CONSOLIDATED RESPONSES

Consolidated Responses to Comments on the Draft EIS and the Supplemental Draft EIS for the proposed Keystone XL Project

The U.S. Department of State (DOS) prepared the "Consolidated Responses" presented in this section of Appendix A as a part of its response to comments on the draft EIS and the supplemental draft EIS. The consolidated responses address topics that were commented on by multiple reviewers. The codes used for the issues that are addressed in the consolidated responses are listed in Table A-1.

The individual substantive comments received on the draft EIS are presented in spreadsheets in Appendix A. The spreadsheets are organized by topic; e.g. the EAS spreadsheet includes comments and responses related to easements. Where appropriate, responses in the spreadsheets refer to a consolidated response or in some cases to multiple consolidated responses. The individual comments on the supplemental draft EIS are also presented in spreadsheets in Appendix A and are addressed in a similar fashion.

TABLE A-1
Issue Codes for Consolidated Responses to Comments on the Draft and Supplemental Draft EISs

Code	Issue
ALT-1	Concerns regarding potential alternative routes and system alternatives
ALT-2	Concerns regarding alternative energy sources and technologies and energy conservation
ALT-3	Concerns regarding a potential connection to the proposed Project in Montana for Williston Basin crude oil
AQF-1	Concerns regarding potential risk to Northern High Plains Aquifer system
AQF-2	Concerns regarding pipeline alignment through shallow aquifers
AQF-3	Concerns regarding potential contaminant migration and spill response
AQF-4	Concerns regarding appropriate land use in Northern High Plains Aquifer system area
AQF-5	Concerns regarding potential threats to aquifers from terrorism and natural disaster
AQF-6	Concerns regarding aquifer protection
CAN-1	Concerns regarding oil sands production with and without the proposed Project
CMT-1	Concerns regarding the length of the comment periods
CMT-2	Concerns regarding the number and location of public comment meetings and requests for more public involvement
CMT-3	Concerns regarding the level of information provided to the public on the proposed Project and the scoping meeting locations and schedules
CMT-4	Requests for draft EIS comment meetings near Houston, Texas and in Washington, DC
CMT-5	Concerns that scoping and the draft EIS did not identify all state and federal activities and agencies involved
CMT-6	Concerns that not enough paper copies of the draft EIS were available
CST-1	Requests to construct the pipeline aboveground
CUL-1	Concerns regarding the protection of historic properties and consultation under Section 106 of the National Historic Preservation Act
DEC-1	Concerns regarding the life of the proposed Project and decommissioning of the proposed Project
EAS-1	Concerns regarding pipeline routing in Montana
EAS-2	Concerns regarding easement negotiations, eminent domain proceedings, and enforcement of easement agreements
ECO-1	Concerns regarding potential beneficial socioeconomic impacts

TABLE A-1 Issue Codes for Consolidated Responses to Comments on the Draft and Supplemental Draft EISs	
Code	**Issue**
ELE-1	Concerns regarding the source of electrical power for pump stations
ENR-1	Requests for denial or approval of the Presidential Permit application and for suspending review of the proposed Project and adequacy of the EIS
ENV-1	Concerns regarding sensitive and fragile environments and ecosystems
ENV-2	Concerns regarding pipeline temperature effects
ENV-3	Concerns regarding potential impacts to native grasslands and prairies
ENV-4	Concerns regarding oil sands production and migratory birds
ENV-5	Requests for use of horizontal directional drilling for all wetlands and waterbodies
ENV-6	Concerns regarding the influence of climate change on the potential impacts of the proposed Project
ERO-1	Concerns regarding Sand Hills erosion
ERO-2	Concerns regarding erosion adjacent to streams and private land
FRM-1	Concerns regarding potential impacts to ranches and farmland
FRM-2	Concerns regarding potential impacts to irrigated cropland
GEO-1	Concerns regarding Landslide potential
GEO-2	Concerns regarding potential seismic and earthquake fault hazards
GEO-3	Concerns regarding Potential geologic hazards
GHG-1	Concerns regarding Greenhouse gas lifecycle analyses
GHG-2	Concerns regarding a potential causal connection of implementation of the proposed Project and expanded oil sands production in Alberta and increases in refining in the Gulf Coast
GHG-3	Concerns regarding change in the rate of greenhouse gas emissions from oil sands production and the influence of implementation of the proposed Project on commitments to alternative and renewable energy
GHG-4	Concerns regarding the loss of boreal forest and peat bogs
GHG-5	Concerns regarding EPA reporting requirements for GHG emissions and CEQ guidance on greenhouse gas assessments
GHG-6	Concerns regarding consideration of low carbon fuel standards in the greenhouse gas assessment
GLF-1	Comparison of an oil spill from the proposed Project to the Deepwater Horizon incident in the Gulf of Mexico
INT-1	Concerns regarding the Notice of Intent
JUS-1	Concerns regarding environmental justice (potential for disproportionate impacts to minority and low-income populations)
LIA-1	Concerns regarding Keystone’s liability for a spill
LIA-2	Concerns regarding bonding and decommissioning
NOI-1	Concerns regarding the potential impacts of noise from pump stations
NOX-1	Concerns regarding the potential spreading of noxious weeds
OIL-1	Concerns regarding the likelihood of spills
OIL-2	Calculation of maximum spill size
OIL-3	Concerns regarding the detection of small leaks
OIL-4	Concerns regarding the composition of crude oil that would be transported by the proposed Project
OIL-5	Concerns regarding the potential for an explosion
P&N-1	Concerns regarding the need for the proposed Project
P&N-2	Concerns regarding the export of crude oil and refined products from the U.S. Gulf Coast
P&N-3	Concerns regarding refinery emissions

TABLE A-1
Issue Codes for Consolidated Responses to Comments on the Draft and Supplemental Draft EISs

Code	Issue
P&N-4	Concerns regarding Chinese investments
P&N-5	Requests to invest in other technologies and for consideration of energy policies
P&N-6	Requests for a supplemental draft EIS
P&N-7	Concerns regarding Keystone's purpose for the proposed Project
P&N-8	Requests to ship Canadian crude oil to refineries that are closer to the source of crude oil
P&N-9	Requests for information on the National Interest Determination process
PIP-1	Concerns regarding the purchase of pipe for the proposed Project
PVT-1	Concerns regarding the cumulative effects of several pipelines through an area
PVT-2	Concerns regarding the proximity of the proposed Project to existing structures and facilities
PVT-3	Landowner comments related to construction of the existing Keystone Oil Pipeline
RDS-1	Concerns regarding potential road damage and roadway safety
REG-1	Concerns regarding Keystone's request for a Special Permit for the proposed Project
REG-2	Concerns regarding the Department of State as the lead federal agency, regulating commerce and permitting for the safe design of the proposed Project
REQ-1	Requests for additional information, including maps of the proposed Project
REQ-2	Requests for locations of paper copies of the EIS, and that copies of the draft EIS, other specific information, or references be sent directly to the commenter
REQ-3	Requests to see comments and responses to comments on the draft EIS
RES-1	Concerns regarding emergency response plans
RUR-1	Concerns regarding potential changes to rural lifestyles
SAF-1	Concerns regarding the design and safety of the proposed Project
SOI-1	Concerns regarding construction during wet weather conditions
SOI-2	Concerns Regarding topsoil, backfill, and restoration
TAX-1	Concerns regarding taxes
TER-1	Concerns Regarding the Potential for terrorism
VAL-1	Concerns regarding property values
WAT-1	Concerns regarding potential water quality impacts
WAT-2	Concerns regarding a compensatory mitigation plan for jurisdictional wetlands and potential impacts to non-jurisdictional wetlands
WAT-3	Concerns regarding potential impacts to wetlands and waterbodies due to construction of ancillary facilities
WAT-4	Concerns regarding the potential for the release of drilling fluids during horizontal directional drilling
WIL-1	Concerns regarding the approach to wildlife analyses
WIL-2	Concerns regarding species covered by the Migratory Bird Treaty Act and the Endangered Species Act

Consolidated Response ALT-1:
Concerns Regarding Potential Alternative Routes and System Alternatives

Many commenters requested that Keystone use routes for the proposed Project that are different from the proposed route (i.e., alternative routes). The majority of commenters expressed an interest in an alternative that would avoid the Northern High Plains Aquifer (NHPAQ) system within which the Ogallala Formation is a hydrogeologic unit (see Consolidated Response AQF-1). Other commenters suggested that crude oil that would be transported by the proposed Project should be transported using other existing pipelines (i.e., system alternatives), and should consider alternative routes starting at border crossings other than the proposed border crossing near Morgan, Montana. As a result of these comments, the analysis of alternatives in both the supplemental draft EIS and the final EIS was expanded. The analysis of alternatives in the EIS is considered to be consistent with the requirements of a NEPA environmental review.

Alternative Routes

Section 4.3 of the EIS includes the alternatives analysis required under the National Environmental Policy Act (NEPA). Appendix I of the EIS includes the alternatives analysis required by the Montana Department of Environmental Quality (MDEQ) under the requirements of both the Montana Environmental Policy Act (MEPA) and the Montana Major Facility Siting Act (MFSA).

As described in Section 4.3 of the EIS, most alternative routes considered under NEPA would have to connect to several proposed Project control points to meet the proposed Project's purpose and need. The control points are (1) the point where the previously approved Canadian portion of the Keystone XL pipeline meets the U.S./Canada border (near Morgan, Montana), (2) the northern end of the existing Cushing Extension of the existing Keystone Oil Pipeline, (3) the southern end of the existing Cushing Extension, and (4) the two proposed delivery points for the crude oil in Texas. These fixed control points placed geographic constraints on potential alternatives, thus limiting the number of alternatives that could be reasonably considered. However, in response to agency scoping comments and comments on the draft and supplemental draft EIS regarding alternatives, alternatives that originated near Hardisty, Alberta, Canada and that would cross into the U.S. at points other than near Morgan, Montana were also considered .

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.

Including the proposed route, the assessment of alternative routes included consideration of the following:

- Nine potential alternative routes in the Steele City Segment (from the international border crossing to a connection with the northern end of the existing Cushing Extension);
- One alternative from the international border crossing to the southern end of the existing Cushing Extension;
- Two alternative routes for the Gulf Coast Segment (from the southern end of the existing Cushing Extension to the delivery point at Nederland, Texas); and
- Two alternatives for the Houston Lateral (from the Gulf Coast Segment to the delivery point in the Moore Junction area east of Houston.

These alternatives included seven routes that would either avoid the NHPAQ system or extend across less of the land overlying the NHPAQ system:

- SCS-A and SCS-A1A;
- I-90 Corridor Alternatives A and B;
- Keystone Corridor Alternatives 1 and 2; and
- The Western Alternative.

The alternatives analysis also included consideration of seven routes that would parallel either a substantial part or all the route of the existing Keystone Oil Pipeline:

- Alternatives SCS-A, SCS-B [proposed route], and SCS-A1A;
- I-90 Corridor Alternatives A and B; and
- Keystone Corridor Alternatives 1 and 2.

The analysis of alternatives indicated that construction and operation of the alternative routes considered would result in substantially greater impacts than those of the proposed Project or did not offer an environmental advantage over the proposed route. As a result, the alternatives were eliminated from further consideration. Section 4.3 of the EIS provides a detailed discussion of the results of the screening analysis.

System Alternatives

Some commenters recommended that the existing Keystone Oil Pipeline be used to ship oil to the northern control point of the Cushing Extension, and other commenters felt that there was sufficient capacity on other existing pipelines to ship oil to the proposed delivery points near the Gulf Coast. System Alternatives are addressed in Section 4.2 of the EIS.

The Keystone Oil Pipeline is currently in operation and is shipping oil from Canada to the U.S. Midwest. The maximum capacity of the Keystone Oil Pipeline is approximately 591,000 bpd, and Keystone has firm commitments of 340,000 bpd for that pipeline system. The proposed Keystone XL Project currently has firm commitments for 380,000 bpd. As a result, the existing Keystone Oil Pipeline System does not have sufficient capacity to transport the crude oil currently contracted for transport on the proposed Project. The southern leg of the existing Keystone Oil Pipeline System ends at the Cushing Oil Terminal in Cushing, Oklahoma and does not extend to the Gulf Coast refineries in Petroleum Administration for Defense District (PADD) III. As described in Sections 1.2 and 1.4 of the EIS and in Responses P&N-1

and P&N-7, the purpose of and need for the proposed Project is to meet the crude oil demand of refineries in PADD II and PADD III. Even if the existing Keystone Oil Pipeline had sufficient capacity to ship the contracted Keystone XL Project crude oil to the existing Cushing Terminal, it would require alternative transportation to reach the Gulf Coast refineries in PADD III, either through new pipeline construction or additional development and/or expansion of truck, rail, and/or barge networks from PADD II to PADD III.

In addition to the existing Keystone Oil Pipeline, the analysis of system alternatives included consideration of the following (see Section 4.2.2 of the EIS):

- The use of three other existing or expanded pipeline systems (the ExxonMobil Pegasus Pipeline, the Express-Platte Pipeline System, and the Alberta Clipper Pipeline Project);
- The use of other proposed or planned pipeline systems (the Altex Pipeline System, the Chinook-Maple Leaf Pipeline System, the Texas Access Pipeline, the Enbridge Trailbreaker Project, the Enbridge-BP Delivery System, the Enbridge Monarch Pipeline, the Seaway Pipeline, the Double E Pipeline; and
- The use of alternative modes of transportation (truck transport, railroad tank car transport, and barge and marine tanker transport).

For the reasons described in Section 4.2, these system alternatives were either not reasonable alternatives or did not offer an environmental advantage over the proposed Project and were eliminated from further consideration.

Consolidated Response ALT-2:
Concerns Regarding Alternative Energy Sources and Technologies and Energy Conservation

Commenters have suggested that alternative energy and efficiency may be a preferable substitute for crude oil in light of environmental concerns, particularly greenhouse gas (GHG) emissions.

Relative to the potential substitution of alternative energy for crude oil that would be transported by the proposed Project, 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.

Relative to reduced use of crude oil for transportation purposes through the implementation of aggressive government strategies and the encouragement of alternative energy use, the EIS discusses ongoing programs to address the intensity of transportation-related fossil fuel consumption. For instance, 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 CO2 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).

The EIS also addresses the potential impact of low carbon fuel standards (LCFS). 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 life-cycle GHG emissions 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.

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.

EPA (2010) reported that implementation of the very aggressive scenario 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 Department of Energy Office of Policy and International Affairs commissioned EnSys (2010) to perform an independent study of various alternatives in transportation infrastructure for crude oil in North America, focused on transport alternatives for crude oil from the WCSB. The results of this study projected that even under EPA's low product demand outlook, a scenario that incorporates the effects of increased use of alternative energy and implementation of aggressive energy efficiency programs, although total crude consumption in the U.S. would decrease, Canadian crude oil imports would increase from 1.9 million bpd in 2009 to 3.6 million bpd by 2030 and WCSB oil sands imports would comprise 90 percent of these Canadian imports. In other words, 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.

For a more extensive analysis of the market demand for crude oil as an energy source versus alternative energy sources see Section 4.1.3 of the EIS. That 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. As stated therein, the use of alternative energy sources and energy conservation in meeting needs for transportation fuel are not considered an alternative to the proposed Project.

Consolidated Response ALT-3: Concerns Regarding a Potential Connection to the Proposed Project in Montana for Williston Basin Crude Oil

Commenters have suggested that the proposed Project should be made available for transporting crude oil produced from the Williston Basin in Montana and North Dakota.

At the time the draft EIS was issued, the State of Montana encouraged Keystone to consider the possibility of a connection (or on-ramp) to the proposed Project in the vicinity of Baker, Montana. That connection would allow producers in the Bakken region of the Williston Basin, which includes producers in both Montana and North Dakota, to ship crude oil to markets not currently available to them. Crude oil produced in that area is light sweet crude. Advances in production technology have resulted in a substantial growth in crude production from this field since the beginning of the decade. The Bakken region does not have existing pipeline infrastructure to support the current level of production and the anticipated growth in that production. As a result, producers currently use rail and truck transportation to ship crude oil produced from the Bakken formation. Due to the high costs associated with these transportation alternatives, Bakken producers must discount their crude oil to be competitive with other sources of crude oil.

After the draft EIS was issued, Keystone Marketlink LLC (Keystone Marketlink), a wholly-owned subsidiary of TransCanada Pipelines Ltd. (TransCanada) announced 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, Texas via the proposed 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 with a less expensive mode of transporting crude oil to markets in Petroleum Administration for Defense District (PADD) II and PADD III. The Bakken Marketlink Project would include storage tanks at the proposed Cushing tank farm that would be used for batch accumulation from the Baker facilities. 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 proposed Keystone 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.

The Bakken Marketlink Project is in the early stages of planning and Keystone Marketlink has not initiated the regulatory review process. That project is not integral to the construction and operation of the proposed Project and is considered a “connected action” for the NEPA environmental review based on the definition provided in the 40 CFR 1508.25:

> “(a) Actions (other than unconnected single actions) which may be:
>
> 1. Connected actions, which means that they are closely related and therefore should be discussed in the same impact statement. Actions are connected if they:
>
>   (i) Automatically trigger other actions which may require environmental impact statements.
>
>   (ii) Cannot or will not proceed unless other actions are taken previously or simultaneously.
>
>   (iii) Are interdependent parts of a larger action and depend on the larger action for their justification.”

Information on the design, construction, and operation of the Bakken Marketlink Project that was available at the time the final EIS was prepared is presented in Section 2.5.3 of the EIS. Keystone Marketlink would be required to obtain permits to construct and operate the planned Bakken Marketlink Project. Although the permit applications for that project would be reviewed and acted on by other agencies, DOS has analyzed the potential impacts of the Bakken Marketlink Project based on the available information. The analyses are discussed in Section 3.15 of the EIS. As noted in Section 3.15, the majority of facilities associated with the planned project would be installed within the boundaries of the proposed Cushing tank farm or adjacent to proposed Pump Station 14 and within the construction right-of-way for the proposed Project. As a result, the majority of the impacts of construction and operation within those areas have been addressed in the resource sections of Section 3.0 of the EIS.

Reviews conducted by the permitting agencies may address potential impacts in greater detail and may identify appropriate mitigation measures that would avoid or minimize impacts.

Several commenters referred to another project, the BakkenLink Pipeline Project, as a potential connected action. The BakkenLink Pipeline Project was announced in June 2010, and in late 2010, the proponents concluded an open season. 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. However, North Dakota's Public Service Commission reported on August 3, 2011 that the proposed BakkenLink Pipeline Project now intends to build a pipeline to a rail loading station that is being developed near Fryburg, about 30 miles west of Dickinson in southwestern North Dakota. The length of the proposed line is being reduced from 250 miles to about 144 miles and is no longer routed into Montana. 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. The BakkenLink Pipeline Project is not considered a connected action but is addressed in the cumulative impacts analysis as a reasonably foreseeable future action (Section 3.14.2 of the EIS).

Commenters on the supplemental draft EIS suggested that the Bakken Marketlink Project could induce accelerated and expanded growth of the Bakken oil field within the Williston Basin. There is no evidence of potential induced growth in the rate of development of the Bakken field in the Williston Basin resulting from the proposed Bakken Marketlink Project. Existing transportation infrastructure (pipeline and rail) combined with projects announced and under construction with target completion dates before 2013 would provide sufficient capacity to transport projected production increases in the Williston Basin for the next decade. The ability to rapidly add transport capacity out of the Williston Basin has been demonstrated over the past three years. The proposed Bakken Marketlink project would compete in the market with other transport options to move Williston Basin crude to refiners in other areas of the country. The Bakken MarketLink proposal reserves space for potential 100,000 bpd of Bakken production of which 65,000 bpd has been committed at this date. The Cushing MarketLink proposal reserves space for a potential 150,000 bpd for crude oil reaching the Cushing area. At this time the Bakken formation in the Williston Basin is producing over 400,000 bpd of crude oil (Investors Business Daily 2011). With current transportation infrastructure Bakken production up to 600,000 to 800,000 bpd could be accommodated. Currently planned rail and pipeline infrastructure could accommodate up to 1.1 million bpd. These production levels from the Bakken formation are consistent with EIA (2011) projections.

Consolidated Response AQF-1:
Concerns Regarding Potential Risk to Northern High Plains Aquifer System and Other Aquifer Systems

Many commenters have expressed concern that the proposed Project would have far reaching effects on the Ogallala aquifer system or other aquifer systems.

The Ogallala Formation is a hydrogeologic unit within the Northern High Plains Aquifer (NHPAQ) system. This aquifer system is located in portions of eight states and as a whole underlies approximately 174,000 square miles of the northern plains. The NHPAQ system includes five main hydrogeologic units: the Brule and Arikaree Formation; the Eastern Nebraska Unit; the Ogallala Formation; the Platte River Valley Unit; and the Sand Hills Unit (see EIS Figure 3.3.1-1). In Nebraska, the NHPAQ system underlies approximately 64,400 square miles. The proposed Project ROW would extend 247 linear miles through areas underlain by the NHPAQ. The proposed Project 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 (see Consolidated Response AQF-2 for additional information).

Any oil spill that could impact groundwater is legitimate cause for concern. To ensure system integrity and reduce oil spill risk, PHMSA developed 57 Project-specific Special Conditions that Keystone has agreed to implement and to incorporate into its manual for operations, maintenance, and emergencies that is required by 49 CFR 195.402 (see Section 2.3, 3.13.1.1 and Appendix U of the EIS. Also see Consolidated Response SAF-1). However, even with the stringent design, operations, and maintenance conditions that would apply to the proposed Project, there is always some risk of a crude oil spill during the lifetime of the pipeline system (see Section 3.13.4.2 of the EIS).

As a result, EPA suggested considering the placement of additional intermediate mainline valves, particularly in areas of shallow groundwater and at river crossings of less than 100 feet where sensitive aquatic resources may exist. Project-specific Special Condition 32 developed in consultation with PHMSA that Keystone agreed to incorporate into the proposed Project plan states:

> "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."

The requirement to take into consideration elevation, population, and environmentally sensitive locations to minimize consequences of a release, and the maximum valve spacing of 20 miles exceed what is currently required in 49 CFR § 195.260. Based on Special Condition 32, the proposed Project was redesigned to increase the number of intermediate mainline valves from 76 to 104 and some previously planned valve locations were moved. As per standard code requirements, there would also be two valves at each of the 30 pump stations. Section 2.2.2 of the EIS has been updated to include information on the additional intermediate valves and valve locations.

EPA also expressed concern that relying solely on pressure drops and aerial surveys to detect leaks may result in smaller leaks going undetected for some time, resulting in potentially large spill volumes. In light of those concerns, EPA requested consideration of additional measures to reduce the risks of undetected leaks, such as external leak detection systems. A PHMSA report (2007) addressed the state of leak detection technology and its applicability to pipeline leak detection. External leak detection technology assessed in that report included liquid sensing cables, fiber optic cables, vapor sensing, and acoustic emissions. The report concluded that while external leak detection systems have proven results for underground storage tank systems, there are limitations to their applicability to long pipeline systems and they are better suited to shorter pipeline segments. The performance of external leak detection systems even in limited application is affected by soil conditions, depth to water table, sensor spacing, and leak rate. Some external detection methods are more sensitive to small leaks than the SCADA computational approach, but the stability and robustness of the systems are highly variable, particularly over long pipeline segments, and the costs are extremely high. Therefore, long-term reliability is not assured and the efficacy of these systems for a 1,384-mile long pipeline is questionable. It may be possible, however, to incorporate external leak detection methods along discrete segments of pipeline where particularly sensitive resources may exist. For example, in the development of the original Keystone pipeline, specific analysis was commissioned at the request of the North Dakota Public Utilities Commission to examine the possibility of using external leak detection in the area of the Fordville aquifer. That analysis was performed by Accufacts, Inc., a widely recognized expert on pipeline safety that has authored a report for the Pipeline Safety Trust on leak detection technology. The Accufacts, Inc. report (2007) on the Fordville aquifer noted:

> "Such real-time external systems should be considered as complementing CPM [computational pipeline monitoring] leak detection in those few ultra-sensitive areas where the environment can quickly spread low rate releases. These systems may be justified in a few areas that can have high consequences because of the number of sensitive receptors (i.e., people) or the potential to critically impact the environment."

The author of the report defined "ultra-sensitive" areas as those areas where low rate or seepage pipeline release could "reach a sensitive area, have serious consequences, and could not be actively remediated." (Accufacts, Inc. 2007).

DOS in consultation with PHMSA and EPA determined that Keystone should commission an engineering analysis by an independent consultant that would review the proposed Project risk assessment and proposed valve placement. The engineering analysis would, at a minimum, assess the advisability of additional valves and/or the deployment of external leak detection systems in areas of particularly sensitive environmental resources. The scope of the analysis and the selection of the independent consultant would be approved by DOS with concurrence from PHMSA and EPA. After completion and review of the engineering analysis, DOS with concurrence from PHMSA and EPA would determine the need for any additional mitigation measures.

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). Potential releases from the proposed Project could be similar to or much larger than typical releases from underground storage tanks. However, since the volume of oil that could be released from the proposed Project is constrained by design factors such as valve spacing and automatic shutoff controls and since the likelihood of a large magnitude release is small (see Section 3.13.4.2 of the EIS and Consolidated Response SAF-1), it is highly unlikely that the overall integrity of the NHPAQ system would be threatened in the event of a release from the proposed Project.

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. The 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. However, three dimensional transmissivity may differ. For instance, hydraulic conductivity in the Sand Hills topographic region near the top of a dune may be higher than in nearby lowlands or lakes. Other differences between the two sites likely include saturated thickness and potential influence of well pumping on hydraulic gradient. On a localized basis, it is acknowledged that water withdrawals through extensive pumping can influence the hydraulic gradient. While the two sites are not completely analogous, the Bemidji site provides the best physical model for response to an oil release in the NHPAQ system and studies of the Bemidji site suggest that a spill of similar magnitude in the Sand Hills would remain localized and the dimensions of the liquid plume and associated dissolved plumes would be similar in extent to the plumes at the Bemidji site.

Experience with oil spill cleanup therefore suggests that while short- to long- term impacts to the aquifer system in the immediate area of the spill site would likely occur, these impacts would be localized in nature and would be mitigated by appropriate and timely spill response with required regulatory oversight (see Section 3.13. 6.3 of the EIS and Consolidated Response AQF-3).

Consolidated Response AQF-2:
Concerns Regarding Pipeline Alignment through Shallow Aquifers

Several commenters have expressed concern that the pipeline would in some areas intersect shallow aquifers (including the NHPAQ system, particularly the Sand Hills Unit), leading to increased corrosion risk.

