Exhibit G

TransCanada
In business to deliver

October 10, 2008

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Jeff Wiese
Associate Administrator for Pipeline Safety
U.S. Department of Transportation
Pipeline and Hazardous Materials Safety Administration
East Building, 2nd Floor
1200 New Jersey Ave., SE
Washington, DC 20590

Re: Application for Special Permit to Design, Construct and Operate Proposed NPS 36-inch TransCanada Keystone XL Pipeline Project at 80% Specified Minimum Yield Strength (SMYS)

Dear Mr. Wiese,

In June 2008, I wrote to you on behalf of TransCanada Keystone Pipeline LP (Keystone), introducing Keystone's proposal to construct and operate a new 2,000-mile, NPS 36-inch pipeline from Hardisty, Alberta to the Port Arthur and east Houston areas of Texas. Also discussed was Keystone's intention to adopt design, construction and operating practices in conjunction with the PHMSA-2006-26617 special permit safety features of the NPS 30-inch Keystone Pipeline and the NPS 36-inch Cushing Extension Pipeline.

After subsequent discussions between my technical Staff, Mr. Alan Mayberry and Mr. Max Kieba, I am pleased to submit Keystone XL's application for a Special Permit to design, construct and operate the proposed NPS 36-inch pipeline using a design factor and operating stress level of 80 percent of the steel pipe's SMYS.

TransCanada is confident the Keystone XL oil pipeline can be safely and reliably operated at the higher design factor in an environmentally responsible manner and are requesting a waiver of compliance from 49 C.F.R. § 195.106. We would appreciate the opportunity to meet with you to further progress consideration and approval of our application.

Best regards,

Robert Jones, P.Eng.
Vice President, TransCanada Keystone Pipeline LP

cc:Bill Gutte, Deputy Associate Administrator, PHMSA
Alan Mayberry, Director – Engineering & Emergency Support, PHMSA
John Gale, Director – Regulations, PHMSA
Ivan Huntoon – Director, Central Region, PHMSA
Rodrick Seeley – Director, South West Region, PHMSA
Chris Hoidal – Director, Western Region, PHMSA

UNITED STATES OF AMERICA
BEFORE THE
PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION

Petition of TransCanada Keystone Pipeline, LP For a Special Permit To Design, Construct And Operate A New 36-inch Crude Oil Pipeline At Design Pressures Up To 80 Percent SMYS And Request For Expedited Consideration

<u>October 10, 2008</u>

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Petition of TransCanada Keystone Pipeline, LP, For Waiver To Design, Construct And Operate A New 36-inch Crude Oil Pipeline At Design Pressures Up To 80 Percent SMYS And Request For Expedited Consideration

Pursuant to Section 60118 of the *Pipeline Safety Act* , 49 U.S.C § 60118, TransCanada Keystone Pipeline, LP (Keystone) hereby files with the Pipeline and Hazardous Materials Safety Administration (PHMSA) this request for a special permit relative to the regulations in 49 C.F.R. § 195.106 (2005), so as to permit Keystone to design, construct and operate the Keystone XL Pipeline, at hoop stresses up to 80 percent of the specified minimum yield strength (SMYS) for mainline pipe totaling approximately 1,375 miles of new 36-inch pipeline A special permit is requested for all mainline and extension facilities other than those described below:

a. pipeline segments that will operate in high consequence areas described as High Population Areas and Other Populated Areas as defined by 49 CFR §195.450;
b. pipeline segments that will operate in Commercially Navigable Waterways and in waterbodies greater than 100 feet in width of the stream as defined by 49 C.F.R. §195.450
c. pipeline segments that will operate at highway, railroad and road crossings; and
d. pump station, mainline valve, pigging, and measurement piping.

These facilities will be designed, constructed and operated in accordance with 49 C.F.R. § 195.106 (2005) at hoop stresses up to 72 percent of the SMYS

1. Project Overview

In the United States, the Project will consist of 1,375 miles of new 36-inch diameter being developed by TransCanada Keystone Pipeline LP (Keystone) a partnership owned equally by subsidiaries of TransCanada Corporation and ConocoPhillips Company. TransCanada PipeLines Ltd. ("TransCanada") will be the operator of the Keystone XL Pipeline. TransCanada has more than 50 years experience in the responsible development and reliable and safe operation of North American energy infrastructure including natural gas pipelines, power generation, gas storage facilities, and projects related to oil pipelines and LNG facilities. TransCanada owns and operates a natural gas pipeline network of more than 36,500 miles, which taps into virtually all major natural gas supply basins in North America. TransCanada transports the majority of Western Canada's natural gas production across the North American continent to markets in the Untied States and Canada. Furthermore, TransCanada is in the execution phase of the $5.2 Billion Keystone Pipeline project, a major crude oil pipeline project. The Mainline segment of the Keystone project, which extends from the North Dakota-Canada border to Wood River and Patoka, Illinois; and the Cushing Extension, which extends from Steele City, Nebraska, to Cushing, Oklahoma, are on schedule for completion in 2009 and 2010, respectively.

TransCanada has total assets of approximately U.S. $32 Billion. For the year ended December 31, 2007, TransCanada had a net income from continuing operations of approximately U.S. $1.2 Billion and cash flow of approximately U.S. $2.84 Billion. Attached as Appendix A is a summary document demonstrating TransCanada's fitness to develop, construct, and operate the Keystone XL Project as a major cross-border pipeline system.

TransCanada Keystone Pipeline, L.P. is 50 percent owned by ConocoPhillips Company. ConocoPhillips is the third-largest integrated energy company in the United States, based on market capitalization, as well as reserves of oil and natural gas. Worldwide, of non-government-controlled companies, ConocoPhillips is the sixth-largest holder of proved reserves and the fifth-largest refiner. Headquartered in Houston, Texas, ConocoPhillips operates in nearly 40 countries and has approximately 33,100 employees worldwide. The company has assets of $190 billion. ConocoPhillips stock is listed on the New York Stock Exchange under the symbol "COP."

ConocoPhillips operates more than 11,000 miles of pipelines and more than 60 storage terminals in the United States. ConocoPhillips transports both raw and finished petroleum products, including crude oil, propane and refined products such as gasoline, diesel and jet fuel.

The Keystone XL Pipeline project will address the need for additional pipeline capacity to transport increasing crude oil production from Alberta to markets in the United States. The project will be designed to transport up to approximately 900,000 barrels per day (bpd) of crude oil received from an oil hub near Hardisty, Alberta, Canada to existing terminals in the Nederland and Houston, Texas areas. A map of the project is included in Appendix C.

The timely construction of the Keystone XL Pipeline is essential for the delivery of new crude oil supplies from the Western Canadian Sedimentary Basin (WCSB) to meet growing U.S. demand for crude oil from stable, secure, non-offshore crude oil supplies and to provide export pipeline capacity for increasing WCSB crude oil supply. (Further detailed discussion of the purpose and need for the Keystone XL Pipeline project is provided in Appendix B, attached.) According to the Canadian Association of Petroleum Producers' forecast of crude production based on approved and planned projects, the total Alberta production volume continues to increase thereby requiring additional pipeline capacity[1]. Keystone's analysis of this same data supports this conclusion and has led Keystone to target completion of the pipeline by 2012. Keystone is seeking expedited consideration of its special permit request with a final determination by no later than March 1st, 2009 to allow Keystone sufficient time to finalize project-specific specifications for the steel plate order and fabrication of pipe to meet a Q2 2011 in-service date for the pipeline section downstream of Cushing, Oklahoma and an in-service date of Q1 2012 for the pipeline section upstream of Steele City, Nebraska.

In the United States, the Project will consist of 1,375 miles of new 36-inch diameter pipeline, in three segments:

- The approximately 850-mile long "Steele City" segment from the US border to Steele City, Nebraska;
- The approximately 478-mile long "Gulf Coast" segment from Cushing, Oklahoma to Nederland, Texas; and
- The approximately 47-mile long "Houston Lateral" segment from Liberty County, Texas, to the Moore Junction area in Harris County, Texas.

There will be 33 pump stations along the pipeline route in the US. The pipeline will connect with the Keystone Pipeline project at the northernmost point of the Keystone Cushing Extension at Steele City, Nebraska, and at the southernmost point of the Keystone Cushing Extension at its Cushing, Oklahoma terminus. Attached as Appendix C hereto are detailed route maps depicting the preferred route of the proposed Project.

