I-90 Corridor Alternatives Key Aquifers and Potable Water Wells within 2-mile Corridor

4.3.3-7 Baker Alternative

4.3.5-1 Gulf Coast Segment Alternatives

4.3.6-1 Houston Lateral Alternatives

4.3.7-1 Niemi Variation