Corrosion in an aqueous environment is an electro-chemical process that involves the transfer of electrons between a metal surface (e.g., unprotected steel pipe) and an aqueous electrolyte solution (e.g., groundwater). To address the commenters concerns, the information provided below describes shallow groundwater areas where the proposed Project pipeline could intersect shallow groundwater and also addresses measures that would be incorporated into the proposed Project to reduce corrosion risk.

There are many areas along the proposed Project corridor both within and external to Nebraska where the pipeline may encounter shallow groundwater, and other areas where the pipeline would be installed in wetlands. Many pipelines in the U.S. have been installed pipelines in areas of shallow groundwater and in wetlands.

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.

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.

Additionally, a similar evaluation on groundwater occurrence and depth to groundwater by state using publically available and searchable databases has been evaluated for Montana, South Dakota, Oklahoma, and Texas (see Figures 3.3.1-1, 3.3.1-2, 3.3.1-4, and 3.3.1-5 in the EIS).

Relative to corrosion risk, the proposed Project would include multiple safeguards consistent with industry standards, regulatory requirements in 49 CFR 195, and the 57 Project-specific Special Conditions that Keystone has agreed to implement (see Section 2.3, 3.13.1.1 and Appendix U of the EIS), including:

- Use of high performance Fusion Bonded Epoxy (FBE) external coating;
- Use of abrasion-resistant coatings for trenchless installation;
- Temperature monitoring and management along the pipeline and at pump stations in order to prevent potential coating damage;
- Installation of a cathodic protection (CP) system and an initial CP survey within 6 months of being placed in service. Additionally, a close interval survey will be performed within 1 year of placing the pipeline in-service and these data will be integrated with in-line inspection data;
- Implementation of alternating current and direct current control program when paralleling high voltage power lines; and
- Conducting high-resolution magnetic flux leakage (MFL) in-line inspections (ILI) as a baseline integrity assessment, within 3 years of the in-service date, and on a periodic reassessment schedule that meets or exceeds federal requirements.

DOS, in consultation with PHMSA, has determined that 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. See also Consolidated Response AQF-1. Relative to corrosion risks resulting from crude oil composition, see Consolidated Response OIL-4.

Consolidated Response AQF-3:
Concerns Regarding Potential Contaminant Migration and Spill Response

Many commenters have expressed concern regarding the potential for contaminant migration into aquifers in the event of a spill or release and have also expressed concern regarding how the potential spill and releases would be responded to, cleaned up, and remediated.

An in-depth discussion of the potential effects of oil spills to surface water and groundwater is presented in Section 3.13.6.3 of the EIS. As described in that section and as further discussed below, the extent of potential vertical migration of crude oil to ground water is influenced by several factors including the magnitude of the spill, the viscosity of the crude oil, the density of the crude oil, the characteristics of the environment into which the oil is released (particularly the characteristics of the underlying soils), and the depth to first groundwater. In all cases, the extent of spill migration can be mitigated by quick emergency response measures that include rapid source control (containment and collection of the oil released). See Section 3.13.5.5 of the EIS.

Subsurface Soil and Aquifer Characteristics

The type of soil that overlies the Northern High Plains Aquifer (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.

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 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 (benzene, toluene, ethylene, and xylene [BTEX]) was 132 feet, and approximately 75 percent of these plumes were less than 200 feet long (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 of soils (the rate that water moves through soil) 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 a personal 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 above, 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).

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 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 of the EIS). 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.

Some potential differences between the Bemidji site and the NHPAQ include the source of the sediments. In Bemidji the soils were derived from glacial outwash channels whereas the NHPAQ sediments were derived from alluvial channels and windblown sediments. In addition, the variation in hydraulic conductivity in both the Bemidji site and the NHPAQ may vary on different scales. For instance, in the Sand Hills the hydraulic conductivity at the top of a dune may be higher than near lowlands, near lakes. Despite the differences the range of hydraulic conductivities at both the Bemidji and NHPAQ sites are similar, as such, the Bemidji site provides the best physical model for response to an oil spill in the NHPAQ.

Response Time, Source Control, Cleanup and Remediation

Rapid response is important relative to source control, containment, and cleanup in the event of an oil spill in shallow aquifer areas. In response to a DOS data request, Keystone presented their approach to spill response under two hypothetical spill scenarios defined by DOS. The two scenarios presented to Keystone and their response to these scenarios provides an opportunity to review the level of preparedness and foresight currently in place relative to potential spills.

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 below ground surface), 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 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, the likelihood of groundwater contamination was determined to be minimal. For the second scenario, it was concluded that emergency response teams would have the necessary time to respond prior to the released oil reaching groundwater at 25 feet below ground surface. Impacted groundwater would be remediated by mechanical approaches (excavation and vacuum methods), chemical methods (chemical oxidation) biological methods (bioremediation), and natural attenuation. In most spill scenarios a combination of methods are used to accomplish the highest degree of remediation possible in the shortest amount of time (Keystone 2010, EIS Appendix H). However, DOS acknowledges that in areas such as the Sand Hills where groundwater may be very shallow (less than 10 feet below ground surface), some level of groundwater impact would likely occur even with very rapid and efficient spill response.

PHMSA requires that pipeline operators prepare and abide by two written emergency plans for responding to emergencies on their systems a Pipeline Spill Response Plan (PSRP) and an Emergency Response Plan (ERP). Keystone would submit the PSRP to PHMSA prior to the initiation of proposed Project operations in accordance with the requirements of 49 CFR 194. The PSRP would describe how spills would be responded to in the event of a release from the proposed Project resulting from any cause (e.g., corrosion, third-party damage, natural hazards, materials defects, hydraulic surge). The plan would address the maximum spill scenario and the procedures that would be in place to deal with the maximum spill. The PSRP requires PHMSA review and approval; however, there is a 2-year grace period under which operations can proceed, thus allowing PHMSA time to review the document in light of as built Project conditions and to require incorporation of any needed changes to ensure system safety prior to PHMSA approval.

As required by 49 CFR 195.40, Keystone would also prepare the ERP as part of a manual of written procedures for conducting normal operations and maintenance activities and handling abnormal operations and emergencies. This manual would be reviewed by PHMSA at intervals not exceeding 15 months, but at least once each calendar year, and appropriate changes would be made as necessary to ensure that the manual is effective. This manual would be prepared before initial operations of the proposed Project and appropriate sections would be kept at locations where operations and maintenance activities are conducted.

Consolidated Response AQF-4:
Concerns Regarding Appropriate Land Use in Northern High Plains Aquifer System Area

Several commenters have suggested that water in the Northern High Plains Aquifer (NHPAQ) system is pristine, and therefore no pipeline development should be considered that crosses the aquifer system.

Section 3.3 of the EIS provides information on water quality in the NHPAQ system. While the NHPAQ system is suitable as a source of drinking and irrigation water, in some shallow groundwater areas where crop irrigation occurs, 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 (USGS SIR 2006-5138).

In addition to farming, there are other current land uses in areas overlying the NHPAQ system that could represent past or present contaminant sources. Major existing pipelines overlie the NHPAQ system in Nebraska, including crude oil pipelines (e.g. Kinder Morgan’s Express Platte Pipeline and TransCanada’s Keystone Mainline Pipeline) and oil products and ammonia pipelines (e.g., the NuStar pipeline and Magellan Pipeline Company’s ammonia and petroleum pipelines (see Figure 3.3.1-3 of the EIS). These crude oil and petroleum products pipelines amount to approximately 1,160 miles of pipelines crossing the NHPAQ in Nebraska.

Other past or present potential sources of oil or petroleum product releases in areas overlying the NHPAQ in Nebraska include underground storage tanks (USTs). Many of these USTs are old and are known to have leaked in the past. Past releases are indicators of the degree to which potential oil contamination could impact the NHPAQ system, particularly when these releases have occurred in the general vicinity of the proposed Project. The number of facilities where leaking USTs have been reported in the Nebraska counties that would be crossed by the proposed Project (Nebraska Department of Environmental Quality [NEDEQ] 2010) are summarized below:

County	Number of Reported Number Number of Leaky USTs
Keya Paha	7
Rock	15
Holt	83
Garfield	14
Wheeler	15
Greeley	23
Boone	40
Nance	23
Merrick	52
Hamilton	62
York	85
Fillmore	60
Saline	61
Jefferson	57

Source: NEDEQ 2010.

Although the amount of oil released from these USTs in aggregate is not known, the overall water quality in the counties remains high. Four of the reported UST releases are located within 1 mile of the proposed Project ROW.

Data from the NEDEQ indicate that there have been over 17,000 recorded spills in Nebraska involving petroleum products since 1989. Where impacts to groundwater have occurred as a result of these past spills, the impacts have been localized. Over 50 percent of these spills were caused by leaking USTs, and UST bottoms are typically at depths similar to that of the proposed pipeline (bottom invert 7 to 8 feet below grade). NEDEQ data indicate that despite the long history and significant mileage of pipelines in Nebraska, less than two percent of the recorded spills originated from existing pipelines. Releases from vehicles account for 12 percent of these recorded spills and releases from railroads account for 6 percent (Keystone 2010; PHMSA Docket Number 2008-0285).

Despite previous oil and oil product related spills that may have impacted the NHPAQ system, overall water quality of the aquifer system is acceptable for drinking water and irrigation purposes. Therefore in response to concerns related to potential oil spill impacts to the NHPAQ system, DOS assessed alternative routes that would either reduce or eliminate crossing units of the NHPAQ system, particularly the Sand Hills Unit. See Section 4.3.3 of the EIS and Consolidated Response ALT-1.

Consolidated Response AQF-5: Concerns Regarding Potential Threats to Aquifers from Terrorism and Natural Disaster

Commenters expressed concerns regarding the potential for terrorism and natural disasters that could pose a threat to aquifer groundwater.

A buried pipeline provides a relatively secure transportation corridor compared to other potential transportation methods (e.g., trucks, railways, or ships). The proposed Project corridor does not cross any mapped geologic fault segments with documented surface offset or that are known to be active tectonic faults (see Section 3.1.4 of the EIS). Additionally, the buried pipeline would be resistant to the effects of ground shaking associated with a major earthquake from a distant epicenter or minor earthquakes from a nearby epicenter.

Information on the threat of terrorism to the proposed Project is presented in Consolidated Response TER-1.

Consolidated Response AQF-6: Concerns Regarding Aquifer Protection

Several commenters have suggested that the proposed Project should be constructed as a double-walled or triple-walled pipeline to protect the aquifer.

A double- or triple-walled pipeline would be impractical to construct and is not required to meet federal or state regulations regarding pipeline safety. For information on applicable design and safety measures that would apply for the design, construction, operation, monitoring, maintenance, and inspection of the proposed Project, see Section 2.3 of the EIS and Consolidated Response SAF-1.

Consolidated Response CAN-1: Concerns Regarding Oil Sands Production with and without the Proposed Project

Many commenters expressed concern regarding the link between implementation of the proposed Project and environmental impacts in Canada from expanded development of the Alberta oil sands.

Proposed Keystone XL Pipeline Effect on Oil Sands Production

As discussed in Section 4.1.2 of the EIS, the proposed Project would not be the only crude oil transportation link between Alberta and the United States. There are already pipelines that transport Western Canadian Sedimentary Basin (WCSB) crude oil to U.S. markets as well as tanker shipping links from WCSB to U.S. ports. Additionally, there are other proposed cross-border pipelines and existing alternative forms of bulk transport (e.g., rail networks, truck transport, and barges) that could transport WCSB crude oil into the U.S. EnSys (2010) performed an analysis that 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, resulting in 14 separate scenarios. The two demand projections 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” and the Reference Case from the 2010 EIA Annual Energy Outlook. The EnSys (2010) projections indicate that approval or denial of the proposed Project would have little if any effect on the rate of development in the Canadian oil sands between now and 2030, and further indicates that the rate of oil sands resource development would only be affected if no additional transportation infrastructure is constructed either now or in the future to allow international access to WCSB oil sands resources.

A specific finding of the EnSys (2010) report is as follows: “The only scenario studied that resulted in a significant reduction of WCSB oil sands production assumed (a) a total moratorium on WCSB pipeline expansions in Canada to any destination, and (b) no expansion of pipeline capacity between PADD2 and PADD3, and (c) restriction of rail/barge modes. Even then, existing available pipeline capacity (up to and including Keystone Mainline and Extension – but not KXL) is such that any reduction in WCSB production would not occur until after 2020 (Figures 1-4 and 1-5).” The scenario referenced above is the so-called No Expansion Scenario, a scenario that the EnSys report concluded was highly unlikely: “...the No Expansion scenario explores extreme market conditions based on input assumptions that would have a relatively low probability of occurring. The potential for producers to avoid curtailment by using other proven transport modes that would become more cost-effective for delivery of WCSB crude under a scenario where there was no pipeline expansion, renders the No Expansion scenario still less probable." Extensive analysis of crude-oil market dynamics and several modes of bulk transportation indicate that a "No Expansion" scenario where all modes of bulk transport for crude oil out of the WCSB remain at 2010 levels through 2030 is highly implausible.

Canadian producers are actively seeking to develop alternative crude oil markets worldwide. They are making efforts to market the oil to other countries using transport via pipeline to either the west or east coast of Canada, and from those locations by tanker to other countries. Other countries that are likely to consume crude oil from Canada are primarily located in Asia; those nations are experiencing increased demand for crude oil and are currently heavily dependent on OPEC for their supplies. Various pipeline projects have been proposed to transport crude oil from Alberta to the Canadian west coast (see Sections 1.4 and 4.1 of the EIS). For one of those planned pipelines, the Enbridge Northern Gateway Pipeline, a Chinese oil firm is among a group of investors providing early-stage funding for the project (described in Section 4.1.2.2 of the EIS). The consortium is expected to invest approximately $100 million (Canadian) to fund the regulatory and development costs of the $5.5 billion (Canadian) project. Consortium members would also get guaranteed space on the pipeline and the right to take an equity stake.

Extraterritorial Environmental Concerns

Canadian federal and provincial authorities have the sovereign authority over approving or denying crude extraction activities under their jurisdiction. This authority includes reviewing the potential environmental impacts of projects in Canada. The oil sands deposits that serve as the source for most of the crude oil that would be transported through the proposed Project are in the province of Alberta. Therefore, under Canadian law Alberta provincial authorities have primary responsibility for review of these projects, including associated processing facilities. Nonetheless, given agency and public concerns expressed in comments received on the draft EIS and supplemental draft EIS, and for the decision-maker's information, DOS has decided as a matter of policy to include 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. Section 3.14.4 of the has been expanded to address (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. For additional information on extraterritorial environmental concerns and GHG emissions associated with the production, refining and consumption of WCSB crude oil-derived transportation fuels, see Section 3.14.3 of the EIS and Consolidated Responses GHG-2 and GHG-4.

Consolidated Response CMT-1: Concerns Regarding the Length of the Comment Periods

DOS received comments expressing concern regarding the length of the comment periods for the draft EIS and the supplemental draft EIS.

Draft EIS

In compliance with the Council on Environmental Quality (CEQ) regulations for implementing NEPA, DOS announced a 45-day comment period for the draft EIS in the Notice of Availability (NOA) for the draft EIS. The comment period was scheduled to end on May 31, 2010. Prior to the scheduled close of the comment period, DOS received requests for an additional comment period extension and extended the comment period to June 16, 2010. In order to accommodate two additional draft EIS comment meetings near Houston, Texas and in Washington, D.C., DOS again extended the draft EIS comment period. The comment period officially closed on July 2, 2010.

Supplemental Draft EIS

In the Notice of Availability for the supplemental draft EIS, DOS stated that there would be a 45-day review period for the document. Many commenters requested that DOS extend that to a 120-day review period. The 45-day review period complies with the CEQ regulations for implementing NEPA, and DOS has not extended the review period. Parts of the analysis provided in the supplemental draft EIS relied on the EnSys Report (2010). The EnSys report was made publicly available on the DOS Keystone XL website as of January 31, 2011 and its availability was noticed in the Federal Registers (76 FR 8396) on February 14, 2011. It was also included as an appendix to the SDEIS. The report was therefore available for public review and comment for over four months prior to the close of the SDEIS comment period.

In addition, there will be an additional 30-day public comment period after the final EIS is issued and before the Record of Decision and the National Interest Determination are issued.

Consolidated Response CMT-2: Concerns Regarding the Number and Location of Public Comment Meetings and Requests for More Public Involvement

Many commenters expressed concern about the number and location of public comment meetings for the draft EIS. DOS also received comments requesting that public comment meetings be conducted for the supplemental draft EIS.

Draft EIS

DOS initially scheduled and conducted 19 public comment meetings at locations in six states in the vicinity of the proposed pipeline route. Based on public interest, DOS then scheduled and conducted two additional public comment meetings in the Houston, Texas area and in Washington, DC. While DOS understands the considerable public interest and concern related to the proposed Project, DOS considers the number of comment meetings held and the locations of the meetings to be consistent with the Council on Environmental Quality (CEQ) regulations for implementing NEPA. In addition, public comments on the proposed Project were also received through the DOS Keystone XL Project website, through emails and voicemails to the DOS Project Manager, and through letters and faxes. DOS considers the written comments received, along with the comments received at the public comment meetings, sufficient to obtain an understanding of the general and specific concerns and interests of the public.

Supplemental Draft EIS

DOS received more than 280,000 public comment letters on the supplemental draft EIS through the DOS Keystone XL Project website, and through e-mails, U.S. mail, and faxes to the addresses specified in the Notice of Availability for the supplemental draft EIS and in the supplemental draft EIS. Each separate comment in the comment letters was considered in the preparation of the final EIS and responded to in the final EIS (see Appendix A, Parts A-2 and A-4). DOS considered those comments to be of equal importance to any comments that would have been presented verbally at public comment meetings. As a result, DOS considers that the comments received on the supplemental draft EIS adequately identify the general and specific concerns and interests of the public.

During September 2011, DOS will also host public meetings in each of the six states through which the proposed pipeline would pass. The meetings will be held in the state capitals of Montana, South Dakota, Nebraska, Kansas, Oklahoma, and Texas, with an additional meeting in the Sand Hills region in Nebraska and along the Gulf Coast near Port Arthur, Texas. This will be followed by a final public meeting in Washington, DC. These meetings will provide an opportunity to voice views on whether granting or denying a Presidential Permit for the pipeline would be in the national interest and to comment on economic, energy security, environmental and safety issues relevant to that determination.

Consolidated Response CMT-3:
Concerns Regarding the Level of Information Provided to the Public on the Proposed Project and the Scoping Meeting Locations and Schedules

Many commenters expressed concern that they had not received sufficient information regarding the proposed Project. Other commenters expressed concern that they had not received notification of the locations of and schedule for the scoping meetings for the draft EIS.

DOS published its Notice of Intent (NOI) to prepare an EIS on January 28, 2009, including the location and schedule for the initially planned 20 scoping meetings in 6 states in the vicinity of the proposed pipeline route. Scoping meetings were conducted in February, March, and April 2009. The NOI, included a description of the proposed Project, was published in the Federal Register, and copies were distributed to local newspapers and television and radio stations. Additionally, announcements of the scoping meetings were placed in local newspapers. DOS constructed a publically accessible website for the proposed Project and posted the Application for Presidential Permit, including a detailed Project description that included map sheets showing the proposed alignment on that website. DOS considers its scoping and public notification concerning the proposed Project to be consistent with the Council on Environmental Quality regulations for implementing NEPA. Responses to comments regarding the NOI are addressed in Consolidated Response INT-1.

Consolidated Response CMT-4:
Requests for Draft DEIS Comment Meetings Near Houston, Texas and in Washington, D.C.

Some commenters requested additional comment meetings on the draft EIS in the Houston area and in Washington D.C.

DOS initially scheduled and conducted comment meetings in the vicinity of the proposed pipeline corridor in Beaumont and Liberty, Texas, both of which are east of Houston. Based on public concern, DOS scheduled and conducted a comment meeting in Channelview, Texas, which is essentially adjacent to the eastern city limits of Houston, and scheduled and conducted a comment meeting in Washington, D.C. to provide an opportunity for stakeholders who are distant from the proposed pipeline corridor to comment on the draft EIs and the proposed Project.

Consolidated Response CMT-5:
Concerns that Scoping and the Draft EIS Did Not Identify All State and Federal Activities and Agencies Involved

Many commenters expressed concern that all state and federal activities and agencies that could be involved in review of the proposed Project were not identified through scoping or in the draft EIS.

The Notice of Intent (NOI) for the draft EIS identified the key agencies that would be involved in the environmental analysis, including ensuring compliance with Section 106 of the national Historic

Preservation Act. The scoping period for the draft EIS was used to identify key issues to be addressed in the EIS, which in turn resulted in other federal agency involvement in the NEPA environmental review process. Section 1.5 of the EIS lists the federal agencies that served as either cooperating or assisting agencies as well as the federal actions those agencies would be responsible for. Table 1.10-1 of the EIS lists the federal permits and authorizations that would be required for the proposed Project to be constructed, operated, maintained, and monitored. In addition, federal permits and authorizations and the agencies involved are addressed in the relevant resource sections of Section 3.0 of the EIS.

Consolidated Response CMT-6:
Concerns That Not Enough Paper Copies of the Draft EIS Were Available

Several commenters have expressed concern that not enough paper copies of the draft EIS were made available.

Paper copies and CDs of the draft EIS were provided to landowners and stakeholders as requested and were also made available at local libraries along the route. An electronic version was posted on the DOS Project website. DOS attempts to minimize the number of paper copies of the DEIS that are distributed to be consistent with overall federal environmental sustainability goals. However, all stakeholders who specifically requested paper copies rather than CDs were accommodated.

Consolidated Response CST-1:
Requests to Construct the Pipeline Aboveground

Several commenters have recommended that the pipeline be constructed above ground.

While is it technically feasible to construct the proposed Project aboveground in some 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, extreme weather events (e.g., tornados and hurricanes) and the effects of other outside forces, such as vehicle collisions. For example, in 2001, the Alyeska Pipeline was punctured by a bullet fired from a hunting rifle and about 300,000 gallons of crude oil was released into the environment. 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 to the pipeline system.

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. Pipelines are sometimes constructed aboveground at active fault crossings to allow the pipeline to move laterally, thus reducing or eliminating direct shear on the pipeline. However, the proposed Project corridor does not cross any mapped geologic fault segments with documented surface offset or that are known to be active tectonic faults.

Nearly all petrochemical transmission pipelines in the U.S. are buried, and Keystone has proposed to bury the proposed Project pipeline. Keystone would be required to construct, operate, maintain, inspect, and monitor the Project in compliance with the requirements of the Pipeline and Hazardous Materials safety Administration (PHMSA) presented in 49 CFR 195, relevant industry standards, and applicable state standards. In addition, Keystone agreed to comply with the 57 Project-specific Special Conditions developed by PHMSA (see Consolidated Response SAF-1 and Appendix U of the EIS) and to 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.

DOS, in consultation with PHMSA, has determined that 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.

The EIS has been revised to address the alternative of an aboveground pipeline (see Section 4.4 of the EIS).

Consolidated Response CUL-1:
Concerns Regarding the Protection of Historic Properties and Consultation Under Section 106 of the National Historic Preservation Act

Many commenters expressed concern relating to the protection of historic properties and the Section 106 consultation process.

DOS has conducted its compliance with the requirements of the National Historic Preservation Act in accordance with 36 CFR 800.6 regulations to identify, evaluate and develop mitigation for historic properties including properties of religious and cultural significance that may be affected by the proposed Project. As part of its compliance activities DOS communicated with over 100 Indian tribes, of which 45 federally recognized Indian tribes agreed to participate as consulting parties in the Section 106 process. In addition, 19 state and federal agencies have participated as consulting parties including the Advisory Council on Historic Preservation (ACHP). DOS continues to consult with those tribes and agencies that elected to become consulting parties for the proposed Project. A Programmatic Agreement (PA) was developed with the consulting parties that addresses potential effects to historic properties that could occur during Project construction and operation (see Appendix S of the EIS). The PA also includes Treatment Plans for those historic properties that DOS determines are eligible for the National Register of Historic Places and that would be adversely affected by the proposed Project. For more information on the Section 106 process see Section 3.11 of the EIS.

Consolidated Response DEC-1:
Concerns Regarding the Life of the Proposed Project and Decommissioning of the Proposed Project

Commenters have asked for additional information about the anticipated life of the proposed Project and have expressed concern that the EIS does not provide a description of how the proposed Project would be decommissioned at the end of its useful life. This response and Section 2.6.2 of the EIS provide information regarding those comments.

Project Life

The design life used by Keystone to develop the engineering standards for the proposed pipeline system is 50 years. However, with pipeline integrity management and implementation of an operations and maintenance program, 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.

Decommissioning

Federal requirements that apply to the decommissioning of crude oil pipelines are contained in the regulations of the Pipeline and Hazardous Materials Safety Administration (PHMSA) at 49 CFR 195.402(c)(10) and 40 CFR 195.59. 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 (40 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." (40 CFR 195.59 (Abandonment or deactivation of facilities)).

Keystone would adopt operating procedures to address these requirements for the proposed Project as they have for previous pipeline projects including the existing Keystone Oil Pipeline. Keystone 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 would traverse federal land under the management and jurisdiction of the BLM, with the majority of the federal land in Montana. The portion of the proposed Project that would cross BLM-administered land would be subject to the pipeline decommissioning and abandonment requirements itemized in the BLM right-of-way stipulations. 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 pretermination 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."

The right-of-way (ROW) grant on federal lands under the management of BLM for the proposed Project would have a maximum term not to exceed of 30 years. For the proposed Project to extend beyond 30 years, the approved ROW grant would require a renewal authorization-certification decision by BLM. This decision would be considered a federal action subject to the requirements of NEPA. As a result, a decision to renew-certify the ROW grant to allow the proposed Project lifetime to remain in place beyond 30 years would be accompanied by an environmental analysis similar to the analysis required for the initial ROW grant. This process occurred on the Alyeska Oil Pipeline in Alaska. The initial ROW grant for federal lands crossed by that project extended from 1974 to 2004, and BLM and the State of Alaska through the Joint Pipeline Office required an EIS addressing continued operation of that project prior to certifying a new ROW grant with a maximum term of 30 years. It is likely that the future environmental assessment that would be required by BLM to renew-certify the approved ROW agreement grant for the proposed Project would include a review of the environmental effects of the continued operation of the entire proposed Project, since operations on non-federal lands would be connected actions to the renewal-certification action on federal lands. Therefore, any operations or decommissioning that would occur beyond the initial 30-year ROW grant would be subject to extensive federal environmental review.