In Canada, approximately 327 miles of new 36-inch pipeline will be constructed from Hardisty, Alberta to Monchy, Saskatchewan where it will cross into Phillips County, Montana. As discussed below at Section VII, review and approval of the proposed Canadian facilities will

[1] CAPP June 2008 Crude Oil Forecast Markets and Pipeline Expansions

be subject to the jurisdiction of the Canadian National Energy Board ("NEB") as well as various local, municipal, and provincial authorities.

On September 19, 2008, Keystone filed an application with the United States Department of State (DOS) for a Presidential Permit authorizing the construction, operation, and maintenance, of pipeline facilities for the importation of crude oil to be located at the border between the United States and Canada. As part of its application, Keystone filed a preliminary environmental report for the U.S. segment of the project to permit the Department of State and other affected agencies to determine the lead agency for the NEPA review of the project. Keystone will submit supplemental environmental reports in November 2008 and June 2009. Keystone anticipates receiving necessary regulatory approvals by Q2 2010 to meet its targeted in-service dates of Q2 2011 and Q1 2012.

2. Pipeline Design, Construction, and Operations

The Keystone XL Pipeline Project will be designed and constructed in accordance with the requirements of 49 C.F.R. § 195 and ASME B31.4. Keystone will utilize TransCanada's design and construction standards for the Project. These standards meet or exceed the requirements of 49 C.F.R. § 195 and ASME B31.4, and maintain and enhance the reliability and safety of the pipeline while reducing construction costs. The following discussion describes the principle features of the proposed design and construction of the Keystone XL pipeline. A summary table of the factors that differ between the Keystone Pipeline Special Permit and the Keystone XL design parameters is provided in Appendix D.

2.1. Pipe Specification

Keystone will purchase pipe utilizing X-70 or X-80 grade steel from technically pre-qualified pipe mills. TransCanada's specification will exceed the requirements of 49 C.F.R. § 195, Subpart C, which incorporates API 5L by reference. TransCanada will specify steel chemistry criteria for line pipe in order to maximize the steel's toughness and weldability, thereby reducing defective fabrication welds and the pipeline's susceptibility to third party damage. The following analysis demonstrates where TransCanada will exceed the requirement of API-5L for crude oil pipelines:

- *Pipe - Carbon Equivalent* - Pipe carbon equivalent will be 0.22% for grade X80 and 0.20% for X70, compared to API-5L maximum carbon equivalent of 0.25%, and the maximum carbon percentage will be limited to 0.1% compared to 0.24% in API 5L to improve weldability and reduce the potential for defective welds during the fabrication process.
- *Pipe – Puncture Resistance* - In an industry survey, it was found that about 98% of excavators in North America have a maximum digging force of less than 35 tons, and none have digging force exceeding 40 tons[2]. Based on Keystone design parameters, the puncture resistance, as calculated using the puncture resistance formula[1] shown in Appendix E, will be greater than the minimum desirable resistance of 35 tons [3], and will in fact exceed 40 tons for all pipe sizes, design factors and grades.
- *Pipe – Longitudinal Weld Seams* - Longitudinal seam weld procedure qualification tests will include at least two microhardness traverses across the weld, heat affected zone, and parent material. Each traverse will consist of a minimum of two readings taken within the weld, a minimum of two readings on each side of the weld in the heat-affected zone, and a minimum of two readings on each side of the weld in the parent metal. A maximum weld seam and heat affected zone hardness (during weld procedure qualification testing) to prevent hydrogen assisted cracking. Longitudinal weld seams will be inspected for

[2] PRCI PR-244-9729 Reliability-based Prevention of Mechanical Damage to Pipelines

[3] J.Kiefner. Impact of 80% SMYS Operation on Resistance to Third Party Mechanical Damage., March 2006

longitudinal and transverse imperfections by an ultrasonic method, or by a combination of ultrasonic and film radiographic or non-film radiographic imaging methods. The complete volume of weld metal and heat-affected zones in the weldment will be inspected, including the mid-wall for radial imperfections. The non-destructive inspection will be completed after the mill hydrostatic test.

- *Pipe – D/T ratio* - The D/T ratio is less than 100 and is noted as follows:

Diameter	API 5L	Pressure	Wall Thickness based on 80SMYS	D/T Ratio
OD(in)	Grade	(psi)	(in)	
36	80	1440	0.405	88.8
36	70	1440	0.463	77.7

- *Pipe – Mill Inspection Plate/Coil/Pipe Rolling* - TransCanada requires the manufacturer to have a written method of monitoring the severity of centerline segregation to minimize the extent of segregation. TransCanada's specification sets stringent dimension controls rejecting pipe with wall thickness less than 95% of the specified wall thickness compared to the API-5L limit of 92% of the specified wall thickness.
- *Pipe – Mill Hydrostatic Test* - Mill hydrostatic testing will be performed to 95% SMYS held for a minimum of 10 seconds, exceeding the strength test requirements of API -5L.
- *Pipe – Mill UT Inspection and Flaw Acceptance* – TransCanada's specifications have more stringent requirements for mill UT inspection, flaw acceptance criteria, and calibration frequency.

2.2. Fracture Control Plan

Line pipe for the Keystone XL Pipeline project will be manufactured according to API-5L PSL 2. The pipe will be NPS 36 API 5L Grade X70 or X80 submerged arc welded pipe. All pipe will meet or exceed the requirements for installation, testing and operation in the latest edition of ASME B31.4.

TransCanada will require Charpy impact testing and Drop Weight Tear Testing on the pipe body to ensure fracture resistance, in accordance with supplementary requirements SR5B, SR6 and SR19 and as per the Keystone Pipeline Special Permit PHMSA-2006-26617 Condition 4.

2.3. Pipe Coating and Corrosion Prevention

In addition to meeting the requirements set out in 49 CFR §195, TransCanada will follow the requirements of the latest editions of NACE International's Recommended Practice, RP01-69, Control of External Corrosion on Underground or Submerged Metallic Piping Systems along with NACE International's Test Methods, TM01-4-97-97, Measurement Techniques Related to Criteria for Cathodic Protection on Underground or Submerged Metallic Piping Systems.

- *Coating – Pipe* - The pipe will be externally coated with plant applied fusion-bonded epoxy (FBE), girth welds will be coated with field applied FBE or liquid epoxy.
- *Coatings – Field Welded Joints* - Field welded joints will be prepared and coated with FBE or liquid epoxy in accordance with TransCanada coating specifications.
- *Coatings – Directional Drills/Slick Bores* - Line pipe installed in a bored or directional drill crossing will be coated with FBE and an additional protective abrasion-resistant FBE outer coating or liquid epoxy.
- *CP Systems and Induced AC - Mitigation during Construction* - The pipeline system will include an impressed current cathodic protection (CP) system in accordance with 49 C.F.R. § 195.563 which will be progressively activated during the construction phase. Test stations will be attached to the pipeline at intervals averaging one mile, and not exceeding two miles, and at public road and railroad crossings. Test leads and CP bond wires will also be installed on the Keystone XL pipeline at foreign pipeline crossings and

installed on to the foreign pipeline being crossed, when approved by the owner of the foreign pipeline. The proposed Keystone XL pipeline is co-located with 38 miles of high voltage power transmission lines and exposure to induced alternating current (AC) electric currents is therefore minimal. Corrosion due to AC interference is very rare. Research by PRCI (GRI 8187) concluded AC corrosion is possible only in special circumstances of current density and holiday size. The concern with AC interference is personnel safety (step and touch potentials). Keystone will install CP and stray current mitigation facilities during pipeline construction. The requirements of OSHA 1910.269(n) Grounding for Protection of Employees, 1910.269 Appendix C Protection from Step and NACE PR-0177 Mitigation of Alternating Current and Lightning Effects on Metallic Structures and Corrosion Control Systems will be met. Specifically, step and touch potentials will be maintained at no more than 15 volts RMS AC. During operation, the effectiveness of the original mitigation designs will be evaluated and modifications made as required.

- *Coatings – Temperature Rating* - The pipeline will operate at a minimum value temperature of 32°F, and a maximum value temperature of 158°F. The FBE (203°F) and liquid epoxy coating systems (185°F) are rated above these respective operating temperatures. Lab test results are contained in Appendix J.
- *Coatings – Cased Crossings* - All railroads, highways and roads will be crossed without casings unless otherwise requested and will minimize carrier pipeline corrosion due to mechanical or electrolytic shorts developed by casings over time.
- *Coatings – Telluric Currents* - Telluric currents are currents flowing in the crust of the planet earth as a result of inductive and capacitive effects from the aurora borealis. The aurora borealis is produced when solar wind charged particles are trapped by the earth's magnetic field. TransCanada has been doing research on the effects of telluric currents

on pipelines with Carlton University and the Geomagnetic Laboratory of Natural Resources Canada for over 10 years. TransCanada originally performed research on telluric currents as part of the pre-engineering for the Alaska Highway Gas Pipeline Project in the late 1970's and early 1980's. Earth magnetic fields can make it difficult to perform CP surveys, but have little to no effect on pipeline integrity. Methods for correcting for earth currents are used on a regular basis in CP surveys at TransCanada. The methodology employs a satellite based CP power source interruption system which is synchronized with stationary reference cell data collectors on both sides of the survey region. Baseline ground potentials are recorded in sync with the pipe-to-soil survey potentials in order that the CP survey potential readings can be corrected for the deviations produced by telluric currents.