In Texas, Section 111.025 of the Texas Natural Resources Code would apply to the abandonment 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."

The Montana Department of Environmental Quality proposed a stipulation under the Montana Major Facility Siting Act (MFSA) that would require Keystone to submit a decommissioning plan 1 year prior to the anticipated date for decommissioning of the certificated facility. MDEQ would also require that if the method of decommissioning required under federal law results in ground disturbing activities, the current owner would be responsible to MDEQ for complying with reclamation and environmental protection standards established at the time of Project certification. The proposed requirement is presented at Appendix I, Attachment 1, Section 5, of the EIS. There are no state regulations applicable to pipeline abandonment in South Dakota, Nebraska, or Oklahoma.

As stated in Section 2.6 of the EIS, Keystone would comply with all regulatory requirements in place at the time of decommissioning. Since regulations at the federal, state, and local level change over time, it is highly speculative what the regulatory framework that would apply to pipeline decommissioning may be at the end of the useful life of the proposed Project over 50 years in the future.

Prior to decommissioning the proposed Project, Keystone would identify the decommissioning procedures it would use along each portion of the route. Keystone would also 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 right-of-way (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.

The 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.

A response to comments requesting that Keystone be required to post a bond for the costs of decommissioning is presented in Response LIA-2.

Consolidated Response EAS-1: Concerns Regarding Pipeline Routing in Montana

Many commenters expressed concern about the proposed route and potential “reroutes” or variations of the route in Montana.

During the National Environmental Policy Act (NEPA) environmental review process, DOS considered many alternative pipeline routes, including alternative routes in Montana. Based on those considerations, DOS determined that the proposed route (Alternative SCS-B) was the most appropriate route through Montana (see Section 4.3.3 of the EIS).

As described in Section 4.3.7 and in Appendix I of the EIS, Keystone applied to the State of Montana for a Certificate of Compliance under the Montana Major Facility Siting Act (MFSA) that is administered by the Montana Department of Environmental Quality (MDEQ). In considering the application, MDEQ also reviewed alternatives to the proposed route and “variations” to the proposed route in Montana. Variations are relatively short deviations from a proposed route that are developed to address state agency concerns and requirements or to resolve or reduce construction impacts or landowner concerns relative to localized, specific resources such as cultural resource sites, wetlands, recreational lands, residences, site improvements 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 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 have been submitted by concerned landowners.

As reported in Appendix I of the draft EIS, MDEQ initially identified 19 variations in Montana and preliminarily selected nine of those variations as preferable to the segments of the proposed route (Alternative SCS-B) that they would replace. During the comment period for the draft EIS, MDEQ and Keystone worked with landowners to develop several more variations and assessed those in comparison to the proposed route and the variations preliminarily selected in the draft EIS. After the end of the comment period, MDEQ continued to work with landowners, Keystone, and the Bureau of Land Management (BLM) to assess the impacts of those variations and to identify other potential variations. As result of that work, MDEQ identified a total of 50 variations, ranging in length from about 0.2 mile to about 42.0 miles. In addition, Keystone identified a total of 48 minor realignments ranging in length from approximately 1,000 feet to 4 miles. Section I-2.4 provides information on the variations and realignments considered by MDEQ, including the agency’s preferred route.

The variations selected by MDEQ and included within the MFSA Certificate of Compliance would replace short segments of the overall proposed Project in Montana, are relatively close to the proposed route (Alternative SCS-B) in Montana, address specific issues relevant to MDEQ, and have been reviewed in detail by MDEQ under MFSA and the Montana Environmental Policy Act, which has requirements similar to those of NEPA. BLM has concurred on selected route variations that would cross federal lands. In addition, both DOS and MDEQ have conducted the appropriate environmental reviews of the proposed Project route through Montana (Alternative SCS-B) as reported in this EIS, including in Appendix I.

Consolidated Response EAS-2: Concerns Regarding Easement Negotiations, Eminent Domain Proceedings, and Enforcement of Easement Agreements

Several commenters have expressed concern about the negotiation process for easement agreements along the proposed route and the use of eminent domain for the procurement of some easements. Commenters have also suggested that since TransCanada is a Canadian company, it should not be allowed to use the eminent domain process to obtain easements. In addition, some commenters have expressed concern about their options if Keystone does not comply with easement agreements. Those issues are addressed below.

Corporate Status of Keystone

As noted in Section 1.0, TransCanada-Keystone Pipeline LP (Keystone) is not a foreign corporation. It is a limited partnership organized under the laws of the state of Delaware. Keystone is the entity that would construct the Project if it is approved, is a common carrier, and is therefore eligible to use eminent domain laws if easements cannot be successfully negotiated with landowners.

Easement Negotiations

To construct, operate, and maintain the proposed Project, Keystone would need the rights to easements (or rights-of-way) along the entire proposed route. Keystone is responsible for negotiating easement agreements with landowners along the route in each state. The easement agreements would list the conditions that both the landowner and Keystone agree to, including financial compensation to the landowners in return for granting easements. Compensation would also be made for loss of use during construction, crop loss, loss of non-renewable or other resources, and restoration of any unavoidable damage to personal property during construction. DOS expects Keystone to negotiate fairly, honestly, and respectfully with landowners when they negotiate an easement. However, those negotiations and final agreements are private business concerns between the landowners and Keystone, and DOS has no legal authority to intervene in the proceedings. At the time the final EIS was prepared, Keystone reported that it had successfully negotiated easement agreements with approximately 83 percent of the landowners along the proposed route.

Eminent Domain

State laws dictate under what circumstances eminent domain may be used and define the eminent domain process within the state. If an easement negotiation cannot be completed in a manner suitable to the landowner and Keystone, Keystone would use state eminent domain laws to obtain easements needed for pipeline construction, operation, maintenance, and monitoring. The level of compensation would be determined by a court according to applicable state law. DOS has no legal authority to intervene in eminent domain proceedings. In addition, eminent domain does not apply to land under federal ownership or management.

Violation of Stipulations in Easement Agreements

State or local trespass and access laws are applicable along the entire route and therefore along each easement negotiated by Keystone and the landowner or obtained by Keystone through the eminent domain process. As noted above, DOS has no legal authority related to Keystone's easement negotiations nor does it have the legal authority to enforce the conditions of an easement agreement. A landowner who considers Keystone to be out of compliance with an easement agreement would have take up the matter with Keystone or local law enforcement officials, or initiate legal consultation.

Consolidated Response ECO-1: Concerns Regarding Potential Beneficial Socioeconomic Impacts

Many commenters stated that the proposed Project would provide many higher-waged construction jobs as well as economic benefits associated with the manufacturing and purchasing of pipe, equipment, and construction materials as described in the Perryman Group study commissioned by TransCanada (June 2010).

The EIS provides a description and an analysis of the number of construction jobs that would be created by the proposed Project, as well as the associated economic activity that would be generated by the estimated $7 billion Project (see Section 3.10 of the EIS). The TransCanada/Perryman Group study provides additional information about the economic benefits of the Project, but the results are different from those presented in the EIS for several reasons. First, the EIS uses a 50-year Project life whereas the Perryman study used a 100-year Project life. Also, it is not clear whether Perryman's calculation of the multiplier impacts (indirect and induced) of construction in the study is based upon the 3-year construction period or the assumed 100-year life of the proposed Project. The numbers presented in the Perryman study included direct construction expenditures as well as multiplier (indirect and induced) effects.

Additionally, the EIS describes the employment benefits in terms of the number of jobs generated whereas the Perryman study provided estimates of person-years of employment (i.e., the number of jobs multiplied by the projected Project life [100 years]). The EIS states that a total of 5,000 to 6,000 workers would be employed during the construction phase of the Project (see Page 3.10-56), comprised of 500 to 600 workers per construction spread. Out of these, an estimated 10 to 15 percent (500 to 900) would be hired locally. The unit of measure used in the EIS can be compared to the number of unemployed or underemployed people and can also be compared to the immediate job needs within a particular jurisdiction. It therefore provides a convenient base of comparison between the affected environment and potential Project impacts. Many commenters misinterpreted the person years calculated within the Perryman report and overestimated the number of jobs that would be created by the proposed Project.

As noted by the Dow Jones Newswires on September 14, 2010, many of the jobs created by construction of the Project would be filled with union employees. As of that date, six unions had signed a Project Labor Agreement with TransCanada, including:

- Laborers International Union of North American;
- International Brotherhood of Teamsters;
- AFL-CIO;
- United Association of Journeymen and Apprentices of the Plumbing and Pipefitting Industry of the United States and Canada;
- Internal Union of Operating Engineers;
- Pipeline Contractors Association.

The EIS analysis assumes that the crude oil transported by the proposed Project would replace dwindling and/or less reliable supplies from Venezuela and Mexico. As a result, the analysis in the EIS assumes there would be limited additional economic benefit related to PADD III refining. In contrast, the Perryman study considers economic activity associated with the refining of crude oil and the sales of refined products as a direct benefit of the proposed Project. The refining activity in PADD III projected out to at least 2030 would occur with or without the proposed Project (EnSys 2010). If the proposed Project is not available, PADD III refiners would find alternative sources of crude oil. The EIS therefore does not consider economic activity in PADD III associated with refining to be an economic benefit attributable to the proposed Project.

Consolidated Response ELE-1: Concerns Regarding the Source of Electrical Power for Pump Stations

Several Montana residents expressed concern about the source of energy for the electricity provided by utility companies to power the pump stations and mainline valves in Montana. Some Montana residents also asked about the potential for residential rates to increase.

The Montana Consumer Counsel prepared a report entitled "Draft, Keystone XL Pipeline Rate Impact Study" to address rate and source issues. The report, which is available at http://deq.mt.gov/MFS/KeystoneXL/KeystoneXLIndex.mcpx, makes the following conclusions:

> "Service to the Keystone pump stations represents a significant increase in load, as well as a significant investment compared with current plant in service, for each of the four Montana electric coops that will serve them. However, the coops, and their suppliers, are well aware of that fact and have taken careful measures to insulate themselves and their customers from the risk of cost increases due to taking on such sizeable loads. By setting up pass-through rates for wholesale power from Basin Electric, and by security measures to ensure payment of the costs of new transmission and substation investments (and in the case of McCone, by arranging for upfront payment of electric facility construction costs by Keystone) the coops appear to have done a good job of eliminating the risk of cost increases due to service to the pipeline, construction of the electrical infrastructure, or from early termination of pipeline and pump station operation.
>
> "Service to the Keystone Pump Station 14 by MDU does not represent as significant an increase in proportion to existing load as it does for the coops, rather in the order of 12 percent of Montana loads, and the required facility investment is roughly 3 percent of Montana plant in service. Nevertheless, MDU has proceeded in a way that it believes will protect its existing customers from any direct rate impacts from service to the pipeline. It will recover its infrastructure costs through the fixed cost margin on power sales, and will require an irrevocable letter of credit to ensure the revenue flow continues at least long enough to fully recover those costs. Should any unexpected risks emerge, the Montana PSC will have tools at its disposal to protect MDU's other customers, for example by directing MDU to create a separate rate class to recover costs directly from the pipeline. While it has never been done in Montana, in the event of a shutdown the PSC may be able to require a write-off of any incomplete cost recovery of special purpose facilities built to serve the pipeline.
>
> "There could be some long term impacts to the resource portfolio plans of Basin Electric and of MDU, in the form of a need to advance the dates at which new resources are planned to come on line. However, given the size of the pump station loads served relative to the resource portfolios and planned new resources of Basin and MDU, and given the normal uncertainties over load growth and the cost and completion dates of planned facilities, any such impacts should be minor and in fact may not be distinguishable."

In addition, comments received during scoping and during the draft EIS comment period from Big Flat Electric Co-operative in Montana indicate that the introduction of a new customer to the rural electric community will have a strong rate stabilization impact beneficial to all customers in the Big Flat service area. See Section 3.10.4.1 of the EIS for further discussion.

Consolidated Response ENR-1:
Requests for Denial or Approval of the Presidential Permit Application and for Suspending Review of the Proposed Project and Adequacy of the EIS

DOS received numerous comments related to its pending decision on the Keystone XL Presidential Permit application. Some commenters encouraged DOS to reject the Presidential Permit application, some commenters encouraged DOS to suspend the review of the Presidential Permit application, and other commenters encouraged DOS to approve the Presidential Permit application.

As described in Sections 1.0 and 1.5.1 of the EIS, DOS is responsible for reviewing applications for Presidential permits for oil pipelines that cross any international border of the United States. Therefore, when Keystone submitted its application for the proposed Project in September 2008, DOS was obligated to initiate a review of the proposed Project and continue that review until the Secretary decides whether or not to issue a Presidential Permit for the proposed Project and determines whether or not the proposed Project is in the national interest.

The DOS review of the proposed Project consists of conducting (1) an environmental review of the proposed Project consistent with the National Environmental Policy Act (NEPA), and (2) conducting a National Interest Determination (NID) consistent with Executive Order 13337. The environmental review, including preparation of this EIS, has been conducted consistent with the DOS regulations pertaining to NEPA (22 CFR Part 161) as well as the Council on Environmental Quality (CEQ) regulations for implementing NEPA (40 CFR Part 1500) and includes the preparation of this EIS. As a result, DOS considers the EIS to be in full compliance with the requirements of a NEPA environmental review. The NID process is described in Sections 1.3 and 1.5.1 of the EIS and in Consolidated Response P&N-9.

After issuing the final EIS, DOS will complete its review process under EO 13337 to decide whether the proposed Project is in the national interest, and issue a Record of Decision (ROD) under NEPA. Those decisions will be informed by the EIS process. Additionally, the NID will be informed by comments received in public meetings hosted by DOS to be held in each of the six states through which the proposed pipeline would pass. These meetings will occur in the state capitals of Montana, South Dakota, Nebraska, Kansas, Oklahoma, and Texas, with an additional meeting in the Sand Hills region in Nebraska and along the Gulf Coast near Port Arthur, Texas. These meetings will be followed by a final public meeting in Washington, DC. These meetings will provide an opportunity to voice views on whether granting or denying a Presidential Permit for the pipeline would be in the national interest and to comment on economic, energy security, environmental and safety issues relevant to that determination.

Consolidated Response ENV-1:
Concerns Regarding Sensitive and Fragile Environments and Ecosystems

Many commenters were concerned about potential direct and indirect effects of the proposed Project on sensitive and fragile environments and ecosystems.

DOS solicited input from the public, and from federal and state resource management agencies to assist in identifying sensitive and fragile natural resources that would potentially be affected by the proposed Project. Relevant information received on those environments and ecosystems was incorporated into the

EIS along with information available in the scientific literature and information provided in the Presidential Permit application and supplemental information submitted by Keystone as a part of its application. Sections 3.1 through 3.8 of the EIS include assessments of potential impacts of the proposed Project to sensitive and fragile ecosystems and species. In general, potential impacts to these resources were addressed through avoidance where feasible and through mitigation elsewhere, including incorporation of best management practices into the proposed Project. Assessments of potential mitigation measures were based on input from federal and state agencies to avoid, minimize, and mitigate for loss or damage to sensitive and fragile ecosystems. Section 3.13 provides an analysis of the risks of unplanned spills or releases of crude oil, refined oil products, or other hazardous materials during proposed Project construction, normal operations, or abnormal emergencies.

Consolidated Response ENV-2:
Concerns Regarding Pipeline Temperature Effects

Many commenters were concerned about potential effects of heat dissipated from the pipeline on vegetation especially within sensitive environments such as the Sand Hills, native prairie grasses, and on soils, crops, soil microbes, and potential northward migration of invasive plants and animals.

The potential effects of waste heat dissipated from the buried pipeline on soils and vegetation are evaluated in Sections 3.2.2.2, 3.4.3, and 3.5.5 and in Appendix L of the EIS. The winter and summer heat flux from the pipeline was modeled and effects were estimated based on soil temperature profiles along the pipeline route (Appendix L of EIS). Soil surface temperatures are primarily reflective of climate conditions, although minor local increases may be observable during the winter and spring at the northern end of the pipeline as discussed in Sections 3.2.2.2 and 3.5.5.1. The influence of heat flux from the pipeline on soil temperature profiles by season and location along the pipeline route is illustrated in Appendix L of the EIS. Because the Project as currently proposed would operate at a lower pressure and throughput than was assumed in the Appendix L analysis, the analysis is considered to be conservative since the operating temperature of the pipeline under these revised operating parameters would in general be lower than the operating temperature assumed in the analyses.

Seasonally elevated soil surface temperatures may cause early germination, potentially increased production, or decreased soil water due to soil drying and decreased production. Additional discussions of elevated soil temperature effects on native prairie gasses and crops were added to Section 3.5.5.1 of the EIS in response to comments. The potential effects of pipeline temperature on the American burying beetle are described in the Biological Assessment (see Appendix T of the EIS). See also Consolidated Response NOX-1.

Consolidated Response ENV-3:
Concerns Regarding Potential Impacts to Native Grasslands and Prairies

Several commenters were concerned about irreversible impacts to native grasslands or prairies crossed by the proposed Project.

Native grasslands were identified, surveyed, and evaluated for quality along the proposed route wherever access was granted. Grassland quality was evaluated based on grazing and other land uses that could stress grassland quality. The acreage of high-quality native grasslands (defined as grasslands dominated by native grass within large tracts of native grasslands that exhibit relatively high diversity of native grasses and native forbs and very few exotic weeds) that would be crossed by the proposed Project are identified in Section 3.5.5.2 of the EIS. DOS recognizes the need to limit trenching and topsoil disturbance in arid native grassland habitats. Where disturbance does occur within these sensitive areas, restoration seeding recommendations would be designed to mimic native grassland vegetative communities and would be reviewed by Keystone with landowners. Construction damage would be minimized to the extent practicable by incorporating the procedures described in the Keystone Construction, Mitigation, and Reclamation Plan (presented in Appendix B of the EIS). Mitigation and restoration specific to native grasslands, including Sand Hills grasslands, are discussed in Section 3.5.5.2 and Appendix H of the EIS. No remnant or protected prairies were identified along the proposed pipeline corridor during consultations with state and federal resource agencies.

Consolidated Response ENV-4: Concerns Regarding Oil Sands Production and Migratory Birds

Many commenters were concerned about the potential effects of oil sand development, especially surface mining and tailings ponds on migratory bird resources shared by the United States and Canada.

Oil sands projects and oil transportation pipelines are evaluated and permitted by the Canadian federal and provincial (Alberta and Saskatchewan) 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. Canada's 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 oil sands development tailings ponds have been cited as violations of the MBCA and have been prosecuted by the Canadian government.

Bird resources (waterfowl, waterbirds, shorebirds, land birds) are shared on a continental scale. The Tri-National North American Bird Initiative Committee was established to increase cooperation and effectiveness of bird conservation efforts among Canada, the U.S 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. Multinational North American bird conservation plans include: the North American Waterfowl Management Plan, North American Land Bird Conservation Plan, United States and Canadian Shorebird Conservation Plan, Waterbird Conservation for the Americas, North American Grouse Management Strategies, and Northern Bobwhite Conservation Initiative.

As discussed in Section 3.14.4.3 of the EIS, oil sands development alters habitats through land surface alteration including: mine sites, tailings ponds, well sites, industrial roads, pipelines, powerlines, seismic cut lines, and facilities. These land alterations reduce both the amount and the suitability of adjacent habitat available for migratory birds. Project components such as roads and powerlines increase migratory bird collision mortality. Tailings ponds contain residual bitumen and are an exposure risk especially for migratory waterbirds. Alberta's oil sands lease areas cover about 21 percent of the 418,325 square miles of the Boreal Taiga Plains Bird Conservation Region (Government of Alberta – Energy 2010, U.S. NABCI Committee 2000). One hundred seventy migratory birds (49 waterbirds, 121 landbirds) have been recorded on 19 breeding bird survey routes concentrated within the southern portions of the leased area (Sauer et al. 2011, Government of Alberta – Energy 2010). Population trends for 9 of these 49 waterbirds and 29 of these 121 landbirds experienced significant declines within the Boreal Taiga Plains Region from 1999 to 2009; while nearly 70 percent of these birds showed no significant population trends (Sauer et al. 2010). Waterbirds and landbirds of moderate to high conservation concern present in the oil sands lease area based on the breeding bird survey data are listed in Table 3.14.4-1 of the EIS. However, as discussed in Section 4.1.2 and in Consolidated Response

CAN-1, implementation of the proposed Project would not substantially influence the rate or extent of oil sand extraction activities in Canada and therefore, would not substantially alter any impacts to migratory birds associated with oil sands development. See also Consolidated Response WIL-2 for additional information on migratory bird issues.

Consolidated Response ENV-5: Requests for Use of Horizontal Directional Drilling for All Wetlands and Waterbodies

Several commenters questioned why all wetlands and waterbodies would not be crossed using the horizontal directional drilling (HDD) method and are concerned that the least damaging crossing methods would not be employed for construction. Commenters expressed particular concern relative to the open-cut crossing method.

Crossing all wetlands and waterbodies using HDD would not be practicable. Although HDD crossings would be environmentally preferable in some situations, they would not be environmentally preferable in all situations. HDD crossings would require additional work pads and water withdrawals for use in drilling fluids and would also require additional heavy equipment deployment and fuel storage. Spills or leaks of drilling fluids during HDD pipeline installations could occur and would present a risk of temporary water quality degradation with potential impacts to aquatic species. Additionally, there are geologic constraints on the use of HDD methods. For instance, HDD is typically not employed where rock is the underlying geologic material. The HDD method would also not be employed in locations where the composition of soils underlying the streambed could increase the risk of a frac-out (defined as an unplanned or accidental release of HDD drilling fluids to the aquatic environment). For wetland and stream crossings, Keystone would be required to obtain the approval of the U.S. Army Corps of Engineers (USACE) for the specific methods used. As part of this process, USACE would consult with federal and state resource agencies to determine appropriate construction mitigations, including construction schedules and final crossing methods to avoid or minimize impacts. Similarly, any use of the open-cut crossing method would also require the approval of USACE and depending on location could also require the approval of the Bureau of Land Management on federal lands and state regulatory agencies where state regulations mandate permits for in-stream disturbances. Open-cut crossings of fish-bearing streams would also require permits from state agencies. In Montana, the Montana Department of Environmental Quality would review and approve stream crossing methods and at some stream crossing locations could require alternative techniques to minimize impacts to streams and aquatic organisms.

Consolidated Response ENV-6: Concerns Regarding the Influence of Climate Change on the Potential Impacts of the Proposed Project

Many commenters were concerned that impacts of the proposed Project on a variety of resources were not evaluated in light of predicted global climate changes.

As discussed in Section 3.14.3 of the EIS, changes in the U.S. climate over the past 30 years 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 construction-related 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 construction-related stresses on ecosystems through warmer springs, longer growing seasons and related increased productivity (CCSP 2008).

Anticipated impacts resulting from climate change in North America applicable to the regions crossed by the proposed Project include the following:

- 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 an 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 adaptation should include changes to 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. Keystone's construction mitigation that applies directly to the reduction of anticipated climate change-related induced impacts described above include the following:

- Construction mitigation and restoration of riparian habitats at stream crossings (Section 3.3 and 3.7 of the EIS);
- Prevention of the spread and establishment of noxious and invasive weeds (Section 3.5 of the EIS);
- Prevention of the spread of aquatic invasive species (Section 3.7 of the EIS); and
- Limiting hydrostatic test 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 (Section 3.3 and 3.7 of the EIS).

In addition, Keystone would avoid, minimize, and mitigate impacts to wetlands, including depressional wetlands (Section 3.4 of the EIS) which could decrease in abundance due to increased evaporation with increased temperature.

Consolidated Response ERO-1:
Concerns Regarding Sand Hills Erosion

Many comments were received expressing concern that the soil present in the Sand Hills area is susceptible to erosion during construction, operation, and maintenance activities. Commenters were concerned that erosion may not be mitigated and that revegetation would be very difficult in these erosive conditions.

DOS acknowledges that the Sand Hills region contains soils that are especially sensitive to wind erosion. DOS has confirmed that Keystone collaborated with the 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 state road department and has incorporated their recommendations on routing, construction techniques, and restoration techniques to minimize potential damage to Sand Hills vegetation. Section 3.2.2.1 describes specific construction, reclamation, and post-construction activities that would be employed in the Sand Hills based on those recommendations. These activities are also described in Section 4.15 of Keystone's Construction, Mitigation, and Reclamation (CMR) Plan (presented in Appendix B of the EIS), in the proposed Project brochure Pipeline Construction in Sand Hills Native Rangelands prepared for the DOS, and in the site-specific reclamation plan that itemizes construction, erosion control, and revegetation procedures in the Sand Hills region (Sand Hills Construction/Reclamation Unit). The latter two documents are presented in Appendix H of the EIS.

DOS has reviewed the documentation provided by Keystone as part of the Presidential Permit application and review process. DOS also contacted an expert in Sand Hills reclamation who provided input to the Keystone plans included in Appendix H of the EIS as part of its due diligence follow-up, and further facilitated discussions with key agency personnel relative to the use of erosion control mats and blankets and American burying beetle (ABB) habitat restoration. As a result, DOS understands that while Keystone has selected its proposed route in the Sand Hills area to reduce erosion problems to the extent practicable, as documented in Keystone's CMR plan, some minor route re-alignments may occur during construction to avoid particularly erosion-prone locations such as ridge tops and existing blow-out areas and certain selected additional mitigation measures may be applicable (see Section 3.2.2). Should areas of erosion develop after construction and installation of the pipeline, Keystone would be required to restore soil and vegetation to stable conditions. If necessary, fencing would be incorporated to keep livestock from grazing on vegetation within the ROW to hasten vegetation re-establishment.

In the Sand Hills region, reclamation and revegetation on the ROW would be monitored for several years. Keystone has committed to repair erosion and reseed poorly vegetated areas as necessary. Additionally, consistent with procedures for the entire pipeline ROW, landowner reporting would be incorporated as part of monitoring. Landowner reporting would be facilitated through the use of Keystone's toll-free telephone number that would be made available to all landowners on the ROW. Impacts, mitigation and specific construction and restoration methods relative to Sand Hills erosion are discussed in Sections 3.2.1.3, 3.2.2.1 and 3.2.2.2. Keystone has also committed to preventing the spread of noxious weeds in the Sand Hills area. Impacts, mitigation and specific construction and restoration methods applicable to native Sand Hills vegetation are discussed in Sections 3.5.2.1, and 3.5.5.2, and Appendix H.

Consolidated Response ERO-2: Concerns Regarding Erosion Adjacent to Streams and Private Land

Commenters have raised concerns that vegetation removal during pipeline construction activities would cause erosion and siltation into streams and potentially damage private property.

Section 4.5 of the Keystone Construction, Mitigation, and Reclamation (CMR) Plan (presented in Appendix B of the EIS) provides erosion and sediment control measures that would be incorporated into the Project. The CMR Plan provides that temporary sediment barriers would be installed "below disturbed areas where there is a hazard of off-site sedimentation" and "across the entire construction right-of-way at flowing waterbody crossings." As described in Sections 3.2 and 3.3 of the EIS, erosion and sediment control measures would include the use of sediment barriers (silt fencing, hay or straw bales, compacted soil berms, sand bags), trench plugs, temporary slope breakers (water bars), drainage channels or ditches, temporary mulching, and/or the use of tackifier. These measures would minimize, but not eliminate, the risk of sedimentation outside of the construction right-of-way, including streams, water bodies, and private land. Additional erosion control measures may be required as part of the specific permit conditions applied by the USACE or state agencies at individual water crossings.

For construction access, temporary bridges, including subsoil fill over culverts, timber mats supported by flumes, railcar flatbeds, and flexi-float apparatus would be installed across waterbodies. These temporary crossings would be designed and located to minimize damage to stream banks and adjacent lands. The use of temporary crossings would reduce the impacts to the waterbodies by providing access for equipment to specific locations.

Following completion of waterbody crossings, waterbody banks would be restored to preconstruction contours, or at least to a stable slope. Stream banks would be seeded for stabilization, and mulched or covered with erosion control fabric in accordance with the CMR plan and applicable state and federal permit conditions. Additional erosion control measures would be installed as specified in any permit requirements. However, erosion control measures can themselves cause adverse environmental impacts. For example, placement of rock along the bank at a crossing could induce bank failure further downstream. Geomorphic assessment of waterbody crossings could provide significant cost savings and environmental benefits. The implementation of appropriate measures to protect pipeline crossings from channel incision and channel migration can reduce the likelihood of washout-related emergencies, reduce maintenance frequency, limit adverse environmental impacts, and in some cases improve stream conditions.

Consolidated Response FRM-1:
Concerns Regarding Potential Impacts to Ranches and Farmland

Several commenters expressed concern about mitigation of potential impacts to their ranch or farmland and asked for assurance that existing practices, including access, would be minimally disturbed, that the land would be restored to pre-construction conditions or better, and that future decreases in productivity would be mitigated for 3 years or more.

Section 3.9.1.2 of the EIS describes potential impacts to agricultural and range land due to implementation of the proposed Project and includes potential mitigation measures to reduce impacts. During construction, access to rangelands would be allowed to the extent practicable, rangeland fences would be secured to prevent drooping, openings in fences would be closed at the end of each day to prevent escape of livestock, temporary fences with gates would be installed around construction areas to prevent injury to livestock and people, and hard plugs would be left in place and soft plugs would be installed to allow livestock and wildlife movement across trenches. All existing improvements (e.g., fences, gates, cattle guards, irrigation ditches, and reservoirs) would be maintained, and damaged improvements would be restored to pre-construction or better condition.

Section 3.9.1.3 of the EIS and the Construction, Mitigation, and Reclamation (CMR) Plan in Appendix B of the EIS describe procedures to protect soil productivity including topsoil segregation and replacement; soil ripping or chiseling to minimize compaction; soil aeration enhancement using wood chips, manure, or other organic matter; and removal of rocks in excess of 3 inches from the topsoil. Should a decrease in soil productivity nonetheless occur, Keystone would compensate landowners based upon an assessment of the degree to which crop yields were less than those of nearby lands not affected by construction. The value of that compensation would be based upon crop prices at local grain elevators and would occur over at least 3 years. Keystone has committed to compensate for 100 percent of losses for the first year, 75 percent of losses for the second year, and 50 percent of losses for the third year. Keystone has also committed to compensation for losses beyond the third year if the landowner can demonstrate that losses continue to occur and are attributable to the Project.

Consolidated Response FRM-2:
Concerns Regarding Potential Impacts to Irrigated Cropland

Several commenters expressed concern about potential impacts to their irrigation practices due to construction of the proposed Project, and to their crops and livestock if a leak were to occur to surface waters, aquifers, or wells for several years or more during operation.

As indicated in Consolidated Responses FRM-1 and PVT-2 and in Section 4.0 of the Keystone Construction, Mitigation, and Reclamation (CMR) Plan in Appendix B of the EIS, Keystone would work with individual landowners to find the best route through their property to minimize impacts to irrigation systems and surface water resources and wells. Section 3.9.1.3 of the EIS addresses the potential impacts of construction of the proposed Project to irrigation practices. As stated in that section, "If pipeline construction crosses active irrigation ditches, they would not be stopped or obstructed except during the typical 1-day or less time period needed to install the pipeline beneath the ditch." In addition, "Keystone would repair or restore drain tiles, repair fences either using original materials or high quality new materials, and restore farm terraces to their preconstruction functions."

Information on Keystone's liability for spills is presented in Consolidated Response LIA-1. Information on aquifers, including potential impacts from a spill, is presented in Consolidated Responses AQF-1 through AQF-4.

Consolidated Response GEO-1:
Concerns Regarding Landslide Potential

Some commenters on the draft EIS have expressed concern related to landslide potential in steep slope areas, particularly "breakaway" landslides. As discussed in Section 3.1.4 of the EIS, according to the classification of landslide slope movements, the widely accepted terms describing landslides include fall, topple, slide, spread, and flow. These slide classifications can be further modified with the descriptive terms extremely rapid, very rapid, rapid, moderate, slow, very slow, and extremely slow (Turner and Schuster 1996). While the meaning of the term breakaway landslide is not clear, it is assumed that the concern relates to extremely rapid to rapid slides. The potential for these types of landslides is increased in areas that contain steep slopes (>20 percent grade) and may be further influenced by unstable soils or bedrock. Only 4.04 miles of the terrain crossed by the Steele City Segment and 0.70 mile crossed by the Gulf Coast Segment contain steep slopes (>20 percent grade). Most of these steep sections are less than 0.1 mile in length and correspond to stream crossing locations. Mileage along the proposed Project corridor within the High Landslide Hazard Category as defined by PHMSA is provided in Table 3.1.4-1 of the EIS.

The Montana Department of Environmental Quality (MDEQ) is concerned about two areas where Keystone's proposed route would cross landslides, one adjacent to Rock Creek and another on the south valley wall south of the Missouri River crossing. In both cases Keystone has made adjustments in the route to avoid the slide (Rock Creek) or to reduce the distance the pipeline would cross the landslide (south of the Missouri River). Areas in Montana with >15% slopes underlain by Cretaceous shale geology are shown in Table 3.1.4-2 of the EIS.

DOS refers the commenters to Section 4.11 of the Construction, Mitigation, and Reclamation (CMR) Plan (presented in Appendix B of the EIS) submitted by Keystone and revised based on DOS and cooperating agency input, to review erosion and sediment control and reclamation procedures Keystone would employ. These procedures are expected to limit the potential for erosion and encourage slope stability throughout proposed Project operations. Potential slope movements would be monitored during pipeline operation through aerial and ground patrols and through landowner awareness programs designed to encourage reporting from local landowners. Keystone's Integrated Public Awareness (IPA) Plan would enable landowners to report potential threats to the integrity of the pipeline and other emergencies using a toll-free telephone number. For further discussion see Section 3.1.4.2 of the EIS.

Consolidated Response GEO-2:
Concerns Regarding Potential Seismic and Earthquake Fault Hazards

Commenters have expressed concern that potential seismic and earthquake fault hazards pose a risk to the proposed Project particularly in east Texas.

As discussed in Section 3.1.4 of the EIS, seismic hazards include faults, seismicity, and ground motion hazards. Collectively, these three phenomena are associated with seismic hazard risk. Faults are defined as a fracture along which blocks of earth materials on either side of the fault have moved relative to each other. An active fault is one in which movement has demonstrated to have taken place within the last 10,000 years (USGS 2008b). Seismicity refers to the intensity and the geographic and historical distribution of earthquakes. Ground motion hazards are defined as movement of the earth's surface as a result of earthquakes (USGS 2008a). Figure 3.1.4-1 presents the earthquake hazard rank map which shows earthquake hazard risk along the proposed Project route. The map indicates that there is low seismic hazard risk along the entire proposed route.

In east Texas, surface faults have been mapped in the proposed Project area. There is little evidence of ground movement along these faults and as such, they pose very minimal risk to the pipeline (Crone and Wheeler 2000). Epicenter maps show only sparse, low magnitude seismicity (USGS 2008a). Commenters on the draft EIS expressed concern over the potential for seismic or earthquake fault hazards to the proposed Project resulting from the Mount Enterprise Fault Zone. The proposed ROW does cross a portion of the Mount Enterprise Fault Zone. This fault zone is located within the East Texas Salt Basin that is characterized by Mesozoic and Cenozoic sedimentary rocks overlying Jurassic aged Louann Salt deposits. Within the zone, listric normal faults typically dip northward at about 75 degrees from horizontal at the surface and extend into the Louann Salt formation. Fault displacements within this geologic environment are generally thought to be associated with salt deforming plastically at depth and are therefore not likely to be tectonic in origin, and the magnitudes of earthquakes that may be associated with the fault zone would be minor.

A search of the USGS earthquake database found two earthquake events in the vicinity of the Mount Enterprise Fault Zone from 1973 to present. These two events occurred 18 and 35 miles from the proposed Project fault zone crossing and had magnitudes of 3.2 and 3.0 respectively. Earthquakes exhibiting Richter magnitudes less than 4 are considered minor earthquakes and would not threaten the integrity of a buried pipeline. Additionally, the proposed Project corridor does not cross any mapped geologic fault within the Enterprise Fault Zone with documented surface offset.

In addition, approximately 300 surface faults were mapped using Lidar (light distancing and ranging) technology in the Houston area. Movement along these surface faults is not characterized by ground shaking typically associated with earthquakes, but rather, is associated with slow movements of up to 1 inch per year (Khan and Engelkeimer 2008), and these faults are likely associated with salt domes present in this region, where subsidence has been noted to occur. Some of these surface fault movements may also be associated with subsidence due to groundwater and petroleum withdrawal (Kahn and Engelkeimer 2008). The proposed pipeline ROW does not cross any of these Lidar mapped surface faults. For additional information, see Section 3.1 of the EIS.

The pipeline would be constructed to be able to withstand probable seismic events within the seismic risk zones crossed by the proposed Project. The pipeline would be constructed in accordance with USDOT regulations 49 CFR Part 195, Transportation of Hazardous Liquids by Pipeline, and all other applicable federal and state regulations. 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. As described in Response SAF-1, the Pipeline and Hazardous Materials Safety Administration (PHMSA) has regulatory requirements that Keystone must comply with to construct, operate, maintain, inspect, and monitor the proposed Project in a manner that protects the health and safety of the public and the environment. In addition, PHMSA developed 57 Project-specific Special Conditions that Keystone has agreed to implement. DOS, in consultation with PHMSA, has determined that 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.

In accordance with federal regulations (49 CFR 195), Keystone would conduct an internal inspection of the pipeline if an earthquake, landslide, or soil liquefaction event were suspected of causing abnormal pipeline movement or rupture. If damage to the pipeline was evident, the pipeline would be inspected and repaired as necessary. For additional information on pipeline safety, see Response SAF-1.

Consolidated Response GEO-3:
Concerns Regarding Potential Geologic Hazards

Commenters have asked if the pipeline would be constructed to withstand the impacts of flooding, landslides, and other geologic hazards.

Potential impacts of and mitigation for geologic hazards are summarized in Section 3.1.4.2 of the EIS and in Consolidated Responses GEO-1 and GEO-2. Relative to flood hazard, surface waterbodies that would be crossed by the proposed Project are presented in Section 3.3.1.2 of the EIS. Designated floodplain areas that would be crossed by the proposed Project are discussed in Section 3.3.1.3 of the EIS and shown in Table 3.3.1.3-1. As stated in Section 3.3.2.2 of the EIS, the implementation of appropriate measures to protect pipeline crossings from channel incision and channel migration would reduce the likelihood of washout-related emergencies, reduce maintenance frequency, limit adverse environmental impacts, and in some cases improve stream conditions. Therefore, waterbody crossings would be assessed by qualified personnel in the design phase of the proposed Project with respect to the potential for channel aggradation/degradation and lateral channel migration. The level of assessment for each crossing could vary based on the professional judgment of the qualified design personnel. The pipeline would be installed as necessary to address any hazards identified by the assessment. The pipeline would be installed at the design crossing depth for at least 15 feet beyond the design lateral migration zone, as determined by qualified personnel. The design of the crossings also would include the specification of appropriate stabilization and restoration measures. Permits required under Sections 401 and 404 of the CWA would include additional site specific conditions as determined by USACE and appropriate state regulatory authorities. See also Consolidated Response SAF-1.

Consolidated Response GHG-1:
Concerns Regarding Greenhouse Gas Lifecycle Analyses

Many commenters have expressed concerns relative to green house gas (GHG) emissions associated with the production of crude oil originating in the Alberta oil sands, GHG emissions associated with refining oil sands crude oil, and GHG emissions associated with the ultimate use of refined oil products manufactured from oil sands crude oil.

As a result of concerns related to the proposed Project as expressed in comments on the draft EIS, the Department of Energy Office of Policy and International Affairs commissioned an independent analysis (EnSys 2010) of various aspects of the proposed Project, including the well-to-tank and well-to-wheels generation of GHG associated with oil sands crude oil that would be transported on the proposed Project.

In addition, and also resulting from comments received on the draft EIS, the Department of State third-party contractor requested that ICF International LLC (ICF) conduct a detailed review of key existing studies regarding life cycle GHG emissions of petroleum products, including those derived from Canadian oil sands, along with a comparison of life cycle GHG emissions reported in the literature for Canadian oil-sands crude oil and refined products using reference crude oils. Information from these studies as well as information from other credible studies and reports addressing lifecycle GHG emissions have been added to the discussion of cumulative impacts associated with GHG in Section 3.14.3.14 of the EIS. The discussion in the EIS includes summary estimates of GHG emissions resulting from the extraction (both surface mining and in situ methods) and refining of WCSB crude oil, and the combustion of refined products from that crude oil. The updated text also includes comparative GHG lifecycle values for oil sands crude oils, average U.S. crude oil, and the average crude oil currently refined within PADD III.

As shown in Figure 3.14.3-1 of the EIS, 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 Venezuelan1 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 of the EIS). This difference is primarily attributable to the energy requirements of producing steam as part of the in situ extraction process.

Gasoline produced from dilbit generally has lower estimated GHG life-cycle emissions than gasoline produced from SCO 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 of the EIS). 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 of the EIS) is much larger than the percent increases for WTW GHG emission estimates (Figure 3.14.3-1 of the EIS). 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 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-

[1] NETL uses Venezuelan Conventional as a reference crude rather than Venezuelan Bachaquero.

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). For additional information, see Section 3.14.3 of the EIS.

Consolidated Response GHG-2: Concerns Regarding a Potential Causal Connection of Implementation of the Proposed Project and Expanded Oil Sands Production in Alberta and Increases in Refining in the Gulf Coast

Many commenters have expressed the concern that the construction and operation of the Project would accelerate and expand production of crude oil from the Alberta oil sands and would also accelerate and expand the refining of crude oil in PADD III.

As a result of concerns relative to the proposed Project expressed in comments on the draft EIS, the Department of Energy Office of Policy and International Affairs commissioned an independent analysis (EnSys 2010) of various aspects of the proposed Project, including the relationship between the construction and operation of the proposed Project and accelerated or expanded development of the Alberta oil sands and of refining activities in PADD III. In addition, and also resulting from comments received on the draft EIS, the Department of State third-party contractor requested that ICF International LLC (ICF) conduct a detailed review of key existing studies regarding life cycle GHG emissions of petroleum products, including those derived from Canadian oil sands, along with a comparison of life cycle GHG emissions reported in the literature for Canadian oil-sands crude oil and refined products using reference crude oils. These independent analyses indicated that the degree and the rate of development of the Alberta oil sands is not sensitive to the proposed action assessed in the EIS and would occur whether or not the proposed Project is approved and implemented. This finding is consistent with the discussion presented under the No Action Alternative in Section 4.1 of the EIS.

The EnSys (2010) study indicated that the volume of refining that occurs in PADD III would be independent of the proposed Project and is controlled by market demands for refined petroleum products produced in PADD III. The EnSys (2010) study further indicated that the proposed Project would not increase total crude oil deliveries to the U.S. in general or PADD III in particular, but would largely replace decreasing heavy crude oil deliveries to PADD III from other existing sources. 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.

In summary, extensive analysis by EnSys (2011) of crude-oil market dynamics and several modes of bulk transportation indicate that a "No Expansion" scenario where all modes of bulk transport for crude oil out of the WCSB to PADD III remain at 2010 levels through 2030 is highly implausible. As stated in Section

4.1.1 of the EIS, "[u]nder 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." In other words, the delivery of Canadian crude oil to the Gulf Coast region is not dependent on the presence or absence of the proposed Project.

Consolidated Response GHG-3: Concerns Regarding Change in the Rate of Greenhouse Gas Emissions from Oil Sands Production and the Influence of Implementation of the Proposed Project on Commitments to Alternative and Renewable Energy

Some commenters have noted that the Alberta oil sands are a valuable resource and that average GHG emissions associated with the development of the oil sands are decreasing. Other commenters are concerned that reliance on oil sands crude oil may delay U.S. conversion to alternative and renewable energy resources.

The Alberta oil sands represent the second largest recoverable reserves of extractable crude oil in the world. Only the reserves underlying Saudi Arabia surpass the size of Alberta's oil sands reserves. As described in Response CAN-1, technological advancements in extracting crude oil from the oil sands and improved regulatory oversight have resulted in reductions in the "per barrel" lifecycle emissions related to WCSB oil. According to CAPP (2010), there has been a 30 percent decrease in GHG emissions per barrel since 1990. Even with decreases in per-barrel GHG emissions from oil sands crude, overall GHG emissions from oil sands development would continue to rise as exploitation of the resource increases. To address this, in part, Canada has implemented mandatory GHG reporting requirements, legislation requiring measureable reductions in GHG emissions, and a price on carbon emissions from large industrial facilities, including oil sands extraction facilities.

Relative to the potential substitution of alternative and renewable energy for crude oil that would be transported by the proposed Project, 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. As discussed further in Section 4.1.3 of the EIS and Consolidated Response ALT-2, 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), including U.S. conversion to alternative and renewable energy resources. 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. The EPA (2010) analysis reported that implementation of the very aggressive scenario 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 Department of Energy Office of Policy and International Affairs commissioned EnSys (2010) to perform an independent study of various alternatives in transportation infrastructure for crude oil in North America, focused on transport alternatives for crude oil from the WCSB. The results of this study projected that even under EPA's low product demand outlook, a scenario that incorporates the effects of increased use of alternative energy and implementation of aggressive energy efficiency programs, although total crude consumption in the U.S. would decrease, Canadian crude oil imports would increase from 1.9 million bpd in 2009 to 3.6 million bpd by 2030 and WCSB oil sands imports would comprise 90 percent of these Canadian imports. In other words, 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. Thus, it is also true that the proposed Project would have little impact on the commitment to alternative and renewable energy resources since the proposed Project responds to crude oils demands that are independent of that commitment as reflected by the low demand outlook.

Consolidated Response GHG-4: Concerns Regarding the Loss of Boreal Forest and Peat Bogs

Many commenters were concerned about potential impacts of the proposed Project on boreal forests and peat bogs that serve as carbon sequestration sinks.

Boreal forests are not crossed by the proposed Project within either the United States or Canada; therefore the proposed Project would have no direct effects on boreal forest habitats. DOS assumes that these comments refer to the potential loss of boreal forest habitats through oil sand extraction in Canada. As discussed in Consolidated Response CAN-1, the proposed Project is not expected to substantially influence the rate or extent of oil sands extraction (EnSys 2010), and therefore the proposed Project would not substantially influence the effects on boreal forest or peat bog habitats associated with oil sand extraction activities. Nonetheless, given agency and public concerns as addressed in comments received on the draft EIS and the supplemental draft EIS, and for decision-maker information, DOS decided as a matter of policy to expand its discussion of oil sands environmental analyses conducted by the province of Alberta in Section 3.14.4 of the EIS. Issues related to the effects of development of oil sands production in Canada are also addressed in Consolidated Response CAN-1.

Consolidated Response GHG-5: Concerns Regarding EPA Reporting Requirements for GHG Emissions and CEQ Guidance on Greenhouse Gas Assessments

Many commenters have expressed concern relative to the approach taken in the EIS concerning greenhouse gas (GHG) emissions, and other expressed concern about the use of the Council on Environmental Quality guidance on analysis of GHG emissions.

EPA Reporting Requirements

On October 30, 2009, the EPA promulgated the first comprehensive national system for reporting emissions of carbon dioxide (CO2) 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 CO2, methane (CH4), nitrous oxide (N2O), hydrofluorocarbons (HFC), perfluorocarbons (PFC), sulfur hexafluoride (SF6), and other fluorinated gases, including nitrogen trifluoride (NF3) and hydrofluorinated ethers (HFE). Because CO2 is the reference gas for climate change, measures of non-CO2 GHG are converted into CO2-equivalent values (CO2-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.

CEQ Guidance on analyses of GHG Emissions

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, the 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.

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. For discussion of the potential cumulative effects of GHG emissions associated with crude oil production, refining, and consumption of refined products, see Section 3.14 of the EIS.

Consolidated Response GHG-6:
Concerns Regarding Consideration of Low Carbon Fuel Standards in the Greenhouse Gas Assessment

Many commenters question whether the analysis presented in the EIS considered the imposition of low carbon fuel standards throughout the U.S. in the assessment of environmental impacts.

As discussed in Section 3.14 of the EIS, 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 life-cycle GHG emissions 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) 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. The term "emissions leakage" refers to the phenomenon where consumers and producers can purchase or produce fuels at lowest cost by shifting consumption and production to unregulated markets (Yeh and Sperling 2010). In contrast to the Barr's (2010) finding that emissions leakage through fuel shuffling would result in increased GHG emissions, Yeh and Sperling (2010) note that "studies examining the effectiveness of a regional carbon policy or an LCFS suggest that in the case of extreme leakage, the marginal benefits of a carbon policy can be close to zero", but nonetheless they did not project a net increase in GHG emissions.

Adoption of LCFS policies in U.S. and international markets would help mitigate the effect of crude shuffling and emissions leakage. An additional factor that will minimize crude shuffling is the oil refinery sectors' varied processing arrangements designed to process a specific composition of crude oil feedstocks (EPA 1995). The refineries' process optimization for different crude oil feedstocks hinders the ability of fuel refineries to switch crude oil feedstocks from light to heavy blends without incurring additional costs for process modifications.

An additional objective of LCFS policies is to stimulate innovation in the transportation and fuels sectors that would minimize fuel shuffling. For example, a study by the University of California indicates that LCFS "requires innovation in fuel and/or vehicle technologies. Because innovation in the transportation sector is necessary to achieve long-term climate stabilization in any case, the fact that the LCFS will stimulate innovation in the near term is an advantage, not a problem" (Farrell and Sperling 2007). Even in cases where fuel shuffling causes an increase in the GHG emissions resulting from crude oil transport, it is unlikely that overall life-cycle GHG emissions would increase significantly because crude and fuel transportation emissions have a small to moderate effect on well-to-wheel GHG emissions.

Finally, a goal of LCFS is to promote the development of ultra-low carbon fuels such as advanced biofuels, transportation electricity, biomethane, and hydrogen, and thus to provide an incentive to shift the transportation sector away from fossil fuels. Sperling and Yeh (2009) argue that as LCFS creates a need for the transportation sector to greatly reduce their GHG emissions, these new fuels and vehicles have the opportunity to become more economical and increase their market share. See Section 3.14 of the EIS for additional information on LCFS and GHG analyses. See also Consolidated Responses GHG-1 through GHG-5.

Consolidated Response GLF-1: Comparison of an Oil Spill from the Proposed Project to the Deepwater Horizon Incident in the Gulf of Mexico

Many commenters have compared the potential risks of the proposed Project to the explosion of the Deepwater Horizon Project and the resultant release of crude oil into the Gulf of Mexico.

The Deepwater Horizon incident was disastrous and had a major effect on the resources and economies of the Gulf region. The Deepwater Horizon incident involved a crude oil exploration well (Macondo Well) drilled from an offshore drilling platform (Deepwater Horizon platform) operating in deep water within the Gulf of Mexico. The proposed Keystone XL Project is a terrestrial pipeline system that is not analogous in any way to the Macondo/Deepwater Horizon Project.

The Deepwater Horizon drilling platform was completing a well 5,000 feet below the surface waters of the Gulf of Mexico, dozens of miles from the nearest shoreline. The failure of the blowout preventer led to an uncontrolled release of crude oil driven by the formation pressure of a geologic unit thousands of feet below the seafloor. The oil release could not be stopped until the blowout preventer could be capped and ultimately replaced by remotely operated vehicles operating under extreme hydrostatic pressure 5,000 feet below the water surface. In addition, the oil was released directly into the blue water ocean environment of the Gulf of Mexico.

Section 3.13 of the EIS addresses the design of the proposed Project, the probability of a spill from the proposed Project, the potential impacts of a variety of types and sizes of releases, the response procedures that would be implemented to stop the release of oil and to clean up oil released to the environment, and the potential environmental impacts. However, unlike the Deepwater Horizon incident, if there is a spill from the proposed Project, mainline valves can be shut to limit the amount of oil released to the environment. Further, unlike the Deepwater Horizon incident, for most spills from the proposed Project, the emergency responders would have relatively rapid access to the release area, would likely be able to contain at least a portion of the released oil, and would be able to quickly begin containment and cleanup operations after the spill is detected.

Consolidated Response INT-1
Concerns Regarding the Notice of Intent

Many commenters expressed concern that the Notice of Intent (NOI) to prepare an environmental impact statement was deficient and suggested that it was not clear whether or not other federal agencies would conduct subsequent NEPA evaluations of the proposed Project.

The NOI was prepared to be consistent with Council on Environmental Quality (CEQ) regulations, in particular, 40 CFR 1508.22. The NOI included a description of the proposed Project and noted that the scoping process would focus in part on addressing potential alternatives. The scoping process of any EIS is the appropriate mechanism to define and clarify the scope of the action being examined, including the extent of potential involvement of relevant federal and state agencies.