2.4. Welding and Non Destructive Testing

Keystone will perform all welding with fully qualified welding procedures and employ fully trained and qualified welders. The Keystone XL Pipeline Project will assure that all welds are 100 percent nondestructively tested using automated ultrasonic inspection or radiographic inspection by qualified technicians and procedures and in conformance with the weld acceptance criteria of API 1104 and supplemental requirements set out in project specific welding procedures. The automated ultrasonic inspection procedures will include measures for assessing stacked defects, thus eliminating the possibility of through-wall leaks.

- *Fittings/Flanges/Gaskets* - Keystone requires components (fittings, flanges, valves) to be designed to the applicable codes with additional company requirements for carbon equivalent control, weldability, dimensional and fracture resistance. The design of the components will take into account the applicable pressure and temperature ratings in the codes. The welding of these materials will be completed with qualified welding procedures using a specified preheat and inter pass temperature range.

2.5 Additional Protection

Keystone will design the pipeline to exceed the depth of cover requirements for installation of new oil pipelines set out in 49 C.F.R. § 195.248, Part D. Keystone will generally provide 4 feet of cover over the pipeline as compared with the 30 inch minimum required by CFR 195. Increased signage and warning tape will be installed in areas where there is nominally less than 4 feet of cover such as in consolidated rock areas. Depth of cover will be a minimum of 5 feet below the bottom of road ditches and water bodies, which includes rivers, creeks, streams, ditches and drains.

2.6. Hydrostatic Testing

Before putting the pipeline into service, it will be hydrostatically tested to exceed the strength test requirements of 49 C.F.R. § 195.304, to not less than 100 percent of SMYS at the high point in the test section, held for a minimum of 4 hours. This provides maximum assurance that any unacceptable defects are removed from the pipeline prior to service.

- *Test Failures* - Any test failures will be reviewed for root cause analysis and will have metallurgical examination testing conducted. A report on the findings will be submitted to PHMSA.

2.7. Internal Inspection

After final backfill, hydrostatic testing, dewatering and drying, and prior to swabbing and commissioning the pipeline for oil service, the pipe will be inspected internally using a calliper tool to detect reductions in diameter which may have occurred during the lowering and backfill process.

2.8. Quality Assurance Plan

Keystone will ensure pipe quality by implementing the following steps:

- Purchase pipe only from pre-qualified vendors according to TransCanada's vendor qualification procedures.
- All pipe mills selected will then be subjected to a formal technical qualification program and audit to ensure registered quality systems, inspection and test plans are in place and followed.
- Specification review meetings will be held with each vendor prior to production to review the key specification requirements.
- During production, third party surveillance will be present in the pipe mill to monitor and assess the manufacturing and stock pile of pipe.
- Record details of rolling practices and production heat numbers used for each pipe joint will be required to ensure root cause analysis can later be performed to determine the extent of potentially affected pipe in the event material deficiencies are discovered.
- Test coating systems to ensure they meet the strict material property requirements of NACE PR-0394 Application, Performance, and Quality Control of Plant-Applied, Fusion-Bonded Epoxy External Pipe Coating. Cure, flexibility, impact resistance, blast profile, interfacial contamination, thickness and cathodic disbondment resistance are some of the properties evaluated.
- Perform a plant trial to ensure that the coating factory or application plant is capable of applying the coating such that the requirements of the above referenced specifications are met on a consistent basis in the finished product.
- Perform regular non-destructive and destructive tests during plan application on coated pipe samples obtained from the process to confirm the coated pipe meets the specified

requirements. Unacceptable coated pipes are rejected and run through the process again until an acceptable product is produced.

- Inspect the coated pipe for "holidays" or coating defects prior to leaving the plant and repair any deficiencies found.
- Take care in handling the pipe in stockpiling, transportation and stringing to minimize any coating damage that may occur.
- Inspect the pipes after welding for "holidays" and again, all deficiencies are repaired prior to backfilling.
- Coat girth weld areas in the field using coating materials that have been previously tested and approved to provide acceptable levels of long term performance. The application procedures used in the field have been tested and proven to provide the level of performance required when used with an approved coating material. The field applicators are trained and tested to prove they are capable of following the application procedure. Periodic process parameter and coating cure tests ensure that the girth weld coating is properly applied and will provide the high degree of protection required. Welds with unacceptable cure or process parameters are cleaned off and recoated.

TransCanada's experience has shown that following this proactive approach to preventing and detecting coating disbonding in the factory and the field results in pipelines with a high degree of integrity and safety. To date, TransCanada has not experienced integrity issues with Fusion Bond Epoxy coated pipelines, some of which have been in service for 28 years. Keystone will take additional steps to ensure a higher quality pipe coating than is required by the latest editions of NACE International's Recommended Practice, RP01-69 and Control of External Corrosion on Underground or Submerged Metallic Piping Systems.

Keystone will have qualified inspectors to ensure quality standards are maintained during pipe transportation, stringing, welding, bending, coating, lowering-in and backfill.

- *Pipe Transportation* - Pipe will be transported as per API 5LW and API 5L1.
- *Field Bends* - TransCanada will require padded bending machines to protect the pipeline coating during field bends. The maximum bend radius allowed will correspond to 1.5° per pipe diameter permanent strain. All field bends are visually inspected to determine if any wrinkles have occurred during bending.

A diagram illustrating Keystone's Quality Assurance Plan is provided in Appendix F.

2.9. Operational Control Systems

Supervisory Control and Data Acquisition (SCADA) System

Keystone will utilize a comprehensive SCADA system situated within TransCanada's Operations Control Center (OCC) to remotely monitor and control the entire pipeline. The SCADA system design for the Keystone Pipeline and the SCADA related Conditions 25-32 of the Keystone Pipeline Special Permit PHMSA-2006-26617 will serve as the platform for the Keystone XL SCADA system

SCADA – Mainline Valves & Set Points

In addition, remotely controlled mainline valves including those associated with high consequence areas will be monitored by the SCADA system. In the event of a valve closure, the SCADA system generates an automated shutdown of pumping facilities at specific pump station locations. In order to ensure the Keystone XL pipeline system does not operate under two-phase flow conditions, pressure transmitters will be installed at column separation sensitive locations and utilized to alert OCC Operators of an impending event.

Keystone will place emergency flow restricting devices and/or remotely controlled valves on either side of pipeline segments containing unusually sensitive areas as defined in 49 C.F.R. § 195.6 including drinking water and ecological resource areas.

Pipeline Hydraulics Model and OCC Operator Simulator

Keystone will develop a pipeline transient hydraulic system model during the detailed engineering stages of the Keystone XL Pipeline project. This model will be configured to provide a real time replica of the Keystone Pipeline system including, mainline piping configuration, pump station equipment and piping configuration, fluid characteristics and other pertinent operating data. A comprehensive review of the entire pipeline system, under both steady state and transient hydraulic conditions, will then be performed to identify issues and confirm equipment requirements. This model will then be utilized to design pipeline pressure control systems and to further analyze and test various strategies and control systems to ensure compliance with all applicable regulations.

Following completion of these activities, the model will be further enhanced to provide a pipeline simulator capable of replicating operation of the Keystone XL pipeline system on a real time basis. The pipeline simulator will interface with the applicable SCADA control systems through actual interactive displays available to the OCC Operators, to simulate real operation and control of the pipeline system. Specific OCC procedures will then be developed, tested and further refined through use of this system. The pipeline simulator will also be utilized to provide near real time training of the OCC Operators under a variety of conditions, including detection and mitigation of leaks and other abnormal pipeline operating conditions in order to familiarize personnel with such conditions and ensure the appropriate response. The simulator model will be verified and adjusted as necessary during the initial stages of actual pipeline operation.