Sections 1.5 and 1.10 of the EIS provide information on the responsibilities of the cooperating federal agencies. Federal permitting requirements are presented in Table 1.10-1 of the EIS. The EIS will be used by federal permitting agencies to comply with their NEPA requirements. DOS is not aware of any federal agency that intends to conduct an additional NEPA review specifically for the proposed Project. As noted in the EIS, Keystone withdrew its request for a Special Permit and PHMSA will not be required to make a decision regarding that permit application. However, the connected actions described in Section 2.5 of the EIS may undergo additional NEPA review by federal agencies.

Consolidated Response JUS-1:
Concerns Regarding Environmental Justice (Potential for Disproportional Impacts to Minority and Low-Income Populations)

Many commenters expressed concern relating to the potential for disproportionate impacts to minority and low-income populations along the proposed Project corridor.

Although DOS considers the analyses presented in Section 3.10.1 of the draft EIS to be consistent with the Council on Environmental Quality (CEQ) guidance for analysis of potential environmental justice effects, Section 3.10.1 of the EIS was revised and expanded to include an assessment of potential pockets of minority and low-income populations down to the census block group level and within 2 miles of the proposed Project centerline and proposed pump stations. The draft EIS described the occurrence of these populations at the county level. In addition, at the request of EPA, the final EIS considers a 'meaningfully greater' criterion of 120 percent compared to state-wide reference populations. The assessment of potential impacts of construction and normal operation of the proposed Project in the census block group analysis indicated that the impacts would not disproportionately affect minority and low-income populations along the pipeline route (see Section 3.10 of the EIS).

Many commenters also suggested that the proposed Project would increase refinery emission levels in PADD III and that the increased emissions would exacerbate health concerns within minority and low-income populations near these refineries. As described in Responses P&N-1, P&N-3, and OIL-4, construction and operation of the proposed Project would be independent of the level of oil refining in PADD III and would not directly result in increased or significantly changed refinery emissions in Gulf Coast refineries.

An additional health concern related to environmental justice expressed by some commenters is the potential for disproportionate health risks to minority and low-income populations along the proposed Project corridor due to a major oil spill. While the susceptibility of these populations to health effects associated with oil spills may be higher than other populations along the pipeline corridor due to their socioeconomic setting, the risks of an oil spill anywhere along the pipeline corridor would be low, particularly given that DOS in consultation with PHMSA has determine that the 57 Project-specific Special Conditions developed by PHMSA and agreed to by Keystone 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. Nonetheless, at the request of EPA, Section 3.10 of the EIS has been expanded to include information on potential impacts 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 in Table 3.10.1-18 and Figures 3.10.1-7 through 3.10-1-13 of the EIS. Additionally, to assess emergency planning and response capabilities along the proposed Project corridor with particular reference to minority and/or low income populations, Section 3.13.5 of the EIS has been expanded to include the results of a telephone survey of Local Emergency Planning Committees (LEPCs) (see Table 3.13.5-7 of the EIS).

Consolidated Response LIA-1:
Concerns Regarding Keystone's Liability for a Spill

Many commenters requested information regarding what Keystone's liability would be in the event of a crude oil spill from the proposed Project.

Section 3.13.5 of the EIS addresses Keystone's liability on the event of an oil spill. As stated therein, Section 1001(32)(B) of the Oil Pollution Act of 1990 (OPA 90) provides 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 U.S. 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 U.S. would fall within the purview of OPA 90.

Therefore, if there is a spill 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 Clean Water Act, 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 Clean Water Act. Keystone would also be subject to penalty provisions of the Rivers and Harbors Act and the Pipeline Safety Act.

In addition to the provisions described above, in the event that a release of crude oil contaminates groundwater, Keystone has agreed that it would be responsible for clean-up and restoration, and for providing an appropriate alternative water supply for groundwater that was used as a source of potable water, or for irrigation or industrial purposes.

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.

In its Environmental Specifications for the Proposed Keystone XL Project (presented in Attachment 1 to Appendix I of the EIS), the Montana Department of Environmental Quality has included the following requirement as a condition of certification of the proposed Project under the Montana Major Faility Siting Act:

> "Keystone shall pay commercially reasonable costs and indemnify and hold the landowner harmless for any loss, damage, claim or action resulting from Keystone's use of the easement, including any resulting from any release of regulated substances or from abandonment of the facility, except to the extent such loss, damage claim or action results from the gross negligence or willful misconduct of the landowner or its agents."

Specific liability warrants and indemnifications are also included within individual easement agreements. As stated in Consolidated Response EAS-1, 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.

Consolidated Response LIA-2: Concerns Regarding Bonding and Decommissioning

Several commenters have suggested that Keystone be required to post a bond to ensure financial responsibility for construction and normal operation, and for any oil spill or spills from the proposed Project.

As stated in Section 1.0 of the EIS, the DOS receives and considers applications for Presidential Permits for certain border crossings and associated facilities. Consistent with NEPA, DOS analyzes the environmental effects of oil pipelines that would cross an international border with the United States prior to making a decision relative to the proposed border crossings. However, DOS does not have regulatory authority over oil pipelines and does not have the authority to require that Keystone provide a letter of credit or a bond to pay for damage to property during construction, cleanup of a crude oil spill, decommissioning the proposed Project, or other potential costs that Keystone may incur related to the proposed Project. However, as a part of its review of Keystone's Presidential Permit Application, DOS reviewed Keystone's financial stability and found it satisfactory to meet its Project-related commitments.

In addition, some states crossed by the proposed route have bonding requirements with which Keystone would have to comply if the proposed Project receives all necessary permits and approvals and is constructed and operated. The State of Montana has reclamation bonding requirements that are applicable to the portion of the pipeline that would be constructed in Montana, but these requirements to not apply to spills (see Attachment 1 to Appendix I of the EIS).

The Bureau of Land Management (BLM) also has bonding requirements. Those requirements would be applicable to the portions of the pipeline that would be constructed on federal lands under BLM management. For information on Keystone's liability in the event of an oil spill, see Section 3.13.5 of the EIS and Consolidated Response LIA-1.

Consolidated Response NOI-1:
Concerns Regarding the Potential Impacts of Noise from Pump Stations

Many commenters have expressed concern about increased noise levels associated with operation of the proposed Project pump stations.

Noise impacts associated with the construction and operation of the proposed Project are addressed in Section 3.12 of the EIS. As stated therein, pump stations would be located as far away from residences as possible while meeting the hydraulic needs of the pipeline system. Keystone would perform a noise assessment survey for each pump station during proposed Project operation and would be required to implement noise abatement measures if necessary to reduce pump station noise as determined from these surveys to levels consistent with relevant state permit requirements and/or local ordinances.

Consolidated Response NOX-1:
Concerns Regarding the Potential Spreading of Noxious Weeds

Several commenters were concerned that the proposed methods for cleaning construction equipment would not prevent the spread of weeds and invasive species. Other commenters were concerned that soil heating resulting from pipeline operations may encourage the spread of weeds and invasive species.

As discussed in Section 3.5.5 of the EIS, Keystone is refining weed survey, control, and monitoring plans in consultation with state and county weed boards. These plans are designed to prevent and if necessary contain the spread of noxious weeds. Keystone would comply with equipment cleaning methods and other noxious weed control recommendations provided by federal, state, and local resource agencies as well as those described in Keystone's Construction, Mitigation, and Restoration Plan (Appendix B of the EIS). These recommendations reflect best management practices as defined by the relevant resource agencies.

Relative to temperature effects, as noted in Section 3.5.5 of the EIS, alteration in vegetation productivity and phenology could occur due to increased soil temperatures associated with heat input from the pipeline. In addition, increased soil temperatures may lead to localized soil drying and localized decreases in soil moisture available for evapotranspiration. However, implementation of the mitigation measures described in Section 3.5.5.4 of the EIS would reduce the potential for any spread of weeds or invasive species associated with the construction and operation of the proposed Project.

Consolidated Response OIL-1:
Concerns Regarding the Likelihood of Spills

Commenters have expressed concern that the risk analysis presented in the EIS states that there would not be any spills from the proposed Project, and others have requested information on potential release sizes.

Section 3.13 of the EIS includes a summary of the risk analyses conducted for the proposed Project, including projections of the estimated frequency of spills from the proposed Project. That section of the EIS does not make the statement that there is no chance that a spill would occur. It does state that small releases (i.e., spills up to 2,100 gallons) are highly likely to occur during construction and operation of the proposed Project. It also states that large releases (i.e., greater than 21,000 gallons) are unlikely to occur, but there is a finite chance that they could occur sometime during the lifetime of the proposed Project. As discussed in Section 3.13.4 of the EIS, DOS analyzed databases of historical spills on existing pipeline systems to establish annual spill frequencies per mile of existing pipeline in the U.S. and then applied that frequency to the length of the proposed Project. The DOS estimates of spill frequency based on the PHMSA database for significant spills range from 1.18 incidents per year for hazardous liquid spills to 1.83 incidents per year for crude oil spills greater than 50 bbl (see Table 3.13.4-1 of the EIS). Using the NRC database, DOS estimates of hazardous liquid spill frequencies range from 1.16 incidents per year for spills of any size to 0.6 incidents per year for spills up to 50 bbl. In addition, for crude oil spills, the NRC database estimates range from 1.38 incidents per year to 0.68 incidents per year for spills up to 50 bbl (see Table 3.13.4-2 of the EIS). The estimate of incident frequencies for hazardous liquid and crude oil spills of any size using both the PHMSA significant spill database for spills greater than 50 bbl and the NRC database for spills up to 50 bbl ranged from 1.78 hazardous liquid spills per year to 2.51 crude oil spills of any size per year.

To assess a spill frequency for the proposed Project specific to the likelihood of a breach of the pipeline itself that would take into account specific design elements, materials strength, anti-corrosion measures, proposed construction and inspection procedures, and applicable regulatory requirements, Keystone performed a two step spill frequency assessment. Keystone initially calculated a baseline spill frequency using the PHMSA (2008) database of 1.38 spills per year. In addition, Keystone then adjusted that spill frequency based on the impact of these proposed Project-specific measures on the key threats to pipeline integrity as described in Section 3.13.4 of the EIS. The adjusted Project-specific spill frequency determined by Keystone for the entire pipeline is 0.22 spills per year (see Table 3.13.4-4 of the EIS).

As noted in the EIS, a spill of petrochemicals or hazardous materials could result from construction and from operation of the proposed Project. As a general rule, small spills (from 1 to 2,100 gallons) are very likely (probability of about 1.0) during both construction and operation. Small spills during construction would typically result from overfilling tanks, broken containers, and similar actions. The vast majority of these spills would occur on construction pads, roads, and other maintained rights-of- way, would likely be detected and reported quickly, and contained and cleaned up with little impact to natural resources or human uses of these resources. Large to very large releases would be very unlikely to occur during construction (maximum tanker truck capacity approximately 6,000 gallons). Larger spills would be possible if a fuel storage tank fails; however, the tanks would be installed inside berms designed to contain greater than 100 percent of the total tank capacity.

As discussed in Sections 3.13.2 and 3.13.3 of the EIS, the probability of a pipeline failure that results in a large (greater than 21,000 gallons) release is low. Large spills would be possible from a major pipeline break, but as stated in the EIS the likelihood would be very small by whatever measure one uses (e.g., incidents per year or barrels per pipeline mile).

Nonetheless, recent large pipeline oil spills (e.g., the Enbridge Pipeline Kalamazoo River spill and the ExxonMobil Silvertip spill) provide evidence that larger spills with significant environmental consequences can occur. However, these recent spills have occurred on older pipeline systems that were constructed under design standards and conditions less comprehensive than the standards and conditions that would apply to the construction, operation, and maintenance of the proposed Project (see Consolidated Response SAF-1). For a discussion of maximum spill volumes in the event of a complete pipeline breach, see Section 3.13.4 of the EIS and Consolidated Response OIL-2.

Consolidated Response OIL-2: Calculation of the Maximum Spill Size

Many commenters have expressed concern that very large to catastrophic oil spills could result from the construction and operation of the proposed Keystone XL pipeline.

As discussed in Section 3.13.4 of the EIS, a complete structural failure of a high strength 36-inch outer diameter pipeline with the wall thicknesses of the proposed Project pipeline would be a highly unlikely event. To cause such a failure, the proposed Project 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. Additionally, the probability of puncture of the X-70 strength steel pipe of the proposed Project would be very low as its puncture resistance is in excess of 65 tons and approximately 98 percent of all excavators in North America have a maximum digging force of less than 35 tons and no excavator has a digging force greater than 40 tons;
- 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 gallons 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). In a briefing to the U.S. Senate on June 8, 2011, PHMSA presented statistics comparing total failures, internal corrosion related failures, and external corrosion related failures in the U.S. crude oil pipeline transmission system from 2002 to 2010 with similar failures in the Alberta crude oil pipeline transmission system over the same time period (see Table 3.13.5-3). The quantity of oil sands derived crude oil in the Alberta system over this time period was likely much higher on a percentage basis than the quantity of oil sands derived crude oil in the entire U.S. system. Nonetheless, the internal corrosion related failures in the Alberta system over this time period per 1,000 pipeline miles per year were approximately 24 percent lower than in the U.S. system. The combined internal and external corrosion related failures in the Alberta system over this time period per 1,000 pipeline miles per year were approximately 13 percent lower than in the U.S. system. Therefore, there is no evidence that the transportation of oil sands derived crude oil in Alberta has resulted in a higher corrosion related failure rate than occurs in the transportation of the variable-sourced crude oils in the U.S. system.
- As described in Section 2.3.1.2, 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 U of the EIS). 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.

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 by Keystone that assessed maximum leak volume from a complete pipeline structural failure using a spill model that is populated with elevation data points occurring at every point of inflection (PI) in the pipeline or every 100 feet, whatever distance is smaller (in most cases it is the PI). The model evaluated over 100,000 data points detailing the profile of the pipeline. The elevation points were acquired through physical survey of the land (accuracy: 2-3 inches) and supplemented with LiDAR (Light Distancing and Ranging system with a vertical accuracy of approximately 6 inches). The model generated spill volume results at each of these data points. 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 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.

Consolidated Response OIL-3: Concerns Regarding the Detection of Small Leaks

Many commenters have expressed concern about the ability to detect small leaks from the proposed Project pipeline.

Information on the Keystone SCADA system, which would be used to remotely monitor and control the pipeline system, is presented in Sections 2.4 and 3.13.4.5 of the EIS along with descriptions of complementary leak detection methods and systems that would be available within the OCC and in the field. It is possible that a slow and small-volume leak that is below the Supervisory Control and Data Acquisition System (SCADA) detection level could continue for some time before it is detected by or reported to the Keystone Operations Control Center (OCC). Since the SCADA system would not likely detect leaks from the pipeline system that are less than 1.5 to 2 percent of the flow volume, a small leak could relatively quickly lead to a substantial release volume. Therefore it is essential that the pipeline system is designed, constructed, operated, and maintained such that the possibility of any release of oil is minimized. For this reason, as discussed in detail in Consolidated Response SAF-1, DOS working in conjunction with PHMSA have developed 57 Project-specific Special Conditions relating to pipeline design, construction, operation, and maintenance that Keystone has agreed to incorporate into the proposed Project and would apply to the proposed Project if the Presidential Permit is approved.

Leak detection technology that would be used to supplement the SCADA system includes software-based volume balance systems that monitor receipt and delivery volumes; computational pipeline monitoring or software-based leak detection systems that use a model to break the pipeline system into smaller segments and monitor each of these segments on a mass balance basis; computer-based, non-real time, accumulated gain/(loss) volume trending to assist in identifying low rate or seepage releases; and direct observation methods, including aerial patrols, intermittent maintenance patrols, and public and landowner awareness programs that are designed to encourage and facilitate the reporting of suspected leaks and events that may suggest a threat to the integrity of the pipeline.

Keystone is committed to educating landowners and response personnel along the proposed pipeline corridor such that they become aware of visual and olfactory indications of undetected oil releases. Many small oil spills are detected through the observation and diligence of people living and working near the pipeline corridor. Visual and olfactory detection of these small leaks typically occurs when the oil surfaces on the ground or is floating on a water body or wet surface. Keystone's 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 U.S. Coast Guard and adopted by PHMSA, EPA, and other regulatory agencies. Leaks may be detected by Keystone personnel in their required monitoring programs or by the public (e.g., farmers, recreationists, public service and public safety personnel, and other citizens).

In comments on the supplemental draft EIS, EPA expressed concern that relying solely on pressure drops and aerial surveys to detect leaks may result in smaller leaks going undetected for some time, resulting in potentially large spill volumes. In light of those concerns, EPA requested consideration of additional measures to reduce the risks of undetected leaks. A PHMSA report (2007) addressed the state of leak detection technology and its applicability to pipeline leak detection. External leak detection technology addressed included liquid sensing cables, fiber optic cables, vapor sensing, and acoustic emissions. In that report PHMSA concludes that while external leak detection systems have proven results for underground storage tank systems there are limitations to their applicability to pipeline systems and they are better suited to shorter pipeline segments. Their performance even in limited application is affected by soil conditions, depth to water table, sensor spacing, and leak rate. While it is acknowledged that some external detection methods are more sensitive to small leaks than the SCADA computational approach, the costs are extremely high and the stability and robustness of the systems are highly variable. Therefore, long-term reliability is not assured and the efficacy of these systems for a 1,384-mile long pipeline is questionable. Relative to additional ground patrols, Keystone responded to a data request from DOS concerning the feasibility of more ground-level inspections. Keystone responded that based on land owner concerns, additional ground-level inspections are not feasible due to potential disruption of normal land use activities (e.g., farming, animal grazing). PHMSA technical staff indicated that such concerns about landowner acceptance of more frequent ground-level inspections were consistent with their experience with managing pipelines in the region. Although widespread use of ground-level inspections may not be warranted, in the start-up year it is not uncommon for pipelines to experience a higher frequency of spills from valves, fittings, and seals. Such incidences are often related to improper installation, or defects in materials. In light of this fact, DOS in consultation with PHMSA and EPA determined that if the proposed Project were permitted, it would be advisable for the applicant to conduct inspections of all intermediate valves, and unmanned pump stations during the first year of operation to facilitate identification of small leaks or potential failures in fittings and seals. In the normal course of maintenance beyond the first year of operation, Keystone would have crews at various places along the proposed Project corridor (e.g., maintenance inspections of cathodic protection system rectifiers, MLVs, and pump stations). These crews would be trained and experienced in the identification of crude oil releases. It should be noted that the 14 leaks from fittings and seals that have occurred to date on the existing Keystone Oil Pipeline were identified from the SCADA leak detection system and landowner reports.

Once a leak or release is detected through any means, Keystone would initiate the response procedures contained within the Pipeline Spill Response Plan (PSRP) and Emergency Response Plan (ERP) so that the release is quickly stopped and impacts to natural resources and the environment are reduced as much as possible. PHMSA data related to pipeline spill detection indicate that the majority of pipeline spills are usually detected within 3 hours, and 97 percent of spills are detected within 7 days (PHMSA 2008). PHSMA data indicate that most leaks that were not detected within the first 24 hours were less than 630 gallons (15 barrels), and the maximum leak volume was about 500,000 gallons (12,000 barrels); the latter was detected after 4 days. For additional information on response plans, see Section 2.4.2.2 of the EIS.

Consolidated Response OIL-4:
Concerns Regarding the Composition of Crude Oil that Would be Transported by the Proposed Project

Commenters have expressed concern about the nature of crude oil transported by the proposed Project, including the use of diluents to reduce the viscosity of oil sands crude oil, particularly in the event of a crude oil release to the environment.

As discussed in Section 3.13.5 of the EIS, crude oil transported by the proposed Project would, for the most part, originate within the Alberta oil sands. The oil produced from the oil sands is typically a very viscous material called bitumen. After impurities such as sand and water are removed, the bitumen is either processed and converted to synthetic crude oil or it is diluted with either lighter crude oils or materials called diluents to reduce its viscosity to acceptable levels for pipeline transportation. The upgrading process and the addition of diluent occur before the oil is delivered to the Keystone pipeline at Hardisty, Alberta.

Upgrading is conducted to ensure compliance with the tariff requirements that would be set for the proposed Project by the U.S. Federal Energy Regulatory Commission (FERC). Among other things, FERC requires that the oil "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."

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). In essence, diluents are either lighter grades of crude oil or lighter hydrocarbons such as kerosene and naphtha. The diluents are integrally combined into the crude oil and would not physically separate if the oil is released from the pipeline. Over time, the volatile aromatic fraction of any crude oil released to the environment would tend to evaporate, and the soluble fraction would tend to enter surface and/or groundwater in contact with the spilled oil plume. Synthetic crude oil and diluent-blended crude oils would behave in a similar manner if released to the environment. The specific gravity of oil sands crude oils that would be transported on the proposed pipeline ranges from about 0.85 to about 0.93, and is less than the specific gravity of water. These crude oils, therefore, float on water and would not initially sink if released to an aqueous environment, either at the surface or in the ground.

Some commenters have expressed concern that dilbits in a pressurized oil pipeline would spontaneously volatilize if the pipeline is breached and further that the diluent would spontaneously separate from the bitumen. As discussed in Section 3.13.5 of the EIS, one measure of the volatility of crude oil and petroleum products is the Reid Vapor Pressure (RVP). RVP is the vapor pressure at equilibrium of a hydrocarbon liquid at 100 degrees Fahrenheit in a closed system. A higher RVP indicates a higher level of crude oil volatility. As indicated in Figure 3.13.5-1, the RVP range for dilbits is comparable to the range for conventional heavy crude oils, and lower than the ranges for medium conventional crude oils, light conventional crude oils, and natural gas condensates. It should be noted that the RVP range for dilbits is lower than the range for condensates, indicating that once a diluent is homogeneously mixed with bitumen to create a dilbit, it exhibits the characteristics of that mixture rather than the characteristics of its individual components. The RVP values confirm that light crude oils and medium crude oils have more “light ends” in that they have a higher concentration of lighter hydrocarbon molecules with lower boiling points that more readily evaporate. Based on information provided at www.crudemonitor.ca, dilbits have light end concentrations in the range of approximately 16 to 25 percent. The light conventional crude oils have light end concentrations in the range of approximately 29 to 42 percent, the medium conventional crude oils have light end concentrations in the range of approximately 27 to 36 percent, and the heavy crude oils have light end concentrations in the range of approximately 13 to 18 percent. These data are consistent with the conclusion that dilbit volatility is comparable to the volatility of conventional crude oils.

Additionally, crude oil is considered a largely homogeneous mixture of a variety of specific hydrocarbon molecules ranging from methane (one carbon) to asphaltines (hundreds of cross-linked carbons). The diluents used in mixture with bitumen to create dilbits are themselves a homogeneous solution of specific hydrocarbon molecules. When blended together with bitumen the resulting crude oil exhibits properties of the mixture – not the individual component parts that were used to produce the blend – and these properties fall within the range of the properties of other crude oils. Blending bitumen with condensate simply puts back components that evaporated from the rock containing the bitumen over millions of years of exposure. However, the gas condensate used as diluent is stabilized (i.e., contains no hydrocarbon gases in solution under high pressure). The assertion that the rapid depressurization of a pipeline as a result of a pipeline breach would result in flash volatilization of gases contained in the diluents is therefore unfounded. The dilbit at rest prior to the development of pumping pressure is stable and at equilibrium between its component parts.

To illustrate this point, the publicly available American Petroleum Institute E&P Tank Program (API 4697) was utilized to assess working and standing losses of volatile compounds resulting from natural crude oil evaporation into air. While this program was designed to model emissions from tanks, it can be employed to provide a rough estimate of working and standing losses from a pipeline crude oil spill. It is recognized that there are limitations in the model’s ability to simulate actual conditions involved in a specific pipeline oil spill at a specific location. For modeling purposes, a dilbit with an API gravity of 18 was compared to gas condensate (a typical diluent, API gravity 55.5), West Texas Intermediate (WTI) crude oil (API gravity 41.0), and Alaska North Slope (ANS) crude oil (API gravity 27.5) using the API model. It should be noted that actual WTI and ANS hazardous air pollutant (HAP) and volatile organic carbon (VOC) concentrations may vary since the actual mix of a specific WTI or ANS crude oil would depend on the composition of the blend. For the dilbit, a full component chromatograph assay of a proprietary unstabilized condensate was available which was modified to match the initial boiling point and heavy ends with bitumen as represented in a published dilbit boiling curve (TIAX 2009). The modeling indicates that the dilbit would produce evaporation (i.e., standing and working) total emissions of VOC and HAP about half the emissions of Alaska North Slope crude oil, and 5 to 20 percent of West Texas Intermediate, respectively. This is because the WTI and ANS crude oils are pipelined straight out of the ground and field stock tank, where the gases under pressure in the deep underground reservoir (i.e. methane, ethane, carbon dioxide) have flashed off but the whole crudes stored at atmospheric pressure are not stabilized by further removing residual light hydrocarbon gases such as propane and butane. In comparison with straight condensate, the bitumen in the dilbit blend acts to reduce the partial pressure of light hydrocarbons in the condensate, slowing evaporation. These results clearly show that the behavior of the dilbit is substantially different than the behavior of the unmixed diluent and bitumen taken separately.

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, as discussed in Section 3.13.5 of the EIS, 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."

Several commenters have raised additional concerns relative to the corrosivity and erosion potential of WCSB crude oils that would be transported in the proposed Project. These commenters are concerned about several potential technical factors, including:

- These crude oils may introduce a type of crude oil that has not been regularly transported in the US pipeline system in the past;
- These crude oils may increase the potential for stress corrosion cracking; and
- These crude oils may increase internal erosion due to the composition and volume of sediments and water (BS&W) in the crude oil stream.

As discussed in Section 3.13.5 of the EIS, heavy and medium-heavy WCSB and other Canadian crude oils have been transported in high volumes in the US onshore pipeline system for many years. For example, based on information available from the Energy Information Administration (EIA), annual volumes of heavy crude oil (API gravity range 18 to 24) from Canada exported to the United States from 1986 to 2010 were as follows:

- 1986 - 181,000 bpd;
- 1990 - 242,000 bpd;
- 1995 - 237,000 bpd;
- 2000 - 433,000 bpd;
- 2005 - 705,000 bpd;
- 2010 - 1,039,000 bpd.

Relative to potential stress corrosion cracking, the composition of the crude oil is not a major factor in determining the potential for stress corrosion cracking (SCC). According to a report prepared for PHMSA (Michael Baker Jr., Inc 2005), "the single most important recommendation in the prevention of SCC is an emphasis on coatings that remain bonded to the pipeline, but allow the passage of cathodic protection current in the event of disbondment. Emphasis should also be placed on the quality assurance/quality control of the surface preparation and field application. These considerations would apply to both new pipeline installations as well as to coating replacement projects. Apart from this consideration, there are limited practical recommendations for pipeline operation processes that can prevent SCC initiation. However, the emphasis must be such that procedures, especially the collection and integration of data specific to SCC development from in-line inspection and direct examinations, are identified and implemented to refine and update this model over time, which will help operators gain a better understanding of the SCC susceptibility. Therefore, it is recommended that operator plans reflect this need for continued data and knowledge development and sharing." These findings and recommendations are consistent with the approaches included within the 57 Project-specific Special Conditions. Further, it is PHMSA's opinion that relative to SCC, key influencing factors include temperature, pipe coating, and external environment (particularly moisture). The proposed coating system for the proposed Project is not conducive to SCC according to PHMSA, and the limits on operating temperature included in Special Condition 15 would further reduce the risk of SCC. Therefore, PHMSA does not consider SCC to be a significant potential risk for the proposed KXL pipeline (PHMSA Pers. Comm. 2011).

Relative to bottom (or basic) sediment and water (BS&W) content in the crude oil stream, a substantive amount of water and inorganic particulate material is entrained in all 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 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.

Relative to the potential erosion concerns during pipeline transmission, DOS has communicated directly with Sam Lordo and Dennis Haynes at NALCO. Both Mr. Lordo and Mr. Haynes noted that in their experience the sediments in diluted bitumen had not created problems of abrasive wear on equipment at refineries. They noted that their work did not relate to transmission pipelines (Lordo and Haynes Pers. Comm. 2011).

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.

The composition of crude oils is also important when considering potential air and water emissions generated during the refining process. 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 very similar in composition (see Section 3.13.4 of the EIS). This finding is consistent with the findings in a 2003 report to the U.S. Environmental Protection Agency prepared by the American Petroleum Institute (API) that included a comparison of Canadian synthetic crude oil with conventional crude oil (API 2003). That report included the following statement:

> "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."

Further, as described in Section 1.4 and in Consolidated Response P&N-1, much of the oil transported by the proposed Project would replace the heavy crude oil traditionally processed due to the continuing decrease in the supply of heavy crude oil from Mexico, Venezuela, and other sources. As a result, the refined products derived from WCSB crude oil would be essentially the same as those that are currently produced from processing heavy crude oil in the Houston area refineries, and the types of emissions would also be the same, as described in Consolidated Response P&N-3.

Consolidated Response OIL-5:
Concerns Regarding the Potential for an Explosion

Many commenters have expressed concern about abnormal pipeline operations that could result in an explosion and consequent oil spill, possible property and environmental impacts, and/or injury or loss of life.

A review of the Pipeline and Hazardous Materials Safety Administration (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 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 3.1.3 of the EIS, 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 have been very few if any explosions associated with crude oil pipelines 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 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. A crude oil spill from the pipeline or at a pump station would result in some hydrocarbon vapors being released to the atmosphere, but the vapors would not be expected to be in confined spaces and therefore would be unlikely to explode.

Further, as discussed in Section 3.13.5 of the EIS and in Consolidated Response OIL-4, diluents will not flash volatilize from the homogenous mixture dilbits in the event of a pipeline breach and subsequent oil release. Additionally, as also discussed Section 3.13.5 the hydrogen sulfide concentration of crude oils that could be transported on the proposed Project is very low and in the very unlikely event of a fire, any small concentration of hydrogen sulfide released would combust with oxygen to produce sulfur dioxide and water.

Consolidated Response P&N-1: Concerns Regarding the Need for the Proposed Project

Many commenters have expressed concern about the need for the proposed Project. Some commenters have suggested that the EIS presents an assessment of need prepared by Keystone and that the assessment of need presented in the EIS is not an independent and unbiased analysis. This response provides information on our analysis and a summary of the key points of the need analysis.

Independent Analysis of Need

Although Keystone provided an assessment of need in its application and related submittals to the Department of State (DOS) for a Presidential Permit, DOS conducted a separate, thorough, and independent assessment as a part of its environmental review under the National Environmental Policy Act (NEPA). The results of the DOS need analysis are presented in Section 1.4 of the EIS.

The analysis of need presented in Section 1.4 of the EIS is based primarily on information presented in reports published by government agencies such as the Energy Information Administration (EIA), the International Energy Agency (IEA), and Canada's Energy Resource Conservation Board (ERCB). The mandates of these three agencies are described below:

- The EIA is a statistical agency of the U.S. Department of Energy (DOE). Its mission is to provide policy-independent data, forecasts, and analyses to promote sound policy making, efficient markets, and public understanding regarding energy and its interaction with the economy and the environment. By law, EIA's products are developed independently and are not subject to clearance by DOE or other government agencies. EIA neither formulates nor advocates any policy positions, and its views may not reflect those of DOE or the Administration. EIA issues a wide range of weekly, monthly, and annual reports on energy production, stocks, demand, imports, exports, and prices. It also prepares analyses and special reports on topics of current interest in response to requests from the Congress, DOE, and other government agencies.
- The IEA is an intergovernmental organization which acts as energy policy advisor to 28 member countries in their effort to ensure reliable, affordable, and clean energy for their citizens. Its current mandate incorporates the "Three E's" of balanced energy policy making: energy security, economic development, and environmental protection. IEA currently focuses its work on climate change policies, market reform, energy technology collaboration, and outreach to the rest of the world, especially major consumers and producers of energy such as China, India, Russia, and the OPEC countries.
- The ERCB is an independent, quasi-judicial agency of the Government of Alberta, Canada. It regulates development of Alberta's energy resources, including oil, natural gas, oil sands, coal, and pipelines. The ERCB's mission is to ensure that the discovery, development, and delivery of Alberta's energy resources take place in a manner that is fair, responsible, and in the public interest. The information and knowledge responsibility of the Board includes the collection, storage, analysis, appraisal, dissemination, and stakeholder awareness of information about energy and utility matters.

In its assessment of proposed Project Purpose and Need, DOS also reviewed information from industry associations, such as the Canadian Association of Petroleum Producers, and private companies such as

Purvin and Gertz and IHS Cambridge Energy Research Associates (IHS CERA). Section 1.11 of the EIS presents a list of the references used in developing the assessment of need.

As a result of public concerns relative to the need for the proposed Project expressed in comments on the draft EIS, the Department of Energy Office of Policy and International Affairs commissioned an independent analysis (EnSys 2010) of various aspects of the proposed Project, including the Project need given long term estimates of demand and existing and projected crude oil transportation infrastructure into the U.S., particularly extending into Petroleum Administration Defense District III (PADD III). This analysis and additional studies published after the April 2010 publication of the draft EIS were used to revise and update the DOS assessment of Project Purpose and Need (see Sections 1.2 and 1.4 of the EIS).

Summary of Need

Many commenters have expressed concerns that the U.S. does not need additional crude oil at this time and that only minor increases would be required in the near future.

Section 1.4 of the EIS presents an overview of the crude oil market, including a revised analysis of the need for the proposed Project. New information available to DOS after publication of the draft and supplemental draft EIS reconfirms that there is a need for additional oil transportation infrastructure to PADD III, evidenced by both current market demand and the long-term projections of crude oil supply and demand. As noted in Section 1.4 of the EIS, the proposed Project would provide access to Western Canadian Sedimentary Basin (WCSB) crude oil in PADD III as existing heavy crude oil sources currently serving PADD III refineries continue to decline. Additionally, construction of the proposed Project would provide needed system redundancy to ensure crude oil deliveries from Canada into the United States if existing transportation pathways were disrupted.

The need for the proposed Project is confirmed in light of international competition for crude oil resources, depleting reserves of heavy crude oil in Mexico, political uncertainties relative to trade with Venezuela, and projections of future crude oil demand in the United States even under EPA's low oil product demand outlook (EnSys 2010).

As described in Section 1.4.2 of the EIS, many of the countries providing crude oil to refineries in PADD III have decreased exports. In particular, a large portion of the crude has previously been supplied by Mexico and Venezuela. However, production from Mexico's mature Cantarell field has been in decline, and from 2006 to 2009 imports of Mexican crude oil have fallen from about 1.6 million bpd to about 1.1 million bpd and are projected to fall further by the projected in service date of the proposed Project. In addition, expansion of the Minatitlan refinery was completed in January 2011 and the expanded refinery processes at least 110,000 bpd of Mexican crude oil, which further reduced the volume exported to the U.S. In addition, Venezuela is diversifying its crude oil customers to decrease its dependence on U.S. markets, and exports from Venezuela to the U.S. have decreased and are expected to continue to decrease. As a result, crude oil from the proposed Project would fill the gap in crude oil supply that currently exists and is expected to increase in the future. As crude oil demand at the PADD III refineries increases, Canadian crude oil could be shipped in the proposed Project to meet that demand.

In its analysis of U.S. crude oil demand, EnSys (2010) considered both the EIA Annual Energy Outlook (AEO) 2010 reference case and the low demand case based upon EPA's February/March 2010 study that examined "more aggressive fuel economy standards and policies to address vehicle miles traveled". Under the AEO reference case scenario, the demand for refinery products sourced from crude oil would increase from 20 million bpd in 2010 to approximately 23.3 million bpd in 2030. Under the low demand case, demand for refinery products sourced from crude oil would decrease from 20 million bpd in 2010 to approximately 16 million bpd in 2030. Given these projections of refined product demand, EnSys projected that the AEO scenario would result in an increase in Canadian crude imports from 1.9 million bpd in 2009 to 3.6 million bpd by 2030. In this case, WCSB oil sands imports would comprise 90 percent of total Canadian imports. Under the low demand case, Canadian crude imports would continue to increase similarly to the AEO scenario. The drop in U.S. oil demand anticipated in the low demand case would be accommodated by a decrease in imports in crude oil from the Middle East and Africa. While existing and other potential oil pipelines from Canada − including the Keystone Mainline and the Alberta Clipper Project − may be sufficient under these scenarios to accommodate near-term total U.S. demand for crude oil, it is projected that by 2020 the projected capacity of the proposed Project would be needed for overall U.S. demand and would be needed sooner to accommodate PADD III demand specifically. See also Consolidated Response ALT-2.

Consolidated Response P&N-2: Concerns Regarding the Export of Crude Oil and Refined Products from the U.S. Gulf Coast

Exports of Refined Products from PADD III

Several commenters have expressed concern that products refined from crude oil transported by the proposed Project would be exported to foreign countries from Gulf Coast refineries. Many of those comments addressed the potential of refined products being exported to China. In addition, some commenters suggested that crude oil that would be transported by the proposed Project would be shipped from the Gulf Coast to China.

As discussed in Section 3.14.3 of the EIS, the refineries in Petroleum Administration for Defense District (PADD) III along the U.S. Gulf Coast provide refined petroleum products to many areas within the U.S. According to the online Independent Statistics and Analysis of the U.S. Department of Energy's Energy Information Administration (EIA), approximately 2.5 billion barrels of refined product was produced in PADD III in 2009. [2] Of this refinery output, approximately 1.5 billion barrels was sent to other PADDs within the U.S.,[3] and approximately 520 million barrels was exported to other countries[4], primarily to Mexico and countries in South America. The total volume of U.S. refined petroleum product exported to China from all 5 PADDs in 2009 was approximately 16 million barrels[5]. Since the EIA database does not provide data on the volume of refined product exported from each PADD to specific countries, it is only possible to compare the total U.S. export volume to China with the total production volume and total export volume for PADD III: the total amount of U.S. refined product exported to China in 2009 (i.e., from all five PADDs) was about 3.1 percent of the total production from PADD III refineries, and about 0.6 percent of the total export of refined product from PADD III. It is unlikely that all of the nearly 16 million barrels exported to China in 2009 was from PADD III, and therefore the percentages noted above are likely higher than the actual percentages for product exported to China from PADD III in 2009.

As noted in Response P&N-1 and Section 1.4 of the EIS, the crude oil transported to PADD III by the proposed Project would largely replace declining supplies of other heavy crude oil, particularly from Mexico and Venezuela. Further, as described in Response OIL-4 and in Section 3.13.5.1 of the EIS, the Canadian crude oil that would be transported by the proposed Project is similar in composition to other heavy crude oils. As a result, it is likely that current refining methods and the movement of refined product in PADD III would continue if the proposed Project is implemented, i.e., the vast majority of refined product would be delivered to customers in the U.S. Although the total volume of refined product exported from the U.S. to China increased from 2008 to 2009, it is unlikely that implementation of the

[2] Available at http://tonto.eia.doe.gov/dnav/pet/pet_pnp_refp2_dc_r30_mbbl_a.htm
[3] Available at http://tonto.eia.doe.gov/dnav/pet/pet_move_ptb_dc_R20-R10_mbbl_m.htm
[4] Available at http://tonto.eia.doe.gov/dnav/pet/pet_move_ptb_dc_R20-R10_mbbl_m.htm
[5] Available at http://tonto.eia.doe.gov/dnav/pet/pet_move_exp_dc_R30-Z00_mbbl_a.htm

proposed Project would result in a substantial increase in the volume of refined product shipped from the U.S. to China or to other countries. It is also clear from the EIA database that refineries in PADD III would not be expected to export all product refined from Canadian crude oil to China as suggested by some commenters. In addition, the refineries in the Gulf Coast are primarily U.S. owned, with no known majority ownership of a refinery by a Chinese company. As a result, there would be no unusual incentive to sell refined product to Chinese customers. In addition, China is substantially increasing its own refinery capacity and is a major competitor for crude oil produced throughout the world. Those conditions suggest that China would be better able to meet its needs for refined product internally and would not require a substantial increase in refined products from PADD III refineries or from other PADDs.

There is also the consideration of the cost of transport of refined product from the Gulf Coast to China. Although some tankers could use the Panama Canal, the use of larger tankers to reduce the number of tanker transits required would require following a different route to China. The alternate routes would require transit around the southern end of South America or the southern end of Africa, both of which are long transport legs that would add to the cost of the product. The transportation costs for shipping refined product from the Gulf Coast to China, even using the Panama Canal for some shipments, would result in a price that would be substantially higher than the price of refined product from other sources. As a result, it is not likely that China would be interested in purchasing refined product from Gulf Coast refiners.

Potential Export of Canadian Crude Oil from the Gulf Coast

The incorrect assertion that implementation of the proposed Project would force crude oil from the proposed Project to be exported from the Gulf Coast is based on a recent paper by Phillip P. Verleger (2011). DOE reviewed this paper and prepared an assessment, that noted: "Verleger's overall view that oil exporting countries will find it necessary to maintain U,S. oil markets is also inconsistent with trends in the world oil market. The International Energy Agency expects that increases in OPEC production will not keep up with increases in oil demand and non-OPEC investment will be needed to meet new demand, especially in nonconventional oil.14 Middle Eastern producers will not have any trouble finding takers for their crude, Even if, as Verleger claims, Saudi Arabia makes price concessions to maintain 700 thousand barreis per day of exports to PADD III, PADD III refiners import between 5-6 million barrels/day of crude oil. PADD III crude imports from its largest suppliers (1.2 million barrels/day from Mexico and 0.9 million barrels/day from Venezuela) are declining. Several PADD III refineries are configured to process oil from Mexico and Venezuela.is With these supplies in decline, there is a significant market opportunity for competitively-priced Canadian dilbit to offset lost heavy oil supplies. There is no reason to believe, as Verleger asserts, that PADD III refiners would not use the Canadian oil shipped in the Keystone XL pipeline (450-630 thousand barrels/day). As mentioned above, TransCanada has already secured contracts for 380 thousand barrels/day, leaving only 70-250 thousand barrels/day of Keystone XL capacity that has not yet found buyers. The Gulf Coast appetite for Canadian oil sands in PADD III will be much higher than can be supplied by just the Keystone XL pipeline. Refinery modeling analysis shows that PADD III imports of Canadian oil sands could rise to 1.8 million barrels per day by 2030 (using a modeling scenario that assumes no additional oil sands pipelines to the British Columbia coast)."

There would be cost considerations in a decision to transport crude oil from Hardisty to the proposed Project delivery points and then to tankers for delivery to foreign ports. There could be storage costs for temporary storage of the oil prior to loading onto the tankers. Due to the size of the tankers, most if not all ship movements to China would not be able to use the Panama Canal until it is expanded. As a result, the routes from the Gulf Coast to China would require transit around the southern end of South America or the southern end of Africa, both of which are long transport legs that would add to the cost of the product. Therefore, shipping Canadian crude oil from Hardisty to the U.S. Gulf Coast and from there to

China would result in transportation costs that would add to the delivered cost of the crude oil. Although there is Chinese ownership in some of the oil sands projects in Canada (see Response P&N-4), it is not likely that the ownership would influence the shipping of crude oil from Hardisty to China via the proposed Project connection to the Gulf Coast due to the cost differential between that source and other sources of crude oil.

As described in Section 1.2 of the EIS, if the proposed Project is approved and implemented, Keystone has contracts to ship approximately 535,000 barrels per day (bpd) of crude oil to the Gulf Coast. It is anticipated that the Canadian crude oil transported to the Gulf Coast would be refined there. Although it is possible that the remaining initial capacity of the system (approximately 165,000 bpd) could be transshipped to China, the cost differential noted above would make that situation highly unlikely.

Consolidated Response P&N-3:
Concerns Regarding Refinery Emissions

DOS received many comments expressing concern about the impacts of emissions that would result from refining crude oil from the Western Canadian Sedimentary Basin (WCSB). The concerns focus on the perception that (1) WCSB crude oil is "dirtier" than other types of heavy crude oil and would therefore emit more pollutants during the refining process than other types of crude oil, and (2) that the emissions would be in excess of those currently released from refineries in the Houston area. These issues are addressed below.

WCSB Crude Oil

Section 3.13.5.1 of the EIS has been revised to compare representative types of crude oil that would be transported by the proposed Project with typical heavy crude oils traditionally processed in the Houston area refineries. Some PADD III refineries are already processing WCSB crude oil transported from Canada by the existing 96,000-bpd EXXON Pegasus Pipeline System. In addition, in 2009 approximately 11,700 bpd of WCSB crude oil was shipped to Gulf Coast refineries from Burnaby, British Columbia by marine tanker. As described in Section 1.4 of the EIS and in Consolidated Response P&N-1, much of the oil transported by the proposed Project would replace heavy crude oils from Mexico, Venezuela, and other sources that are similar to WCSB heavy crude oils. As a result, the types of refinery emissions would likely be similar, as described below. For additional information on the quality of the crude oil that would be transported by the proposed Project, see Response OIL-4.

Refinery Emissions

Emissions, discharges, and wastes from refineries operating in the Houston area must all be in compliance with regulatory requirements, regardless of the source of crude oil. This includes compliance with the Clean Air Act (CAA), the Clean Water Act (CWA), and state and local regulations. The U.S. Environmental Protection Agency (USEPA) and Texas Council on Environmental Quality (TCEQ) will determine whether or not a refinery is in compliance with air quality, water quality, and waste disposal regulations. Refineries may be fined if they are not in compliance with those regulations or they may be required to shut down until compliance is achieved.

Initially, most crude oil transported by the proposed Project would replace heavy crude oil currently obtained from other sources. As a result, it is not likely there would be a substantial increase in the throughput of refineries due to implementation of the proposed Project. Since the crude oil provided by the proposed Project is similar to the existing heavy crude oil stocks of the Houston area refineries, the emissions and discharges from refining would be expected to be very similar to current emissions and discharges. As stated previously, some Houston area refineries are currently processing approximately

108,000 bpd of WCSB crude oil obtained through the EXXON Pegasus Pipeline System and by tanker from British Columbia. The emissions associated with the refining of this heavy crude oil and other light and heavy crude oils in the refinery stream are required to be in compliance with existing refinery environmental permits.

If the demand for petroleum products increases to the point where Houston area refineries desire to increase production, they would likely need new or modified air quality permits. If that occurs, the USEPA or TCEQ would be responsible for reviewing the permit applications and for ensuring that the refinery emissions are in compliance with regulatory requirements, including the use of Best Available Control Technology (BACT), regardless of the source of crude oil.

The final refinery destinations of crude oil that would be delivered by the proposed Project is not known. However, as shown in Table 3.14.3-4 of the EIS, there are 15 refineries which would be directly connected to the hubs to which the proposed Project connects. They are located along an approximately 140-mile-long area along the Gulf Coast. EnSys (2010) reports that "Future level of U.S. refining activity is projected as relatively insensitive to the combination of pipelines available to carry crude out of the Edmonton/Hardisty area." EnSys (2010) also reported that there would be "no significant change in total U.S. refining activity, total crude and product import volumes and costs, in global refinery CO2 and total life-cycle GHG emissions whether KXL is built or not.". As explained in Sections 3.13 and 3.14 of the EIS, the composition of crude oil slates in PADD III, if the proposed Project is implemented, would not be significantly different than the composition of crude oil slates currently refined in PADD III. There is therefore no rationale for assuming that refinery emissions or associated health effects in PADD III would change significantly from the current situation as a result of implementation of the proposed Project. See also Consolidated Response GHG-2.

Consolidated Response P&N-4: Concerns Regarding Chinese Investments

Some commenters have suggested that the government of China or Chinese firms would own all or a portion of the proposed Project.

As described in Section 1.0 of the EIS, TransCanada Keystone Pipeline, L.P. (termed “Keystone” in the EIS) is a U.S. limited partnership, organized under the laws of the State of Delaware; i.e., it is a U.S. firm. Keystone is owned by TransCanada Corporation, a Canadian public company organized under the laws of Canada. There is no Chinese ownership of the proposed Project.

Commenters have also expressed concern that Chinese companies and the Chinese government are investing in oil sands projects in Canada with the intent to ship oil through the proposed Project to the U.S. Gulf Coast, and from there, transport it by marine tankers to China. Those concerns are addressed in Response P&N-2.

Chinese companies have been investing in a wide variety of industries and financial instruments throughout the world, including investments in Canadian oil sands projects. As reported by Reuters (April 12, 2010), Are we providing a references cited section? Also, Staeger can update the reference.

China made its first investment in the oil sands in early 2005, with the state-owned China National Offshore Oil Corporation purchasing a 17 percent share of the startup MEG Energy Corporation, which is developing an oil sands project in northern Alberta. As reported by the International Business Times (November 12, 2010) the China National Petroleum Company (CNPC) at the recent G20 conference in Seoul, South Korea, has made an agreement with Shell to develop Canadian oil sands. CNPC, the parent of PetroChina, signed a memorandum of agreement with Royal Dutch Shell in Beijing on "integrated cooperation" of oil and gas projects in Canada and coal bed methane development in China. Additional Chinese investments in oil sands projects reported by Reuters are listed below.

- In April 2005, Enbridge, Inc. signed an agreement with PetroChina Company Limited (PetroChina), a state-owned oil company, to ship oil on the planned Northern Gateway pipeline, which would take oil sands crude to a deepwater port on British Columbia's Pacific Coast. Enbridge is still planning the line and is expected to file for regulatory approvals. However PetroChina withdrew from the project, citing frustration with the slow approvals process.
- In May 2005, Sinopec Corporation (Sinopec) – a state-owned firm that is China's second-largest oil producer and top refiner – purchased a 40 percent interest in Total SA's undeveloped Northern Lights oil sands project, and in April 2009 it acquired an additional 10 percent stake in the project. The purchase increased Sinopec's stake in Northern Lights to 50 percent. Construction of the project is on hold as the partners weigh new development options.
- In 2009, PetroChina purchased a 60 percent interest in two undeveloped oil sands properties held by Athabasca Oil Sands Corporation, the MacKay and Dover oil sands deposits in Alberta province.
- In April 2010, Sinopec agreed to buy ConocoPhillips' 9 percent stake in Syncrude Canada Ltd, the largest oil sands project in Canada.
- In May 2010, Penn West Energy Trust entered into an agreement with a wholly-owned subsidiary of the China Investment Corporation (CIC) to form a joint venture that will develop Penn West's bitumen assets located in the Peace River area of northern Alberta. CIC will invest a total of $817 million (Canadian; $790 million U.S.) to acquire a 45 percent interest in the partnership.

Reuters (2011) also reported that Sinopec is among a group of investors providing early-stage funding for Enbridge's planned Northern Gateway Pipeline in Western Canada (that project is described in Section 4.1.2.2 of the EIS). The consortium is expected to invest approximately $100 million (Canadian) to fund the regulatory and development costs of the $5.5 billion (Canadian) project. Consortium members would also get guaranteed space on the pipeline and the right to take an equity stake.

In addition, The Calgary Herald (2011) reported that the China National Offshore Oil Corporation (CNOOC) plans to spend $2.1 billion (US) to purchase Opti Canada, Inc. The deal is expected to close in the fourth quarter of 2011 CNOOC would take over Opti's 35 percent interest in four Alberta oil sands projects: Long Lake, Kinosis, Leismer, and Cottonwood, which together have proven reserves of 195 million barrels of bitumen.

Although Chinese firms have invested in oil sands projects in Canada, Keystone currently has long-term contracts to ship 535,000 bpd of Western Canadian Sediment Basin (WCSB) crude oil to delivery points in PADD III (see Response P&N-1 and Section 1.2 of the EIS). Most of the crude oil delivered to PADD III would replace heavy crude oil from Mexico and Venezuela (see also EIS Section 1.4 and Response P&N-1).

Consolidated Response P&N-5:
Requests to Invest in Other Technologies and for Consideration of Energy Policies

Several commenters recommended that Keystone or DOS invest the money intended to finance construction of the proposed Project in alternative energy research and in new alternative energy projects. Commenters have also suggested that instead of considering the proposed Project, DOS should work to create energy policies and goals that incorporate alternative sources of energy, alternative technologies, and conservation of energy.

The proposed Project has the purpose of meeting the market demand for heavy crude oil at refineries in Petroleum Administration for Defense Districts II and III. DOS is conducting an environmental review of the proposed Project in accordance with the National Environmental Policy Act (NEPA) as part of the analysis to determine whether granting a permit for the facilities at the international border are in the national interest in accordance with Executive Order 13337. DOS would not be providing any funding for the proposed Project, does not have the authority to direct federal funds to be invested in particular energy technologies, and does not have the authority to direct the applicant to fund particular energy technologies. DOS has addressed the effect of the implementation of alternative energy sources and technologies, including increasing energy efficiency, on the market demand for crude oil in Sections 1.4 and 4.1.3 of the EIS and in Consolidated Response ALT-2.