Leak Detection System

Keystone will employ a computational pipeline monitoring (CPM) Leak Detection System (LDS) to aid in the detection of hydraulic anomalies in pipeline operation. The LDS will comply with 49 C.F.R. § 195.134 and 195.444 and follow API 1130 - Computational Pipeline Monitoring for Liquid Pipelines. The system will be configured in a manner capable of alarming the OCC Operators through the SCADA system and will also provide the OCC Operators with a comprehensive assortment of display screens for incident analysis and investigation. The LDS hardware will be comprised of both a main and fully redundant hot standby system installed at the OCC and the Back–up Control Center (BCC).

The LDS and associated transient hydraulic model will be provided with information related to fluid characteristics and other SCADA data including, pumping station suction and discharge pressure, flow rate at injection and delivery locations as well as intermediate locations and pipeline temperature. An on board batch tracking system will be utilized to enhance detectable limits and assist with incident analysis and investigation.

The detectable limits of the LDS will be established once the system is in service and will be tuned and optimized as operating experience is gained. The initial limit of the LDS is expected to be 2 percent of normal flow, improving over time as operating experience is gained. Detection thresholds that result in alarms directed to the OCC Operators will be established on a time dependant basis, corresponding to the volume of the suspected leak. Routine testing will be performed to validate system performance. During design, Keystone will define leak detection criteria including the minimum size of leak to be detected, leak location accuracy and response time for various pipeline conditions.

The overall design of the LDS will be robust to ensure continued operation with a loss of instrument equipment alarm and other events such as communications outages. Although a corresponding increase in leak volume detection thresholds would be temporarily experienced during these events, the system would remain operational in a downgraded mode.

Operations Control Center Procedures

An Operations Control Center (OCC) Procedures Manual will be developed, incorporating the requirements for Operator Qualification identified in 49 C.F.R. § 195, Subpart G, and incorporating the leak detection requirements as found in Annex E of CSAZ662-07. The comprehensive slate of existing TransCanada policies and procedures will be utilized where applicable and supplemented to address liquid pipeline operations.

This Manual will provide the OCC operators with both procedures and guidelines for normal and abnormal events to ensure events are managed consistently within the OCC. Key areas to be covered under normal procedures will include pipeline start up, shutdown and swing procedures. Areas to be covered within abnormal procedures will include response to pumping station local alarms, including fire and gas detection, as well as response to LDS alarms and other observed suspected leak conditions.

The OCC operator will have authority to execute a pipeline shutdown and to initiate a spill response as outlined within the OCC Procedures Manual and in accordance with the Keystone XL Oil Spill Response Plan. The Keystone XL Oil Spill Response Plan will meet the requirements of 49 C.F.R. §194 and §195 and will be submitted for approval prior to in-service of the pipeline.

OCC procedures will include shift change procedures, implementation of individual controller log on, a secure operating control environment, the ability to make modifications and test these modifications in an off-line mode, table top exercises, periodic review and auditing of alarms for false alarm reduction , near misses or lessons learned criteria and work load concerns.

Keystone will work with industry to move forward with the recommendation found in NTSB/SS-05/02.

The OCC will be staffed by qualified (as per ASME B31Q) Control Center operators on a 24-hour per day, 7-day per week basis. When operators are required to respond to "800 calls", specific training covering the proper procedures for responding to emergency calls and education on the types of RP1162 communications will be provided. Operators will be provided on the job training and performance reviews that include measurement of alarm or event response time. Where appropriate, operator training will incorporate field visits to gain familiarity with equipment.

2.10 Pipeline Integrity

The Keystone XL pipeline will be designed such that all mainline piping is "piggable." Piping sections will be provided with permanent pig launcher and receiver facilities at intervals suitable to the effective inspection of the pipeline system.

- **Mechanical damage immediate failure** - Notwithstanding that the puncture resistance at both design factors significantly exceeds the maximum digging force of any excavators active in the United States, immediate failure resulting from mechanical damage will be addressed by burying the pipeline with a minimum of four feet of cover. Keystone XL will also provide increased signage and warning tape in areas where there is nominally less than 4 feet of cover, to achieve an 80% reduction of line strike frequency in undeveloped areas, 41% in developed areas and 20% reduction in areas with close spaced signage and warning tape[4].
- **Mechanical damage and delayed fatigue failure** due to mechanical damage will be addressed utilizing the increased depth of burial, signage and warning tape described

[4] See Appendix G, Table 2

above. Together with baseline MFL inspection (capable of gouge detection) within three years of commencement of operations as per Condition 42 of the Keystone Pipeline Special Permit PHMSA-2006-26617.

- **Fatigue life for manufacturing flaw** will be addressed by monitoring and recording operating pressure data from the pipeline to construct actual pressure spectrum. To provide a high confidence in Keystone's fatigue life calculation, no time averaged data will be used. Fatigue life will then be reassessed annually with results reported to PHMSA for the first five years of operation. Fatigue safety will be further ensured by utilizing a crack inspection tool at the predicted fatigue life with the appropriate safety factor to ensure that any cracks present are detected and eliminated before the onset of rapid growth.
- **Control of initial manufacturing flaw size** will be addressed utilizing Keystone's proprietary specification. This specification is more restrictive and comprehensive than API 5L PSL 2 and involves increased qualification, testing, inspection, surveillance and documentation requirements. These requirements ensure that initial flaws that exceed Keystone's stringent specification do not escape the mill quality management system. In addition, examination of selected seam welds on delivery to the field will confirm the effectiveness of Keystone's quality management system for addressing transportation fatigue.
- **External corrosion** will be addressed by utilizing high performance coatings on the mainline pipe, including girth welds, with additional protective abrasion-resistant coatings where required (e.g. bored crossings, HDD). In addition the cathodic protection system will be installed and progressively activated during the construction phase (instead of within one year of operation) to control corrosion immediately and thereby reducing any

initial growth. Further, Keystone's mill wall thickness tolerance will be more stringent than that required by API 5L, resulting in an increased initial minimum wall thickness.

- **Internal corrosion** will be addressed utilizing a more stringent sediment and water tariff requirement to reduce the corrosivity of the transported liquid, and ultimately resulting in lower corrosion rates. Internal corrosion will also be addressed through a pipeline design resulting in turbulent flow in all flow regimes to prevent the drop out of water or solids and, as set out above, through the use of a more stringent mill wall thickness tolerance. In addition, Keystone proposes to utilize a cleaning program to confirm the effectiveness of its internal corrosion program. Effectiveness of the internal corrosion program will be reported to PHMSA for the first five years of operation. Further detail is offered in Appendix G.

3. Petition for Special Permit

Keystone requests a special permit in relation to 49 C.F.R. § 195.106, to the extent necessary to permit Keystone to design, construct, and operate the approximately 1375 miles of the Keystone XL mainline pipe at hoop stresses up to 80 percent of the SMYS in the United States. Keystone's request for a special permit applies to all Keystone XL facilities other than those described below:

a. pipeline segments that will operate in high consequence areas described as High Population Areas and Other Populated Areas as defined by 49 C.F.R. § 195.450;
b. pipeline segments that will operate in Commercially Navigable Waterways as defined in 49 CFR § 195.450 and in waterbodies greater than 100 feet in width of the stream as defined by 49 C.F.R. §195.450;
c. pipeline segments that will operate at highway, railroad and road crossings; and
d. pump station, mainline valve, pigging, and measurement piping.

These facilities will be designed, constructed and operated in accordance with 49 C.F.R. § 195.106 (2005) at hoop stresses up to 72 percent of the SMYS.

Under Section 60118 of the *Pipeline Safety Act*, PHMSA may grant a special permit in relation to any regulatory requirement if granting the waiver is "not inconsistent with pipeline safety." 49 U.S.C. § 60118. The special permit that Keystone seeks in this petition is not inconsistent with pipeline safety. As demonstrated in the chart included in Appendix D, the standards that Keystone will use to design and construct the Keystone XL Pipeline will meet or exceed the requirements of DOT regulations and will result in a higher degree of pipeline safety than the minimum safety standards provided in the regulations.

Accordingly, Keystone respectfully requests that PHMSA approve the special permit in relation to the requirements of 49 C.F.R. §195.106 to allow the design, construction, and operation of the Keystone XL Pipeline at hoop stresses up to 80 percent SMYS for mainline pipe totalling approximately 1,375 miles. Keystone does not seek a special permit in relation to, and will comply with, all other applicable requirements of 49 C.F.R. §195.

4. Public Policy Benefits

The timely construction of the Keystone XL Pipeline is essential to transport incremental crude oil production from the Western Canadian Sedimentary Basin (WCSB) to meet growing demand by refineries and markets in the U.S. As, noted the Project would commence at the crude oil supply hub near Hardisty, Alberta, Canada and terminate near existing crude oil storage terminal facilities near Nederland and Houston, Texas. Construction of the Project will serve the national interest of the United States by providing US refineries and markets with access to a substantial, secure, and reliable supply of Canadian crude oil to meet increasing US demand for petroleum products. The need for the project is dictated by a number of factors including:

- Increasing crude oil demand in the United States;
- Decreasing domestic crude supply in the United States;
- An opportunity to reduce US dependence on foreign offshore oil supply through further supply diversification to stable, secure Canadian crude supplies;
- Increasing WCSB crude oil supply; and
- Demonstrated shipper interest in the Project.

Further detailed discussion of the purpose and need for the Keystone XL Pipeline project is provided in Appendix B, attached.

Allowing Keystone to design, construct, and operate the Keystone XL Pipeline at a higher design factor will increase the public benefits accruing from the project. PHMSA, in issuing the Notice, has recognized the many benefits of an increase in design factor for natural gas pipelines. Pipeline operators continually explore ways to reduce the cost of new pipelines, or increase the efficiency of existing pipelines, without affecting reliability or safety.[5] Keystone agrees and submits that the many benefits identified by PHMSA are applicable also to an increase in design factor for crude oil pipelines, particularly for new crude oil pipelines. Approval of the petition to construct and operate the Keystone XL Pipeline at 80% SMYS will lower the amount of steel required for the project. This reduction results in reduced materials, transportation and construction costs. The toll structure of the Keystone XL project is such that a reduction in project capital costs is passed on to the shippers. The ability to competitively ship crude oil to existing refining capacity provides an economic and security benefit for the refiners and downstream consumers.

[5] Notice, 71 Fed. Reg. at 977

5. Request for Expedited Consideration

Keystone requests expedited consideration and approval by PHMSA of its application. Keystone requires PMHSA approval by March 1st, 2009 to provide it with sufficient time to finalize pipeline specifications for the steel plate order and fabrication of pipe to meet the required 2011 and 2012 in-service dates.

CONCLUSION

For the reasons set forth above, Keystone's requested special permit in relation to 49 C.F.R. § 195.106 is not inconsistent with pipeline safety. Keystone therefore respectfully requests PHMSA to:

a. approve the special permit in relation to of 49 C.F.R. § 195.106, so as to permit Keystone to design, construct, and operate the Keystone XL Pipeline at hoop stresses up to 80 percent of SMYS for approximately 1,375 miles in the United States; and

b. expedite its consideration of this petition for special permit and issue an order approving Keystone's petition by March 1st, 2009.

Respectfully submitted,

Robert Jones P.Eng.

Vice President TransCanada Keystone Pipeline LP

Dated: October 10th, 2008

Appendix A

About TransCanada

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About TransCanada

TransCanada is a leader in the responsible development and reliable operation of North American energy infrastructure. TransCanada's pipeline network of more than 36,500 miles transports the majority of western Canada's natural gas production across the North American continent to markets in the United States and Canada. TransCanada also is part owner of approximately 4,800 miles in additional pipeline infrastructure in the U.S. and Canada and serves as operator of some of those systems.

Our transmission value proposition encompasses unconstrained market/supply access, offering speed, flexibility, diversity and choice to our customers. This value is reflected in a competitive cost structure and tolls, market-responsive products and services and world-class reliability.

We are a prominent North American pipeline project developer, builder and operator, based on sound expertise in all aspects of pipeline development – from the preliminary phase of engineering planning and regulatory approvals through to construction, commissioning, operation and customer service.

The excellence in operations and technological innovation evidenced on our pipeline systems puts TransCanada firmly in the place of an industry leader. We measure operational excellence in terms of the efficiency and cost-effectiveness achieved on our systems. Our pipeline development record also exhibits our strong acceptance of social responsibility and commitment to maintain environmental integrity in the communities along our pipeline systems.

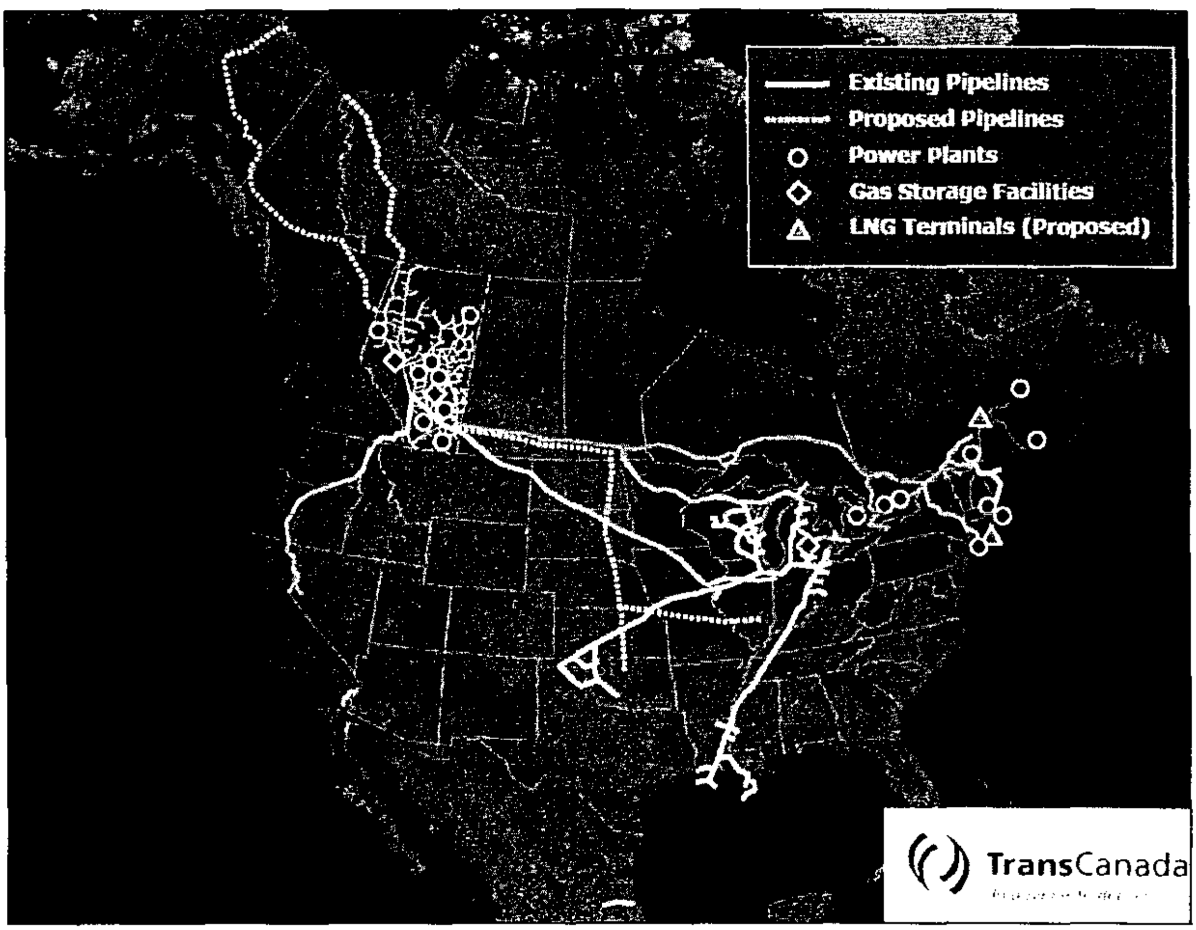
TransCanada is also an emerging player in the North American power market. Through our power business unit, we own, operate and control 10,900 MW of power generation equipment in Canada and the northern United States.

TransCanada has approximately 3,800 employees who provide industry-leading expertise in pipeline and power operations.

TransCanada has total assets of approximately $32 billion. For the year ended December 31, 2007, TransCanada had net income from continuing operations of approximately $1.0 billion and cash flow of over $2.5 billion.

Gas Transmission Experience

TransCanada PipeLines Limited is one of North America's leading gas transmission companies. Our pipeline network transports the majority of western Canada's gas production to markets across the continent. We have focused on optimizing our pipeline network by developing new products and services, better access to markets and competitive and innovative approaches to meeting customers' needs. TransCanada's transmission network gives customers reliable access to domestic markets and key export markets in the Pacific Northwest, Midwest and U.S. Northeast.



Liquids Pipeline Experience

TransCanada has significant experience in the design and construction of crude oil pipelines in North and South America.