DOS concurs that working toward energy policies and goals that incorporate alternative sources of energy, alternative technologies, and conservation of energy is important to the future of the nation. However, DOS does not have the regulatory authority to conduct that work.

Consolidated Response P&N-6: Requests for a Supplemental Draft EIS

Many commenters requested that DOS prepare and circulate a supplemental draft EIS or a revised draft EIS.

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. 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 were 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 a supplemental draft EIS.

The supplemental draft EIS was prepared and circulated in compliance with the Council of Environmental Quality NEPA regulations and DOS guidelines (Using Existing Environmental Analyses). It included copies of new reports and other documents relevant to the proposed Project and revisions to portions of the draft EIS. Additional information on the supplemental draft EIS is presented in Section 1.9.2 of the EIS.

Consolidated Response P&N-7: Concerns Regarding Keystone's Purpose for the Proposed Project

Several commenters have suggested that the purpose of the proposed Project as stated in the draft EIS and in the supplemental draft EIS is "too narrow" and should be expanded to address issues such as meeting national goals for clean energy and other broader goals.

In its regulations for implementing NEPA, the Council on Environmental Quality (CEQ) states that an EIS "shall briefly specify the underlying purpose and need to which the agency is responding in proposing the alternatives including the proposed action" (40 CFR 1502.13, Purpose and Need). The Keystone XL Project has been proposed by a private applicant that has identified a specific purpose for the proposed Project as stated in its application to DOS for a Presidential Permit. That purpose is presented in Section 1.2 of the EIS consistent with CEQ regulations for implementing NEPA.

Consolidated Response P&N-8: Requests to Ship Canadian Crude Oil to Refineries that are Closer to the Source of Crude Oil

Several commenters suggested that the crude oil produced in the oil sands of the Western Canadian Sedimentary Basin (WCSB) should be transported to existing or new refineries that are in Canada or closer to the WCSB than the U.S. Gulf Coast.

As described in Sections 1.2 and 1.4 of the EIS and in Consolidated Response P&N-1, the purpose of the proposed Project would primarily be to meet the market demand for crude oil feedstock at existing refineries in the Gulf Coast region. Shipping WCSB crude oil to refineries in Canada or to refineries in the northern tier of the U.S. would not satisfy the proposed Project purpose and need.

Consolidated Response P&N-9: Requests for Information on the National Interest Determination Process

Many commenters requested information on the DOS National Interest Determination (NID) process for the proposed Project, and requested that the determination process presented in a supplemental draft EIS to allow for public review and comment.

In determining whether or not the proposed Keystone XL Project would be in the national interest, DOS will follow the procedures of Executive Order (EO) 13337. As described in Sections 1.3 and 1.5.1 of the EIS, EO 13337 designates and empowers DOS "to receive applications for Presidential permits for the 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."

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 determination of national interest. 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.

During the public comment periods for the draft and supplemental draft EISs that were conducted consistent with NEPA, DOS received and considered comments regarding issues relevant to the NID as well as comments on the draft and supplemental draft EISs. During September 2011, DOS will also host public meetings in each of the six states through which the proposed pipeline would pass. The meetings will be held in the state capitals of Montana, South Dakota, Nebraska, Kansas, Oklahoma, and Texas, with an additional meeting in the Sand Hills region in Nebraska and along the Gulf Coast near Port Arthur, Texas. This will be followed by a final public meeting in Washington, DC. These meetings will provide an opportunity to voice views on whether granting or denying a Presidential Permit for the pipeline would be in the national interest and to comment on economic, energy security, environmental, and safety issues relevant to that determination.

Pursuant to EO 13337, after the final EIS is issued, the consulting agencies specified in the EO will have 90 days to provide views on whether granting a presidential permit for facilities at the international border for the proposed Project is in the national interest. As noted above, DOS will also solicit public comments on whether granting the permit would be in the national interest. As required by EO 13337, DOS will review all of the available information and documentation, including the final EIS and comments submitted by federal and state agencies and the public.

If the Secretary of State finds that issuance of a permit to Keystone would serve the national interest, the Secretary will prepare a permit with the terms and conditions required to serve the national interest and will notify the Secretaries or the heads of the reviewing agencies agencies of the proposed determination, as required by EO 13337. The proposed NID will include consideration of the information presented in the final EIS, consideration of public comments on the final EIS provided in writing and at the public meetings, and comments received from the government agencies specified in EO 13337.

The Secretary of State will issue the Presidential permit, which will include an NID, unless within 15 days of notifying the agencies, an agency disagrees with the proposed determination. If the latter occurs, the Secretary of State will consult with any such requesting official and, if necessary, will refer the application, together with statements of the views of any official involved, to the President for consideration and a final decision.

Consolidated Response PIP-1: Concerns Regarding the Purchase of Pipe for the Proposed Project

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. Keystone has also stated 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.

As described in Consolidated Response SAF-1, the Pipeline and Hazardous Materials Safety Administration (PHMSA) has regulatory requirements that Keystone must comply with to construct, operate, maintain, inspect, and monitor the proposed Project in a manner that protects the health and safety of the public and the environment. Those regulatory requirements address pipe manufacturing, steel quality, inspections, and other requirements related to pipe quality. In addition, PHMSA developed 57 Project-specific Special Conditions that Keystone has agreed to implement (presented in Appendix U). Many of the Special Conditions specify greater detail than the PHMSA regulatory requirements for pipe, such as the materials to be used, the manufacturing specifications, and inspections that would need to occur in order for pipe to qualify for installation on the proposed Project irrespective of the originating location of the pipe mill.

Keystone has committed that it would review the pipe manufacturer's procedure specifications prior to the pipe mill initiating purchase or production of steel to ensure the material meets all applicable PHMSA requirements including the applicable Special Conditions, the API 5L Line Pipe Specification, and Keystone's internal 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 to 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.

Section 2.3.1 of the EIS has been revised to include this and other information on pipe requirements and inspections.

Consolidated Response PVT-1:
Concerns Regarding the Cumulative Effects of Several Pipelines through an Area

DOS received comments expressing concern about the effects of the proposed Project when combined with the effects associated with existing pipelines in the vicinity of the proposed Project.

Cumulative effects associated with implementation of the proposed Project are discussed in Section 3.14 of the EIS. Those impacts include consideration of existing pipelines, proposed pipelines, and reasonably foreseeable future pipelines. Proposed and reasonably foreseeable future pipelines may be subject to applicable state and federal permitting and environmental review under either NEPA or relevant state regulations as appropriate. In some areas the proposed Project would parallel the easements of existing pipelines. The avoidance of some environmental impacts to undisturbed corridors in these areas may offset the potential for cumulative impacts in the previously disturbed areas.

Consolidated Response PVT-2:
Concerns Regarding the Proximity of the Proposed Project to Existing Structures and Facilities

Several commenters expressed concern about the distance between the proposed pipeline and existing structures and other facilities on private land.

As discussed in Section 3 of the EIS, Keystone would work with individual landowners to find the best route though their property within the constraints of the proposed Project design and the stipulations of environmental permits. Implementation of the procedures presented in the Keystone Construction, Mitigation, and Reclamation (CMR) Plan (Appendix B of the EIS) would also reduce impacts to these areas. The CMR Plan would be amended prior to construction to include additional mitigation measures agreed to by Keystone through the NEPA process.

Consolidated Response PVT-3: Landowner Comments Related to Construction of the Existing Keystone Oil Pipeline

Some commenters have provided comments or concerns regarding the construction activities that occurred on the previously approved and currently operating Keystone Oil Pipeline.

Issues relating to the construction and operation of the existing Keystone Oil Pipeline project are only addressed when directly relevant to the proposed Project (e.g., existing Keystone Oil Pipeline spill history).

Consolidated Response RDS-1: Concerns Regarding Potential Road Damage and Roadway Safety

Many commenters have expressed concern about the potential for damage to roads and roadway structures during construction of the proposed Project and safety along roadways in the vicinity of the proposed route during construction.

As summarized below and further described in revised Section 3.10.3 of the EIS, Keystone has committed to a program that would include inspection of roadways and roadway structures, repair of damage that may occur to those facilities, establishment of an approved Traffic Management Plan, and coordination with state and local transportation agencies.

Condition of Roads and Roadway Structures

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. Keystone's pipeline contractor 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. The pipeline contractor would also inspect cattle guard crossings prior to their use. If they are determined to be inadequate to handle anticipated construction traffic, the cattle crossing may be matted, or Keystone would establish an alternate crossing, enhance existing structures, and, if needed, 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 the work force. Local road officials would be actively engaged in the routine assessment of current road conditions.

Traffic Safety

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 the 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 use permits.

Consolidated Response REG-1: Concerns Regarding Keystone's Request for a Special Permit for the Proposed Project

Many commenters have expressed objections or concerns regarding Keystone's application to the Pipeline and Hazardous Materials Safety Administration (PHMSA) for a Special Permit. The Special Permit 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) specified in 49 CFR 195.106.

On August 5, 2010, Keystone withdrew its application to PHMSA for a Special Permit and would be required to construct the proposed Project in accordance with the PHMSA regulations at 49 CFR Parts 194 and 195. In addition, PHMSA developed 57 Project-specific Special Conditions that Keystone has agreed to implement and to incorporate into its manual for operations, maintenance, and emergencies that is required by 49 CFR 195.402 (see appendix U). DOS, in consultation with PHMSA, has determined that 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.

Consolidated Response REG-2: Concerns Regarding the Department of State as the Lead Federal Agency, Regulating Commerce and Permitting for the Safe Design of the Proposed Project

Commenters expressed concern about DOS being the "lead permitting agency" for the proposed Project, and the DOS role in regulating commerce, permitting, and safe design of the proposed Project.

As described in Section 1.0 of the EIS and in Consolidated Response ENR-1, DOS issues Presidential Permits that allow the construction, operation, maintenance, monitoring, and inspection of petroleum pipelines at the international border pursuant to authority delegated from the President in Executive Order (EO) 11423, as amended by EO 13337, including a determination of national interest. The President's authority to grant such permits derives from the President's constitutional authority to conduct the foreign affairs of the United States. Such a Presidential Permit does not regulate foreign commerce, and therefore, DOS does not issue permits for the import of crude oil, or other petroleum projects, nor does it regulate petroleum pipelines in the U.S., even those pipelines that cross an international border. Further, DOS does not have the authority to issue any permits for the proposed Project other than the Presidential Permit.

It was determined that DOS was the most appropriate agency to serve as lead federal agency for the reviews required by the National Environmental Policy Act (NEPA), which includes preparation of this EIS, in accordance with the Council on Environmental Quality (CEQ) regulations implementing NEPA, in particular 40 CFR 1501.5. DOS recently served in the role of lead federal agency for the environmental reviews of two other crude oil pipeline applications, the Alberta Clipper Project and the Keystone Oil Pipeline Project.

DOS takes seriously its responsibilities to thoroughly evaluate the environmental effects of its Presidential Permit decisions consistent with NEPA and other relevant laws and regulations. In conducting the environmental review of the proposed Project, DOS followed NEPA, CEQ regulations and guidance, and all other applicable laws and regulations. In addition, DOS was assisted by a third-party environmental contractor in the environmental review of the proposed Project. That contractor, Cardno ENTRIX, has conducted environmental impact assessments of nearly 30 proposed pipeline projects and has experience in such work throughout the U.S., including in the states along the proposed corridor. DOS also consulted extensively with other relevant federal agencies that have particular technical expertise and authority relevant to the proposed Project. As a result, DOS considers the EIS to be in full compliance with the requirements of a NEPA environmental review. Other federal agencies, such as the Bureau of Land Management and the U.S. Army Corps of Engineers, will issue their own Records of Decision for any relevant permits they would issue for the proposed Project. If Keystone receives a Presidential Permit from DOS, it must also obtain all applicable federal, state, and local permits and authorizations prior to the initiation of construction of the proposed Project. The key permits and approvals that Keystone must obtain, as well as the associated regulatory requirements, are listed in Table 1.10-1 of the EIS. The responsibilities of the cooperating agencies that assisted DOS is preparing the EIS are described in Section 1.5 of the EIS.

The key mitigation measures that would be required by federal, state, and local environmental permits are presented in the resource sections within Section 3.0 of the EIS. In addition, the procedures that Keystone would implement to avoid or minimize impacts are presented in Keystone's Construction, Mitigation, and Reclamation Plan (Appendix B of the EIS) and in the Montana Department of Environmental Quality's Environmental Specifications for the Keystone XL Project (Attachment 1 to Appendix I of the EIS). The agencies issuing permits would be responsible for ensuring that Keystone is in compliance with the permit stipulations. DOS has no authority to enforce requirements under permits issued by other agencies.

The Pipeline and Hazardous Materials Administration (PHMSA) is responsible for ensuring that the proposed Project is designed, constructed, operated, and maintained in accordance with its regulations presented in 49 CFR, Parts 194 and 195, and in accordance with the 57 Project-specific Special Conditions developed by PHMSA (see Appendix U of the EIS). Keystone has agreed to incorporate these measures into the proposed Project if the Presidential Permit is granted, and will also incorporate them into its Operations and Maintenance Manual for the pipeline. 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. Sections 2.3.1 and 3.13.1.1 of the EIS and Consolidated Response SAF-1 provide information on the PHMSA regulations, the Special Conditions, and the role of PHMSA in ensuring compliance with the regulations.

Consolidated Response REQ-1: Requests for Additional Information, Including Maps of the Proposed Project

Several commenters requested that DOS provide them with maps and other Project-specific information.

Publically available documents, maps, and additional information on the proposed Project are available on the DOS Project website (http://www.keystonepipeline-xl.state.gov/clientsite/keystonexl.nsf). To view detailed maps of the proposed route at that site, click on "Project Documents," then click on "Supplemental Filings" for July 6, 2009 and May 19, 2010. Additional Project-specific information can be found either in the EIS or on the DOS Project website.

Consolidated Response REQ-2: Requests for Locations of Paper Copies of the EIS and that Copies of the Draft EIS, Other Specific Information, or References be Sent Directly to the Commenter

Many commenters requested information on the locations where they could review paper copies of the draft EIS and other commenters requested copies of the draft EIS.

Paper copies and CDs of the draft EIS, the supplemental draft EIS, and the EIS were provided to landowners and stakeholders as requested and were also made available at local libraries along the route (see the distribution list in Appendix V of the EIS for lists of stakeholders and libraries). Electronic versions of the draft EIS, the supplemental draft EIS, and the EIS were posted on the DOS Project website (http://www.keystonepipeline-xl.state.gov/clientsite/keystonexl.nsf). DOS attempts to minimize the number of paper copies that are distributed to be consistent with overall federal environmental sustainability goals. However, all stakeholders who specifically requested paper copies rather than CDs were accommodated.

Consolidated Response REQ-3: Requests to See Comments and Responses to Comments on the Draft EIS

Several commenters requested that DOS send the comments on the draft EIS and the responses to those comments to them directly.

All substantive comments received on the draft EIS and supplemental draft EIS and the responses to those comments are presented in the EIS. The actual comment letters received and the transcripts of public comment meetings are included in the Administrative Record for the proposed Project.

Consolidated Response RES-1: Concerns Regarding Emergency Response Plans

Some commenters requested that a supplemental draft EIS be issued to include a more complete Emergency Response Plan (ERP) and allow for public review of that plan. Other 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.

As discussed in Section 2.4.2.2 of the EIS, 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 resulted from the CWA as amended by the Oil Pollution Act of 1990 (OPA 90) and as implemented by 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 substantial 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 substantial threat of such a discharge." Keystone would submit a Pipeline Spill Response Plan (PSRP) to PHMSA prior to the initiation of proposed Project operations in accordance with the requirements of 49 CFR 194. The PSRP would describe how spills would be responded to in the event of a release from the proposed Project resulting from any cause (e.g., corrosion, third-party damage, natural hazards, materials defects, hydraulic surge). The plan would address the maximum spill scenario and the procedures that would be in place to deal with the maximum spill. The PSRP requires PHMSA review and approval; however, there is a 2-year grace period under which operations can proceed, thus allowing PHMSA time to review the document in light of as built Project conditions and to require incorporation of any needed changes to ensure system safety prior to PHMSA approval.

As required by 49 CFR 195.40, Keystone would also prepare and follow a manual of written procedures for conducting normal operations and maintenance activities and handling abnormal operations and emergencies. This manual would be reviewed by PHMSA at intervals not exceeding 15 months, but at least once each calendar year, and appropriate changes would be made as necessary to ensure that the manual is effective. This manual would be prepared before initial operations of the proposed Project and appropriate sections would be kept at locations where operations and maintenance activities are conducted. The emergency section of this operations and maintenance plan would be prepared by Keystone in a separate document that Keystone refers to as the Emergency Response Plan (ERP).

While EPA has authority under the CWA and OPA 90 with respect to regulation of onshore non-transportation related facilities and EPA requires the development and submittal of a Facility Response Plan (FRP) for any such facility, 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, as previously noted in Section 2.3.

Keystone would therefore be required to develop a PSRP for review and approval by PHMSA and an ERP for review by PHMSA for the proposed Project. PHMSA may request EPA and U.S. Coast Guard consultation on the response elements of the PSRP. Keystone would share on its own volition portions of the PSRP with community emergency responders along the proposed pipeline corridor to ensure an appropriate level of collaborative emergency response planning. However, based on a PHMSA advisory bulletin issued on November 3, 2010, Keystone would be required to share the ERP with local emergency responders in relevant jurisdictions along the proposed Project corridor.

While the draft PSRP and the draft ERP for the proposed Project are not yet available, Keystone prepared similar plans for the existing Keystone Oil Pipeline Project. These plans for the proposed Project would have the same general approach as those plans 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 System ERP is included as Appendix C to the EIS (some of the ERP and the PSRP are considered confidential by PHMSA and the U.S. Department of Homeland Security). As described in Section 3.13.1.1 of the EIS, the existing Keystone Oil Pipeline Project documents would be used as templates for the plans for the proposed Project. Project-specific information would be inserted into the plans as it becomes available. 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. PHMSA would require a certification from Keystone that necessary emergency response equipment is available in the event of an unplanned spill prior to providing Keystone with an authorization to begin operating the proposed Project.

The Emergency Response Plan (ERP) and the Pipeline Spill Response Plan (PSRP) for the proposed Project would consider the accessibility of rural areas in responding to leaks from the pipeline or aboveground facilities and other incidents. In addition, as discussed in Section 3.13, the Local Emergency Planning Committees (LEPCs) have already been contacted concerning the proposed Project and would be included in emergency planning (see Table 3.13.5-7 of the EIS). See also Consolidate Response OIL-4.

Consolidated Response RUR-1: Concerns Regarding Potential Changes to Rural Lifestyles

Several commenters expressed general concerns that the pipeline would be located in rural and agricultural lands, potentially impacting rural character and producing environmental concerns that could not be easily addressed in remote locations. Others commented that the proposed Project would have general benefits for rural areas.

As discussed in Section 3 of the EIS, the presence of construction crews, material, and activities would produce short term effects on rural or relatively undeveloped areas during active construction periods. However, construction activities along the right-of-way would be performed in accordance with the Keystone Construction, Mitigation, and Reclamation Plan (presented in Appendix B of the EIS), applicable permit requirements, and the requirements of individual easements, thus ensuring that the visual impact of the pipeline would be minimal in most areas. However, the visual quality of areas along the proposed Project route that are currently wooded would be altered by the pipeline corridor. The aboveground portions of the proposed Project (mainline valves, pump stations and the associated electrical distribution lines) would also alter the visual character of small portions of rural or undeveloped areas. Except at major river crossings, the valves sites would typically be no more than 20 miles apart in compliance with PHMSA Special Condition 32, and there are 30 pump stations along the route. Thus, the general rural character of most areas along the proposed Project corridor would not experience a substantial visual change, although residents living near any aboveground Project-related facilities would experience a change in visual quality.

The Emergency Response Plan (ERP) and the Pipeline Spill Response Plan (PSRP) for the proposed Project would consider the accessibility of rural areas in responding to leaks from the pipeline or aboveground facilities and other incidents. In addition, as discussed in Section 3.13, the Local Emergency Planning Committees (LEPCs) have already been contacted concerning the proposed Project and would be included in emergency planning (see Table 3.13.5-7 of the EIS). See also Consolidated Response RES-1.

Consolidated Response SAF-1: Concerns Regarding the Design and Safety of the Proposed Project

DOS received many comments expressing 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 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. PHMSA 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. If the proposed Project is approved, PHMSA would maintain continual regulatory oversight over the proposed Project throughout construction, testing, start-up, operation, and maintenance.

As described in Sections 2.3.1, 2.4, and 3.13.1 of the EIS, to protect environmental resources and the public health and safety, Keystone would be required to construct, operate, maintain, inspect, and monitor the proposed Project in compliance with the PHMSA requirements presented in 49 CFR 195, relevant industry standards, and applicable state standards. In addition, PHMSA developed 57 Project-specific Special Conditions that Keystone has agreed to implement and to incorporate into 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. DOS, in consultation with PHMSA, has determined that 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.

The following potential mitigation measures have been suggested by regulatory agencies:

- EPA suggested considering the placement of additional intermediate mainline valves, particularly in areas of shallow groundwater and at river crossings of less than 100 feet where sensitive aquatic resources may exist. Project-specific Special Condition 32 developed in consultation with PHMSA that Keystone agreed to incorporate into the proposed Project plan states:

  > "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."

  The requirement to take into consideration elevation, population, and environmentally sensitive locations to minimize consequences of a release, and the maximum valve spacing of 20 miles exceed what is currently required in 49 CFR § 195.260. Based on Special Condition 32, the proposed Project was redesigned to increase the number of intermediate mainline valves from 76 to 104 and some previously planned valve locations were moved. As per standard code requirements, there would also be two valves at each of the 30 pump stations. Section 2.2.2 has been updated to include information on the additional intermediate valves and valve locations.

  EPA also expressed concern that relying solely on pressure drops and aerial surveys to detect leaks may result in smaller leaks going undetected for some time, resulting in potentially large spill volumes. In light of those concerns, EPA requested consideration of additional measures to reduce the risks of undetected leaks, such as external leak detection systems. A PHMSA report (2007) addressed the state of leak detection technology and its applicability to pipeline leak detection. External leak detection technology assessed in that report included liquid sensing cables, fiber optic cables, vapor sensing, and acoustic emissions. The report concluded that while external leak detection systems have proven results for underground storage tank systems, there are limitations to their applicability to long pipeline systems and they are better suited to shorter pipeline segments. The performance of external leak detection systems even in limited application is affected by soil conditions, depth to water table, sensor spacing, and leak rate. Some external detection methods are more sensitive to small leaks than the SCADA computational approach, but the stability and robustness of the systems are highly variable, particularly over long pipeline segments, and the costs are extremely high. Therefore, long-term reliability is not assured and the efficacy of these systems for a 1,384-mile long pipeline is questionable. It may be possible, however, to incorporate external leak detection methods along discrete segments of pipeline where particularly sensitive resources may exist. For example, in the development of the original Keystone pipeline, specific analysis was commissioned at the request of the North Dakota Public Utilities Commission to examine the possibility of using external leak detection in the area of the Fordville aquifer. That analysis was performed by Accufacts, Inc., a widely recognized expert on pipeline safety that has authored a report for the Pipeline Safety Trust on leak detection technology. The Accufacts, Inc. report (2007) on the Fordville aquifer noted:

> "Such real-time external systems should be considered as complementing CPM [computational pipeline monitoring] leak detection in those few ultra-sensitive areas where the environment can quickly spread low rate releases. These systems may be justified in a few areas that can have high consequences because of the number of sensitive receptors (i.e., people) or the potential to critically impact the environment."

The author of the report defined "ultra-sensitive" areas as those areas where low rate or seepage pipeline release could "reach a sensitive area, have serious consequences, and could not be actively remediated." (Accufacts, Inc. 2007).

DOS in consultation with PHMSA and EPA determined that Keystone should commission an engineering analysis by an independent consultant that would review the proposed Project risk assessment and proposed valve placement. The engineering analysis would, at a minimum, assess the advisability of additional valves and/or the deployment of external leak detection systems in areas of particularly sensitive environmental resources. The scope of the analysis and the selection of the independent consultant would be approved by DOS with concurrence from PHMSA and EPA. After completion and review of the engineering analysis, DOS with concurrence from PHMSA and EPA would determine the need for any additional mitigation measures.

- EPA and other commenters on the draft and supplemental draft EIS recommended consideration of ground-level inspections as an additional method to detect leaks. The PHMSA report (2007) on leak detection presented to Congress noted that there are limitations to visual leak detection, whether the visual inspection is done aerially or at ground-level. A limitation of ground-level visual inspections as a method of leak detection is that pipeline leaks may not come to the surface on the right of way and patrolling at ground level may not provide an adequate view of the surrounding terrain. A leak detection study prepared for the Pipeline Safety Trust noted: "A prudent monitor of a pipeline ROW will look for secondary signs of releases such as vegetation discoloration or oil sheens on nearby land and waterways on and off the ROW" (Accufacts 2007). PHMSA technical staff concurred with this general statement, and noted that aerial inspections can provide a more complete view of the surrounding area that may actually enhance detection capabilities. Also, Keystone responded to a data request from DOS concerning additional ground-level inspections and expressed concerns that frequent ground-level inspection may not be acceptable to landowners because of the potential disruption of normal land use activities (e.g., farming, animal grazing). PHMSA technical staff indicated that such concerns about landowner acceptance of more frequent ground-level inspections were consistent with their experience with managing pipelines in the region. Although widespread use of ground-level inspections may not be warranted, in the start-up year it is not uncommon for pipelines to experience a higher frequency of spills from valves, fittings, and seals. Such incidences are often related to improper installation, or defects in materials. In light of this fact, DOS in consultation with PHMSA and EPA determined that if the proposed Project were permitted, it would be advisable for the applicant to conduct inspections of all intermediate valves, and unmanned pump stations during the first year of operation to facilitate identification of small leaks or potential failures in fittings and seals. It should be noted however, that the 14 leaks from fittings and seals that have occurred to date on the existing Keystone Oil Pipeline were identified from the SCADA leak detection system and landowner reports.