TransCanada was a 50% joint venture partner with Alberta Energy Company in both ownership and operations from 1995 to 2000 on the development of the 1700-mile Express/Platte crude oil pipeline system between Hardisty, Alberta and Wood River, Illinois. The Express pipeline transports 180,000 bpd Canadian crude oil to serve refineries along the Rockies and interconnects with Platte pipeline. The joint venture constructed 785 miles of new 24-inch pipeline across Alberta, Montana, and Wyoming. the Joint Venture then upgraded the Platte pipeline to deliver its maximum capacity of 120,000 bpd to connect with other pipelines and serve the refinery at Wood River, Illinois.

The Oleoducto Central S.A. (OCENSA) pipeline transports 480,000 bpd of crude oil from the Colombian oil fields in Cusiana and Cupiagua over 500 miles across the Andes mountains to the Caribbean port of Covenas, Colombia. TransCanada was a 50% owner of the operating company (CITCOL) and held 17.5% equity in the ownership consortium. Construction of the OCENSA pipeline commenced in late 1995 with operation start-up in 1997.

The Keystone Pipeline project is the 3,456-kilometre (2,148-mile) Pipeline that will transport crude oil from Hardisty, Alberta to U.S. Midwest markets at Wood River and Patoka, Illinois and to Cushing, Oklahoma. The Canadian portion of the project involves the conversion of approximately 864 kilometres (537 miles) of existing Canadian Mainline pipeline facilities from natural gas to crude oil transmission service and construction of approximately 373 kilometres (232 miles) of pipeline, pump stations and terminal facilities at Hardisty, Alberta. The U.S. portion of the project includes construction of approximately 2,219 kilometres (1,379 miles) of pipeline and pump stations.

The Keystone Pipeline will have an initial nominal capacity of 435,000 barrels per day in late 2009 and will be expanded to a nominal capacity of 590,000 barrels per day in late 2010. Construction has commenced on this project.

TransCanada Keystone Pipeline (Keystone) proposes to construct and operate a crude oil pipeline and related facilities from Hardisty, Alberta, Canada to the Port Arthur and east Houston areas of Texas in the United States (U.S.). The project, known as the Keystone XL Pipeline Project or Keystone XL, will have an initial capacity to deliver 700,000 barrels per day (bpd) of crude oil from an oil supply hub near Hardisty to existing terminals in Nederland near Port Arthur and the Houston Ship Channel in Houston, Texas. If market conditions warrant, additional pumping capacity could be added to expand Keystone XL to 900,000 bpd capacity.

In total, Keystone XL will consist of approximately 1702 miles of new 36-inch pipeline, including about 327 miles in Canada and 1375 miles within the U.S. It will also incorporate the 298 mile long, 36-inch Cushing extension pipeline ('Existing Segment' in Figure 1.1-1) in the US to complete a direct pipeline from Alberta to the US Gulf Coast. Appropriate regulatory authorities in Canada will conduct an independent environmental review process for the Canadian facilities.

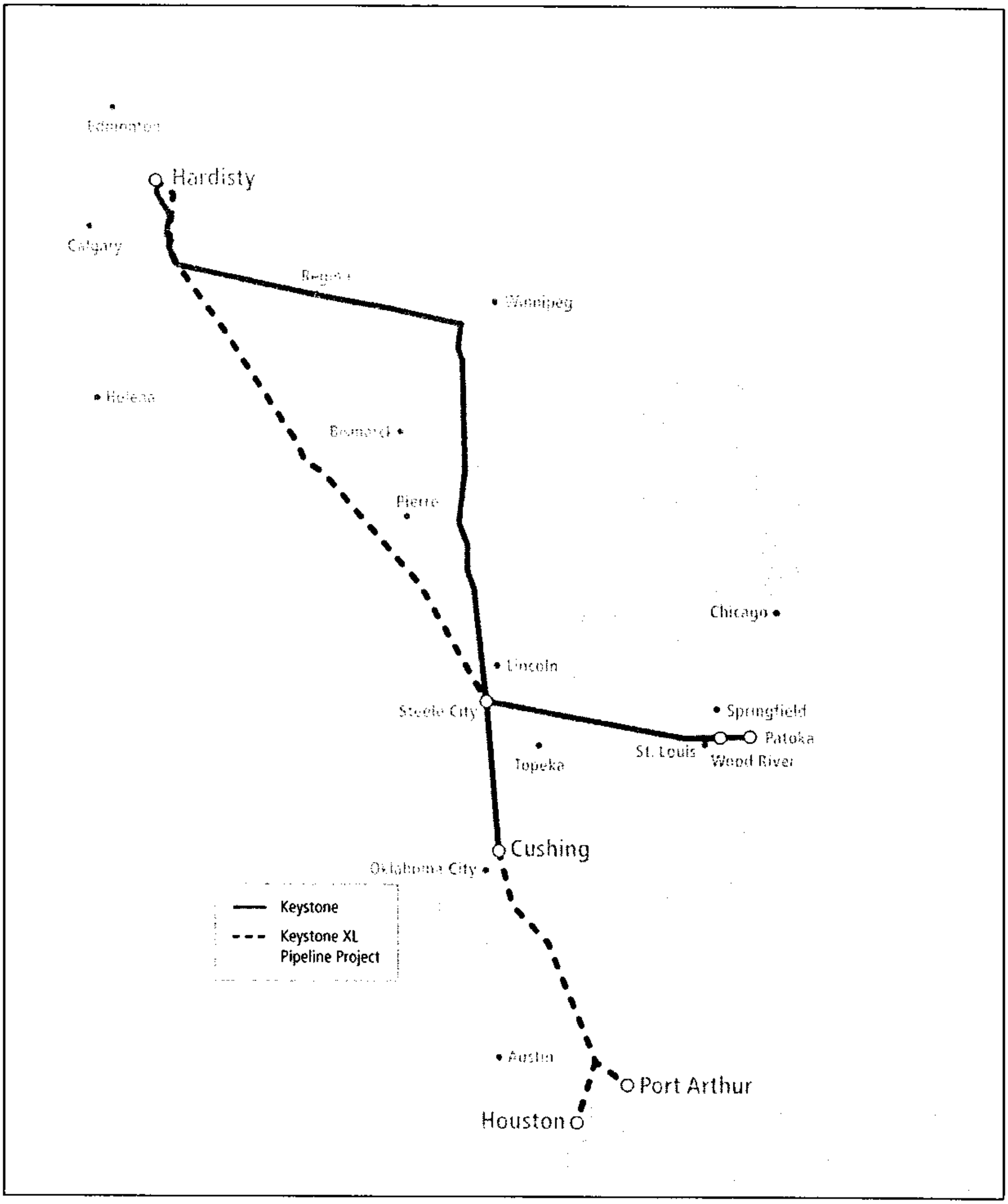


Figure 1.1-1 Proposed Keystone XL Pipeline Route

In the U.S., Keystone XL will construct and operate a new 1328-mile mainline pipeline (Keystone XL Mainline) and a 47-mile Houston Ship Channel Lateral (Houston Lateral), that will transport crude oil from the Canadian border to existing terminals at the US Gulf Coast in Texas. The new segments of Keystone XL will be constructed in two phases. Phase 2 consists of 850 miles of 36-inch pipeline between the Canadian border and Steele City, Nebraska. There, it will connect to the northern end of the 36-inch, 298 mile long, Cushing Extension pipeline being constructed as part of the Keystone project. Phase 1 of Keystone XL, would consist of 478 miles of 36-inch pipeline initiating at the southern end of the Cushing Extension at Cushing, Oklahoma and extend to an existing terminal at Nederland, Texas. An additional 47 mile 36-inch pipeline, the Houston Lateral, will be constructed from a point on the Keystone XL Mainline in Liberty County, Texas to an existing terminal junction point in the Houston Ship Channel area.

A total of 33 new pump stations will be constructed in the US, 10 on the Phase 1 Segment and 18 on the Phase 2 segment. Two new pump stations will be added to the Keystone Cushing Extension pipeline and additional pumping capacity will be added at the initial three pump stations of the Cushing Extension. Three tanks, with a planned capacity of 350,000 barrels each will be constructed at Steele City and will be used operationally for the management of batch movements.

Technology Development

TransCanada has an extensive track record of designing, developing, constructing, and operating major pipeline projects across North America and around the world. In collaboration with industry and regulators, TransCanada has been pursuing the challenge of reducing the high cost of pipeline construction though innovative technology and its implementation. In recent years, TransCanada has been pursuing a number of next generation pipeline technologies including: higher strength pipeline steels and components; mechanized welding; ultrasonic inspection; and advanced coating systems. TransCanada successfully implemented a number of these next generation technologies on its recent pipeline projects in Northern Alberta and Ontario, Canada.

The Peerless Lake project in northern Alberta consisted of 23.3 miles of NPS 24 Grade 483 (X70), 0.8 design factor pipe installed in the winter of 2004. In Peerless Phase I, 10.9 miles of NPS 24 was the first manual shielded metal arc welded project to be inspected completely by mechanized ultrasonic testing (UT) in North America. In addition, a field trial was conducted with next generation, phased array UT. In Peerless Phase II, TransCanada implemented mechanized tie-in welding as an alternative integrity validation process.

The Godin Lake project also in northern Alberta consisted of 1.24 miles of Grade 690 (X100), 0.8 design factor pipe, and 1 mile of Grade 830 (X120), 0.8 design factor pipe. Referred to as the Technology Loop, the project was installed parallel to the Peerless Lake Phase I project in the winter of 2004. The Technology Loop enabled implementation of the following technologies: winter construction of Grade 690 pipe; the first field trial of Grade 830 pipe; advanced mechanized welding using single tandem pulsed gas metal arc welding; high performance composite coating (HPCC); advanced field coatings for low temperature application; and 3 radius Grade 550 (X80) fittings.

In 2006, construction was completed on the Stittsville and Deux Rivieres looping projects in Ontario consisting of 23.5 miles of pipe using Grade 690 (X100), Grade 550 (X80) and Grade 483 (X70). Grade 690 (X100) pipe has been installed in Class 3 locations totalling 3.41 miles. The projects used an alternative integrity validation (AIV) process in place of hydrostatically testing the pipe during commissioning (AIV has been approved by the National Energy Board) which is one of the most significant technology implementation programs undertaken by

TransCanada in the last decade. The projects other technology initiatives consist of installation of high strength fittings, single tandem welding and mechanized tie ins and HPCC coating.

During the course of our fifty years of experience, we have become experts at managing and executing projects. Beginning in the 1950s, we pioneered the development of the first cross-Canada pipeline to transport western gas to eastern markets. Today, our 24,200 miles natural gas pipeline system ranks as one of the largest and most sophisticated in the world. We have also worked in joint venture teams to manage and execute numerous other projects, both in Canada and internationally.

TransCanada is a successful developer of mega-projects, world class in both scale and experience. This is well illustrated by our massive system expansion projects of the 1990s. Our project teams directly managed large-scale Canadian facility expansion programs with costs totaling approximately $11.2 billion. These capital programs included nearly 6,835 miles of large-diameter pipe (NPS 30 to 48), 2,361 megawatts of compression, and 376 custody transfer meter stations.

Operations Experience

Through almost 50 years of domestic experience and approximately 20 years of international experience, we have designed, constructed and operated pipelines in virtually every type of topography of the world such as the discontinuous permafrost of northern Alberta, the jungles of Malaysia, the prairies of southern Saskatchewan, the mountains of Argentina, Columbia and Chile, the sandstone rock of the Yucatan Peninsula in Mexico and the muskeg and bedrock of northern Ontario.

As a result of this widespread experience, knowledge gained from decades of operations, our North American pipeline network has developed into an extremely safe, reliable and cost-effective asset. We have attained this status by applying not only established industry knowledge but are own innovative processes and technology:

- We have implemented reliability-based methodologies into our design;
- We use risk models to validate design criteria and to set maintenance priorities;
- We utilize GIS technology to support our engineering and operations processes;
- We involve our corrosion experts from the first stages of design, not just during the operations phase of a pipeline;
- We have installed industry-leading high strength steels into our mainlines; and
- We have made mechanized welding the standard in large-diameter pipeline construction and we have developed and applied ultrasonic testing techniques that support the installation of high-grade steels.

TransCanada

Appendix B

Purpose and Need for the Project

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Purpose and Need for the Project

The purpose of the Keystone XL Project is to transport crude oil production from the Western Canadian Supply Basin (WCSB) to meet growing demand by refineries and markets in the United States (U.S.). The Keystone XL Project will transport crude oil from the oil supply hub near Hardisty, Alberta, Canada and deliver it to existing oil storage terminal facilities near Nederland and Houston, Texas. Construction of the Keystone XL Project will provide U.S. refineries and markets with access to a substantial and reliable supply of Canadian crude oil to meet increasing U.S. demand for petroleum products.

The need for the project is dictated by a number of factors including:

- Increasing WCSB crude oil supply;
- Increasing crude oil demand in the United States;
- Decreasing domestic crude supply in the United States;
- An opportunity to reduce U.S. dependence on foreign offshore oil supply through further supply diversification to stable, secure Canadian crude supplies; and
- Demonstrated shipper interest in the Keystone XL Project.

Established crude oil reserves in the WCSB are estimated at 179 billion barrels according to the Canadian Association of Petroleum Producers (CAPP, January, 2008). The primary source of WCSB crude oil supply -- over 97 percent -- is comprised of Canada's vast oil sands reserves located in northern Alberta. The Alberta Energy and Utilities Board (AEUB) estimates there are 175 billion barrels of established reserves out of 315 billion barrels of bitumen ultimately recoverable in Canada's oil sands. Alberta has the second largest crude oil reserves in the world, second only to Saudi Arabia.

As a result of growing production from the oil sands, crude oil supplies from the WCSB are expected to increase by about 1.6 million barrels per day (bpd) by 2017, from current production of about 2.4 million bpd[1].

According to the Energy Information Administration (EIA), U.S. demand for petroleum products has increased by over 11 percent or two million bpd over the past 10 years and is expected to increase further[2]. The EIA estimates that total U.S. petroleum consumption is projected to increase by approximately 1.0 million bpd over the next 10 years[3], representing average demand growth of about 100,000 bpd per year.

At the same time, domestic U.S. crude supplies continue to decline. For example, over the past 10 years, domestic crude production in the U.S. has declined at an average rate of about 135,000 bpd per year or two percent per year[2].

The U.S. historically has compensated for decreases in domestic production through increased imports from Canada and foreign offshore sources. Canada is currently the largest supplier of imported crude oil and refined products to the United States, supplying over 2.4 million bpd in 2007 and representing over 11 percent of total U.S. petroleum product consumption[2].

U.S. imports of foreign crude and refined products continue to increase as a result of decreasing domestic production and increasing demand. Crude and refined petroleum product imports into the U.S. have increased by over 3.3 million bpd over the past 10 years. In 2007,

[1] CAPP June 2008 Crude Oil Forecast Markets and Pipeline Expansions
[2] EIA, Annual Energy Review, 2007
[3] EIA, Annual Energy Outlook, 2008

the U.S. imported over 13.4 million bpd of crude oil and petroleum products or over 60 percent of total U.S. petroleum product consumption[2].

The Keystone XL Project's key delivery area, PADD III or the U.S. Gulf Coast, represents the largest and most complex refining district in the United States with 49 refineries comprising approximately eight million bpd of total refining capacity. Keystone XL would provide an opportunity for U.S. refiners in PADD III to diversify supply away from traditional offshore foreign crude supply and to obtain direct access to secure and growing Canadian crude supplies. Access to incremental Canadian crude supply would also provide an opportunity for the U.S. to supplement annual declines in domestic crude production and more significantly, decrease its dependence on offshore foreign crude supplies, namely from Mexico and Venezuela, the top two heavy crude oil importers into the U.S. Gulf Coast.

Shippers – producers, marketers or refiners, evaluate the merits of various pipeline proposals and ultimately decide which projects to support. Shippers have expressed material interest in Keystone XL and in securing additional crude oil pipeline capacity. Potential shippers have already committed to binding contracts totalling 300,000 bpd in support of Keystone XL. Keystone XL conducted a binding Open Season, which closed on September 4, 2008, to provide other shippers an opportunity to further participate in the Keystone XL Project. Keystone XL currently is evaluating the results of that Open Season.

The Keystone XL pipeline capacity commitments of 300,000 bpd in the form of binding contracts already received will enable Keystone XL to proceed with regulatory applications and, pending successful regulatory and environmental approvals, with construction of the pipeline. These binding commitments demonstrate a material endorsement of support for the Keystone

[2] EIA, Annual Energy Review, 2007

XL Project, its economics, proposed route, and target market, as well as the need for incremental pipeline capacity and access to Canadian crude supplies.