- EPA requested that language be added to address Keystone's commitment to cleanup and restoration, even in groundwater areas that are not linked to navigable waters of the U.S. In response, Keystone has agreed that it would be responsible for providing appropriate alternative water supply, and for clean-up and restoration in the event of a release of crude oil into groundwater, even in areas that are not linked to navigable waters of the U.S.
- EPA requested the following to be included in the PSRP and/or ERP:
  - Develop a contingency plan before commencement of operation for emergency response and remedial efforts to control contamination from a release in order to avoid and minimize potential impacts through all media (i.e., surface and ground water, soil, and air) to minority, low-income and Tribal populations rather than relying solely on after-the-fact compensation measures. Provide translation of emergency information to linguistically isolated communities. Provide bottled water to Environmental Justice communities in the event the drinking water supply becomes contaminated.
  - Provide notification to individuals affected by soil or groundwater contamination, ensuring the public is knowledgeable and aware of emergency procedures and contingency plans (including posting procedures in high traffic visibility areas), and providing addition monitoring of air emissions and conducting medical monitoring and/or treatment responses where necessary.
  - Designate staging and deployment areas for oil spill equipment, and dedicated oil spill-contingency-plan buildings and equipment at each of the pump stations.
  - Develop spill scenarios that cover a variety of terrains, oil products, spill volumes, and seasonal conditions.
  - Have aerial photographs of the pipeline to aid in spill response planning.
- The risks of spills or leaks could be assessed using 3-dimensional modeling of a spill of a particular magnitude in the Sand Hills. The modeling could assess fate and transport, including routes of exposure to human and ecosystem receptors (Professor Gates and Professor Woldt, UNL).

Consolidated Response SOI-1: Concerns Regarding Construction During Wet Weather Conditions

Several commenters raised concerns regarding impacts associated with pipeline construction during wet weather conditions or when soil is saturated.

Section 3.2 of the EIS discusses potential impacts to soil associated with construction during wet weather conditions or in saturated soils. Table 3.2.2-1 of the EIS provides the monthly average total precipitation in the vicinity of the proposed Project, and the potential impacts and mitigation associated with wet weather construction are presented in Section 3.2.2.1 of the EIS.

As described in Section 2.18 of the EIS and in the Construction, Mitigation, and Reclamation (CMR) Plan (presented in Appendix B of the EIS), Keystone would restrict certain construction activities and work in cultivated agricultural areas in excessively wet soil conditions to minimize rutting and soil compaction. Work would be restricted when soil rutting could cause mixing of topsoil and subsoil layers, excessive buildup of mud on tires and/or cleats, excessive ponding of water on the soil surface, and when the potential exists for excessive soil compaction.

Keystone would use low impact construction techniques during extremely wet weather, limiting work to areas that have adequately drained soils or sufficient vegetative cover to prevent mixing of topsoil and subsoil, or requiring the installation of geotextile construction mats when necessary. Orders to halt construction would occur when recommended by the Environmental Inspector for the construction spread affected by wet weather conditions if conditions are such that excessive environmental degradation due to continuing work would be possible.

Consolidated Response SOI-2:
Concerns Regarding Topsoil, Backfill, and Restoration

Commenters have raised concerns about decreased productivity from the mixing of topsoil and subsoil and resulting from subsoil backfilling activities.

Sections 2.3.2.3 and 3.2.2.1 of the EIS describe procedures that would be used during construction to segregate topsoil from subsoil in areas containing prime farmland soils and range and pasture lands. In areas where topsoil segregation would be required, the actual depth of topsoil would be removed up to a maximum depth of 12 inches and segregated from subsoil. A “triple lift” method would be used in areas where deep soils would be excavated, primarily over the pipeline trench in cultivated fields to minimize impacts to agricultural production. This method would involve stockpiling three different soil horizons, including the topsoil horizon, as described in Section 3.2.2.1 of the EIS. This separation of topsoil from subsoil would allow for proper restoration of the soil during the backfilling process. These procedures separating topsoil would reduce the potential for mixing of subsoil and topsoil. Additional information on topsoil segregation methods is also provided in Section 4.3 of the Keystone Construction, Mitigation, and Reclamation (CMR) Plan (presented in Appendix B of the EIS).

Section 2.3.2.8 of the EIS and the Keystone CMR Plan provide additional information on the restoration methods that Keystone would incorporate into the proposed Project.

Consolidated Response TAX-1:
Concerns Regarding Taxes

Many positive comments were submitted regarding the increased property and other tax revenues that would be generated in the counties and states that the pipeline would traverse. Several cited information provided in a report by Perryman (2010). However, some commenters expressed concerns about the potential for Keystone to reduce its tax obligation by negotiating reduced tax rates or exemptions.

An estimate of the county and state property taxes that would be generated by the proposed Project is provided in Section 3.10.2.2 of the EIS, with a summary of estimated property taxes by county for the proposed Project presented in Table 3.10.2-3 of the EIS. The annual property tax expenditures for the proposed Project would total $140.5 million, including about $63 million in Montana, $15.4 million in South Dakota, $21.9 million in Nebraska, $2 million in Kansas, $14.3 million in Oklahoma, and $23 million in Texas. In addition, another $0.875 million would be paid annually for the Houston Lateral. The EIS also indicates that these new property tax revenues could represent a significant increase to existing levies in affected counties, including a 151 percent increase in Montana, 37.2 percent increase in

South Dakota, 14.4 percent increase in Nebraska, 2.7 percent increase in Kansas, 18.9 percent in Oklahoma, and a 9.7 percent increase in Texas.

Perryman (2010) independently reported that significant local and state tax revenues (apparently non-property tax revenues) would be generated by the proposed Project, although the numbers are different from those presented in the EIS. See also Consolidated Response ECO-1 for additional perspective on the Perryman (2010) analysis.

In Kansas, legislation enacted in 2006 (House Substitute for Senate Bill 303) provides for property tax exemptions, income tax credits, and income tax deductions for certain energy related industries. There are five energy related industries that are addressed:

- Crude oil or liquid natural gas pipelines;
- Integrated coal gasification power plants;
- Crude oil refineries;
- Integrated coal or coke gasification nitrogen fertilizer plants; and
- Cellulosic alcohol plants.

In each instance, the property tax exemption is for property that is purchased, constructed, or installed after December 31, 2005. Proposed Project facilities that might be included within the reach of this legislation include the two new pump stations that would be added to the Cushing Extension of the existing Keystone pipeline. At this time DOS is not aware of other state level legislation that would limit or reduce the estimated tax revenues in the EIS.

Consolidated Response TER-1
Concerns Regarding the Potential for Terrorism

Several commenters have expressed concern about the vulnerability of the proposed Project to actions by terrorists.

In the aftermath of the terrorist attacks that occurred on September 11, 2001, terrorism has become a very real issue for infrastructure throughout the country. Since that date, there has been an increase in security awareness throughout the pipeline industry and the nation. The Office of Homeland Security was established with the mission of coordinating the efforts of all executive departments and agencies to detect, prepare for, prevent, and protect against, respond to, and recover from terrorist attacks within the U.S.

There are currently about 500,000 miles of interstate oil and gas transmissions lines, and hundreds of thousands of miles of oil and gas gathering lines and distribution lines throughout the country. Although safety and security are important considerations for those facilities, the number, lengths, and locations of the pipelines precludes having guards, cameras, and other types of continuous surveillance and protection measures. However, to reduce the vulnerability of the proposed Project to terrorism, the pipeline would be buried to a minimum depth of 4 feet, and mainline valves, pump stations, and the Cushing tank farm would be surrounded by locked security fencing. The pipeline route would be routinely inspected by air and ground as required by PHMSA, and the aboveground facilities would routinely be visited by maintenance and monitoring crews.

The likelihood of future attacks of terrorism or sabotage occurring along the proposed Project route, or at any of the many crude oil pipelines, refined product pipelines, natural gas pipelines, or other energy facilities throughout the U.S. is unpredictable given the disparate motives and abilities of terrorist groups. As a result, certain information related to proposed Project design, construction and operation are considered proprietary and confidential, such as the exact locations of High Consequence Areas (HCAs). HCAs for operating pipelines are located within the national pipeline mapping system for public review at a county level. However detailed HCA location information will not be released. Keystone must identify the final HCAs prior to operations and PHMSA will check these.

Consolidated Response VAL-1:
Concerns Regarding Property Values

Concerns were raised about how the proposed Project might affect property values and marketability for the lands that would be crossed by the pipeline. In addition, commenters expressed concern about their ability to continue to use the land for agricultural purposes, or to develop housing subdivisions in some areas.

Section 3.10.2.2 of the EIS has been revised to include additional information on potential changes in property values, including information on the results of studies of the effect of several types of facilities on property values. The results of the these studies indicate that residential and agricultural properties located on or adjacent to pipeline easements could have property values worth more or less than comparable nearby properties that were not encumbered by pipeline easements. However, those differences generally were statistically insignificant and the absolute dollars involved were not significant relative to the overall property value and sales prices. Thus, it does not appear that the proposed Project would have a major impact on residential and agricultural property values. For a review of potential impacts to land values associated with oil spills and releases, see Section 3.13.5.8.

Relative to potential modification to existing land uses, agricultural uses would not likely be affected since the top of the pipeline would be buried to a depth of at least 4 feet as required by the Pipeline and Hazardous Materials Safety Administration (PHMSA) regulatory requirements and the relevant Special Conditions developed by PHMSA and agreed to by Keystone. As stated in Special Condition 19:

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

Except where aboveground facilities would be constructed, incorporation of these measures will allow agricultural activities to resume after construction. Keystone would establish a 50-foot-wide permanent right-of-way (ROW) for the pipeline. This permanent ROW would not be available for siting structures such as housing developments. However, housing developments and other structures would be allowed up to the edge of the permanent ROW.

Consolidated Response WAT-1:
Concerns Regarding Potential Water Quality Impacts

Commenters have raised concern regarding the potential impacts to streams, rivers, and other waterbodies due to the open-cut stream crossing method. Commenters have also suggested that construction activities should be conducted at times when reduced impacts to aquatic and riparian species and their habitat would occur.

As described in Section 2.3.3.5 of the EIS, most waterbody crossings along the proposed Project route would involve one of the open-cut methods listed below:

- Non-flowing open-cut crossing method (for waterbodies that do not have a perceptible flow at the time of construction);
- Flowing open-cut crossing method;
- Dry-flume open-cut method; or
- Dry dam-and-pump method.

The non-flowing open-cut method would be used for all waterbodies with no visible flow at the time of construction. Prior to construction, timber matting and riprap would be installed in the entire area to minimize compaction from equipment. The pipe section would be fabricated adjacent to the stream or in a staging area. The contractor would trench through the stream, lower in the pipe then backfill. After installation, the contractor would remove the timber mats, restore the grade to pre-construction condition and replace the topsoil (unless saturated conditions exist). Permanent erosion control would be required.

If there is flow at the time of construction, the flowing open-cut crossing method may be used. In this method, the trench is dug through flowing water. Backhoes operating from one or both banks would excavate the trench within the streambed. In wider rivers, in-stream operation of equipment may be necessary. The contractor would trench through the stream, lower in a pipe that is weighted for negative buoyancy, then backfill. It is important during flowing open-cut crossings to minimize the time of construction to reduce impacts to waterbody channel and banks. For minor waterbodies (less than 10 feet wide at the water’s edge), the trenching and backfill of the crossing would typically require no more than 24 hours and for intermediate waterbodies (10 to 100 feet wide) would typically require no more than 48 hours. Major waterbodies (more than 100 feet wide) would be crossed as quickly as possible. It is possible that the time required to accomplish the crossings of major waterbodies could exceed 48 hours. To the extent practicable, non-flowing open-cut crossings would be the preferred crossing method.

Keystone would use the dry-flume method on selected environmentally sensitive waterbodies where technically feasible. The dry-flume method is used for sensitive, relatively narrow waterbodies free of large rocks and bedrock at the trenchline and with a relatively straight channel across the construction ROW. Use of this method involves installing dams upstream and downstream of the construction area and installing one or more pipes (flumes) that would extend along the course of the waterbody and through both dams. Streamflow would be carried through the construction area by the flume pipe(s). Keystone would install flumes with sufficient capacity to transport the maximum flows that could be generated seasonally within the waterbody. The upstream and downstream ends of the flumes would be incorporated into dams made of sandbags and plastic sheeting (or equivalent material). The flumes would remain in place during pipeline installation, backfilling, and streambank restoration.

Prior to trenching, the area between the dams typically would be dewatered. Backhoes working from one or both banks, or from within the isolated waterbody bed, would excavate the trench across the waterbody and under the flume pipes. After the trench is excavated to the proper depth, a prefabricated section of pipe would be positioned and lowered into the trench. The trench then would be backfilled with the excavated material from the stream unless otherwise specified in stream crossing permits, and the dams and flues would be removed.

As an alternative to the dry-flume crossing method, Keystone could use the dry dam-and-pump method on selected environmentally sensitive waterbodies where practical. The dry dam-and-pump method is similar to the dry-flume method except that pumps and hoses would be used instead of flumes to move water around the construction work area. When using this method, Keystone would initiate pumping while the dams are being installed to prevent interruption of streamflows. Where necessary to prevent scouring of the waterbody bed or adjacent banks, the downstream discharge would be directed into an energy-dissipation device or concrete weight. As with the dry-flume method, trenching, pipe installation, and backfilling would be done while water flow is maintained for all but a short reach of the waterbody at the actual crossing location. Once backfilling is completed, the stream banks would be restored and stabilized and the pump hoses would be removed.

However, the horizontal directional drilling (HDD) method would be used at major rivers to avoid impacts to water quality and fisheries. This method involves drilling a pilot hole under the waterbody and banks, then enlarging the hole through successive ream borings with progressively larger bits until the hole is large enough to accommodate a pre-welded segment of pipe. Throughout the process of drilling and enlarging the hole, a water-bentonite slurry would be circulated to lubricate the drilling tools, remove drill cuttings, and provide stability to the drilled holes. Keystone has created Site Specific Waterbody Crossing Plans (Appendix D) that describe the procedures to be used at each perennial waterbody crossed using the HDD method. After installation, Keystone would conduct cathodic protection and in-line inspection surveys to determine if any damage may have resulted to the pipe coating during the construction process. Response WAT-4 addresses concerns regarding the potential for the release of drilling fluids during horizontal directional drilling.

As stated in Section 3.3.2.2 of the EIS, prior to commencing any stream crossing construction activities, Keystone would be required to obtain a permit under Section 404 of the Clean Water Act (CWA) and, in some cases, under Section 10 of the Rivers and Harbors Act of 1899 administered by the USACE and a CWA Section 401 water quality certification as per state regulations. The USACE and some state agencies would require measures to limit unnecessary impacts to aquatic and riparian species and their habitat during construction as a condition of the crossing permits. In Montana each crossing of a perennial stream would be reviewed in the field by personnel from the Montana Department of Environmental Quality and specific requirements for stream crossings would be determined upon completion of that review. Keystone would prefer to construct stream crossings during low flow periods, or for intermittent streams, when there is no flow. However, the timing of stream crossing will be determined by the limitations imposed in environmental permits, weather conditions, and other variables.

For additional information on open-cut water crossings methods see Section 2.3.3.5 of the EIS and Section 7 of the Keystone Construction, Mitigation, and Reclamation Plan (Appendix B of the EIS). The potential impacts of the various methods of waterbody crossings are addressed in Section 3.3.2.2 of the EIS.

Consolidated Response WAT-2:
Concerns Regarding a Compensatory Mitigation Plan for Jurisdictional Wetlands and Potential Impacts to Non-Jurisdictional Wetlands

Many commenters expressed concerns relative to the amount and type of compensatory mitigation Keystone would be required to provide for impacts to wetlands and also expressed concerns relative to impacts to non-jurisdictional wetlands.

As discussed in Sections 3.4.4 and 3.4.5 of the EIS, procedures outlined in the proposed Project CMR plan (see Appendix B to the EIS) for wetland crossings would be implemented to minimize potential construction- and operations-related effects and wetlands affected by construction activities would be restored to the extent practicable. Implementation of measures in the CMR plan (see Appendix B to the EIS) would avoid or minimize most impacts on wetlands associated with construction and operation activities, and would ensure that potential effects would be primarily minor and short term. Involvement of the USACE and FWS, as well as other federal and state agencies, during the early phases of project routing and siting identified high quality wetlands or areas requiring additional protection to be avoided. Data reviewed to avoid and minimize impacts to wetlands to the extent possible included: National Wetland Inventory maps, aerial imagery, soil surveys, and field wetland surveys. Wetland impacts were further avoided or minimized by horizontal directional drilling to avoid impacts, locating the route next to existing utilities to minimize impacts, perpendicular crossing of riparian wetland features to minimize impacts where possible, and route variation to reduce the total length of the wetland crossing to minimize impacts.

Various state and federal agencies have expressed concerns about and provided recommendations for compensatory mitigation of jurisdictional wetland losses. Pipeline construction through wetlands must comply with USACE Section 404 permit conditions. The requirements for compensatory mitigation would depend on final USACE decisions on jurisdictional delineations. All wetland crossings regardless of whether the wetland qualifies as jurisdictional or non-jurisdictional under the USACE's Section 404 permits would receive construction mitigations as described in the CMR Plan (see Appendix B of the EIS) and any other applicable guidance from the USACE. Most wetlands would be restored after pipeline construction. Compensatory mitigation, where required by USACE, would be provided for all permanent impacts to wetlands. Recommendations for compensatory mitigation provided to DOS by state and federal agencies that have input to compensatory mitigation determinations include:

- Where appropriate and applicable, a plan to compensate for permanent wetland losses should be developed to include:
  - Permanent impacts to forested wetlands in Texas should be calculated to include the total width of area where trees would be removed during long-term maintenance including any removal areas beyond the 30-foot wide maintained area. All forested wetland clearing is considered a permanent impact that would require compensatory mitigation (Texas Parks and Wildlife, TPW).
  - In Texas, the wetland mitigation plan should be developed in consultation with TPW, and that impacts to all wetland types are addressed in the wetland mitigation plan and mitigate for these impacts (TPW).

DOS received comments on the draft EIS from EPA concerning completion and submittal of a compensatory mitigation plan approved by the USACE. EPA recommended that each EPA region and USACE district be consulted with to determine appropriate compensation and to develop a wetland mitigation plan for inclusion in the EIS. EPA and USACE have discussed the approach to determining appropriate wetlands compensation and the final level of required compensation and mitigation would ultimately be determined by:

- USACE regulatory offices with input from EPA, USFWS Ecological Services field offices, and state fish and wildlife agencies; or
- States in their 401 certifications or certificates of compliance.

Impacts to forested wetlands are long-term and would be considered permanent. Portions of water oak/willow oak forest communities may or may not be determined to be wetlands (as defined by USACE and EPA) and may or may not be eligible for compensatory mitigation through the Section 404 CWA process. It is not possible to entirely avoid impacts to bottomland hardwood wetlands in Texas. However, aerial mapping of field delineated wetlands were reviewed by Keystone working with USACE personnel in the Fort Worth and Galveston district offices to determine the best crossing locations to minimize impacts to wetlands, including bottomland hardwood wetlands. Methods used to avoid and/or minimize permanent impacts to bottomland hardwood wetlands include the use of horizontal directional drilling, the routing of the proposed Project next to previously impacted areas along existing linear utilities, the perpendicular crossings of riparian wetland features wherever possible, and the selection of route variations to reduce the total length of the wetland crossings.

Each USACE district would be consulted to determine the kind of compensation that would be required for the permanent conversion of forested wetland to herbaceous wetland and to determine compensation that would be required for each District Nationwide or individual permit issuance. Nationwide Permit pre-construction notification packages or individual permit applications would include the mitigation plans agreed upon with the USACE. Preliminary mitigation discussions with the USACE districts have identified the following mitigation options for the project:

- USACE Omaha District (Montana, South Dakota, and Nebraska)
  - Compensatory mitigation for permanent wetland impacts would follow Permittee Responsible Mitigation at ratios established by field offices in Montana and Nebraska because no wetland mitigation banking opportunities occur in the vicinity of the proposed Project.
- USACE Tulsa District (Oklahoma)
  - Compensatory mitigation for permanent wetland impacts to forested wetlands would include preservation of existing forested wetlands because no wetland mitigation banking opportunities occur in the vicinity of the proposed Project.
- USACE Fort Worth and Galveston Districts (Texas)
  - Compensatory mitigation for permanent wetland impacts would be based on the results of functional wetland assessments completed for all anticipated impacts to forested wetlands which would be used to determine an appropriate number of wetland credits to be purchased from USACE-approved wetland mitigation banks in proximity to the proposed Project.

Mitigation plans would identify district and wetland-type specific monitoring requirements that could include re-vegetation monitoring conditions similar to those typical for Nationwide permits, such as:

- Wetland re-vegetation would be monitored after construction for a period of 3 years or until wetland re-vegetation is successful (defined as the point when cover of herbaceous and/or woody plant species is similar to the vegetation in adjacent wetland areas that were not disturbed by construction).
- Annual visual comparisons of the wetland would be made for plant species, relative vegetation cover and presence of exotic plant species not found in adjacent areas.
- Unsuccessful re-vegetation at the end of 3 years would be addressed through development of a remedial re-vegetation plan developed in consultation with a professional wetland ecologist to actively re-vegetate the wetland, and re-vegetation efforts would continue until the wetland is successfully re-vegetated.

DOS received a letter from EPA questioning whether all wetlands along the proposed Project corridor would be covered by a Nationwide Permit. DOS understands that USACE will determine eligibility for each wetland crossing under the Nationwide Permit program and also understands that EPA will review that eligibility determination. EPA also recommended that USACE review the proposed wetland impacts as a single project requiring an individual CWA Section 404 permit.

Consolidated Response WAT-3:
Concerns Regarding Potential Impacts to Wetlands and Waterbodies due to Construction of Ancillary Facilities

Some commenters expressed concern that the impacts of ancillary Project facilities were not fully addressed in the draft EIS.

Section 3 of the EIS has been revised to address the potential impacts to surface water, groundwater, and wetlands from construction and normal operation of pump stations, pipe storage yards, valve stations, temporary and permanent access roads, and other associated facilities based on the informational available at the time the EIS was written.

Consolidated Response WAT-4:
Concerns Regarding the Potential for the Release of Drilling Fluids During Horizontal Directional Drilling

Commenters expressed concern regarding the toxicity and potential impacts of drilling fluids that would be used with the horizontal directional drilling (HDD) method.

Section 3.3.2.2 of the EIS addresses water quality issues and Section 3.7.3.1 addresses the potential impacts to fisheries resources associated with an unintentional release of drilling fluids during HDD operations.

As reported in Section 7.4.5 of Keystone's Construction, Mitigation, and Reclamation Plan (see Appendix B to the EIS):

> "drilling fluids and additives utilized during implementation of a directional drill shall be non-toxic to the aquatic environment. The Contractor shall develop a contingency plan to address a frac-out during a directional drill. The plan shall include instructions for monitoring during the directional drill and mitigation in the event that there is a release of

> drilling fluids. Additionally, the waterbody shall be monitored downstream by the Contractor for any signs of drilling fluid. The Contractor shall dispose of all drill cuttings and drilling mud as permitted by the appropriate regulatory authority at a Keystone-approved location. Disposal options may include spreading over the construction right-of-way in an upland location approved by Keystone or hauling to an approved licensed landfill or other site approved by Keystone."

Site specific plans for each HDD crossing would be developed to ensure safe completion of the operation, and to plan for containment of any accidental release of drilling fluids and would require review and approval by USACE and relevant state regulatory agencies.

Consolidated Response WIL-1: Concerns Regarding the Approach to Wildlife Analyses

Several commenters indicated concerns relative to the approach to assessing potential impacts to wildlife described in the EIS.

DOS conducted the wildlife impact analysis in Section 3.6 of the EIS consistent with NEPA and with Council on Environmental Quality guidance. The Threatened and Endangered Species and Species of Conservation Concern impact analyses are addressed in Section 3.8 of the EIS. The final Biological Assessment (BA) under the ESA relative to the American burying beetle (ABB) is presented in Appendix T of the EIS.

Wildlife habitat resources potentially affected by the proposed Project and the potential impacts of construction and normal operation of the proposed Project to those resources are addressed in Sections 3.5, 3.6 and 3.8 of the EIS. DOS gathered concerns related to wildlife resources during the scoping process for the proposed Project. Information on the issues of concern and other relevant information regarding wildlife was obtained through consultation with federal and state resource management agencies and through reviews of available literature. The EIS presents potential Project-related impacts on wildlife habitat and wildlife resources including habitat loss, habitat alteration, habitat fragmentation, mortality and productivity effects from collision, displacement from preferred habitats, and predation. These direct and indirect impacts are identified and discussed in compliance with NEPA in Sections 3.5, 3.6, and 3.8 of the EIS, and cumulative impacts to these resources are addressed in Section 3.14. As a result, DOS considers the assessments of potential impacts of construction and normal operation of the proposed Project to wildlife to be consistent with the requirements of a NEPA environmental review. Section 3.13.6.4 of the EIS addresses potential impacts to wildlife due to a spill from construction or operation of the proposed Project. See also Consolidated Response WIL-2.

Consolidated Response WIL-2: Concerns Regarding Species Covered by the Migratory Bird Treaty Act and the Endangered Species Act

Several commenters were concerned about potential Project impacts to migratory birds, bald eagles, golden eagles, and endangered species from construction and operation of the Project and associated electrical power distribution lines.

Potential impacts to these wildlife resources are disclosed and discussed in Sections 3.6 and 3.8 of the EIS. Evaluation of the electric power distribution lines for ESA protected species is included in the Biological Assessment (BA), Appendix T of the EIS. Electric power providers are engaged in consultation under the Endangered Species Act (ESA) with U.S. Fish and Wildlife Service (USFWS) to develop routing, design, and construction schedules to avoid and minimize impacts to nesting migratory birds, bird habitats, and endangered species. Conservation measures to address impacts to ESA protected species are included in the final BA from the proposed Project and the associated distribution lines that resulted from consultation under Section 7 of the ESA regarding the American burying beetle (see Section 3.8 and Appendix T of the EIS).

If applicable, Keystone would develop a Migratory Bird Conservation Plan in consultation with USFWS to avoid, minimize, and mitigate for impacts to migratory birds and migratory bird habitats. While some migratory birds would likely be harassed, injured, or lost during pipeline and distribution line construction and operation; USFWS does not have a process for allowing unavoidable and unintentional incidental take of migratory birds. Keystone would implement all reasonable and prudent measures identified during consultations with USFWS to avoid take of migratory birds, bald eagles, golden eagles, and endangered species and to avoid or mitigate loss, destruction, or degradation of migratory bird habitat.

See Consolidated Response ENV-4 for information regarding migratory bird issues in relation to Canadian oil sands production.

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