Appendix C

System Map

TransCanada

Appendix D

Summary of Keystone XL Pipeline Parameters

D.1 Comparison of Keystone Pipeline Special Permit to Keystone XL Parameters

Category	Keystone Pipeline Special Permit	Keystone XL Pipeline Parameters
Steel Properties	The skelp/plate must be micro alloyed, fine grain, fully killed steel with calcium treatment and continuous casting.	Same
Manufacturing Standards	The pipe must be manufactured according to American Petroleum Institute Specification 5L, Specification for Line Pipe (API 5L), product specification level 2 (PSL 2), supplementary requirements(SR) for maximum operating pressures and minimum operating temperatures. Pipe carbon equivalents must be at or below 0.23 percent based on the material chemistry parameter (Pcm) formula.	Same
Transportation Standards	The pipe delivered by rail car must be transported according to the API Recommended Practice 5LI, Recommended Practice or Railroad Transportation of Line Pipe (AP5L1).	Same
Fracture Control	API5L and other specifications and standards address the steel pipe toughness properties needed to resist crack initiation. Keystone must institute an overall fracture control plan addressing steel pipe properties necessary to resist crack initiation and propagation. The plan must include acceptable Charpy Impact and Drop Weight Tear Test values, which are measures of a steel pipeline's toughness and resistance to fracture. The fracture control plan, which must be submitted to PHMSA headquarters must be in accordance with API5L, Appendix F and must include the following tests: a) SR 5,A' - Fracture Toughness Testing for Shear Area: Test results must indicate at least 85 percent minimum average shear area for all X-70 heats and 80 percent minimum shear area for all X-80 heats with a minimum result of 80 percent shear area for any single test. The test results must also ensure a ductile fracture; b) SR 58 - Fracture Toughness Testing for Absorbed Energy; and c) SR 6 - Fracture Toughness Testing by Drop Weight Tear Test: Test results must be at least 80 percent of the average shear area for all heats with a minimum result of 60 percent of the shear area for any single test. The test results must also ensure a ductile fracture. The above	Same

Category	Keystone Pipeline Special Permit	Keystone XL Pipeline Parameters
	fracture initiation, propagation and arrest plan must account for the entire range of pipeline operating temperatures, pressures and product compositions planned for the pipeline diameter, grade and operating stress levels, including maximum pressures and minimum temperatures for start up and shut down conditions associated with the special permit area. If the fracture control plan for the pipe in the special permit area does not meet these specifications, Keystone must submit to PHMSA headquarters an alternative plan providing an acceptable method to resist crack initiation, crack propagation and to arrest ductile fractures in the special permit area	
Steel Plate Quality Control	The steel mill and/or pipe rolling mill must incorporate a comprehensive plate/coil mill and pipe mill inspection program to check for defects and inclusions that could affect the pipe quality. This program must include a plate or rolled pipe (body and all ends) ultrasonic testing (UT) inspection program per ASTM ,4'578 to check for imperfections such as laminations. An inspection protocol for centerline segregation evaluation using a test method referred to as slab macro-etching must be employed to check for inclusions that may form as the steel plate cools after it has been cast. A minimum of one macro-etch or a suitable alternative test must be performed from the first or second heat (manufacturing run) of each sequence (approximately four heats) and graded on the Mannesmann scale or equivalent. Test results with a Mannesmann scale rating of one or two out of a possible five scale are acceptable	Alternate wording is suggested to allow for flexibility with the steel supplies for the project. See discussion below.
Pipe Seam Quality Control	A quality assurance program must be instituted for pipe weld seams. The pipe weld seam tests must meet the minimum requirements for tensile strength in API5L for the appropriate pipe grade properties. A pipe weld seam hardness test using the Vickers hardness testing of a cross-section from the weld seam must be performed on one length of pipe from each heat. The maximum weld seam and heat affected zone hardness must be a maximum of 280 Vickers hardness(Hv10). The hardness tests must include a minimum of two readings for each heat affected zone, two readings in the weld metal and two readings in each section of pipe base metal for a total of 10 readings. The pipe	Alternate wording is suggested to allow for flexibility with the pipe mills for the project. See discussion below.

Category	Keystone Pipeline Special Permit	Keystone XL Pipeline Parameters
	weld seam must be 100 percent UT inspected after expansion and hydrostatic testing per APL 5L	
Monitoring Seam Fatigue for Transportation	Keystone must inspect the double submerged arc welded pipe seams of the delivered pipe using properly calibrated manual or automatic UT techniques. For each lay down urea, a minimum of one pipe section from the bottom layer of pipes of the first five rail car shipments from each pipe mill must be inspected. The entire longitudinal weld seam must be tested and the results appropriately documented. For helical seam submerged arc welded pipe, Keystone must test and document the weld seam in the area along the transportation bearing surfaces and all other exposed weld areas during the test. Each pipe section test record must be traceable to the pipe section tested. PHMSA headquarters must be notified of any flaws that exceeded specifications and needed to be removed. Keystone's findings will determine if PHMSA will require the testing program be expanded to include a larger sampling population for seam defects originating during pipeline transportation	Same
Puncture Resistance	Steel pipe must be puncture resistant to an excavator weighing up to 65 tons with a general purpose tooth size of 3.54 inches by 0.137 inches. Puncture resistance will be calculated based on industry established calculations such as the Pipeline Research Council International's Reliability Based Prevention of Mechanical Damage to Pipe line s calculation method.	Same. Validated. For an excavator weighing up to 65 tons (316 kN is the required puncture resistance) Appendix E provides the KXL resistance information.
Mill Hydrostatic Test	The pipe must be subjected to a mill hydrostatic test pressure of 95 percent of SMYS or greater for 10 seconds. Any mill hydrostatic test failures must be reported to PHMSA headquarters with the reason for the test failure.	Same
Field Coating	The application of a corrosion resistant coating to the steel pipe must be subject to a coating application quality control program. The program must address pipe surface cleanliness standards, blast cleaning, application temperature control, adhesion, cathodic disbondment, moisture permeation, bending, minimum coating thickness, coating imperfections and coating repair	Same

Category	Keystone Pipeline Special Permit	Keystone XL Pipeline Parameters
Coating for Trenchless Installation	Coatings used for directional bore, slick bore and other trenchless installation methods must resist abrasions and other damages that may occur due to rocks and other obstructions encountered in this installation technique	Same
Bend Quality	Certification records of factory induction bends and/or factory weld bends must be obtained and retained. All bends, flanges and fittings must have carbon equivalents (CE) equal to or below 0.42 or a pre-heat procedure must be applied prior to welding for CE above O.42	Same
Fittings	All pressure rated fittings and components (including flanges, valves, gaskets, pressure vessels and pumps) must be rated for a pressure rating commensurate with the MOP of the pipeline.	Same
Design Factor	Pipelines: Pipe installed under this special permit may use a 0.80 design factor. Pipe installed in pump stations, road crossings, railroad crossings, launcher/receiver fabrications, population HCAs and navigable waters must comply with the design factor in 49 CFR 195.106. If portions of the pipeline become population HCAs during the operational life of the pipeline, Keystone will apply to PHMSA headquarters for a special permit for the affected pipeline sections	Same
Temperature Control	The pipeline operating temperatures must be less than 150 degrees Fahrenheit	158°F
Overpressure Protection Control	Mainline pipeline overpressure protection must be limited to a maximum of 110 percent MOP consistent with 49 CFR 195.406(b). Construction Plans and Schedule: The construction plans, schedule and specifications must be submitted to the appropriate PHMSA regional office for review within two months of the anticipated construction start date. Subsequent plans and schedule revisions must also be submitted to the PHMSA regional office	Same
Welding Procedures	The appropriate PHMSA regional office must be notified within 14 days of the beginning of welding procedure qualification activities. Automated or manual welding procedure documentation must be submitted to the same PHMSA regional office for review. For X-80 pipe, Keystone must conform to revised procedures contained in the 20th edition of API Standard llO4, Welding of Pipelines and Related Facilities (API 1104), Appendix A, or by an alternative procedure	Will use 20th Edition

Category	Keystone Pipeline Special Permit	Keystone XL Pipeline Parameters
	approved by PHMSA headquarters	
Depth of Cover	The soil cover must be maintained at a minimum depth of 48 inches in all areas except consolidated rock. In areas where conditions prevent the maintenance of 42 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 placing warning tape and additional pipeline markers along the affected pipeline segment. In areas where the pipeline is susceptible to threats from chisel plowing or other activities, the top of the pipeline must be installed at least one foot below the deepest penetration above the pipeline. If routine patrols indicate the possible loss of cover over the pipeline, Keystone must perform a depth of cover study and replace cover as necessary to meet the minimum depth of cover requirements specified herein. If the replacement of cover is impractical or not possible, Keystone must install other protective measures including warning tape and closely spaced signs.	Same
Construction Quality	A construction quality assurance plan for quality standards and controls must be maintained throughout the construction phase with respect to: inspection, pipe hauling and stringing, field bending, welding, non-destructive examination (NDE) of girth welds, field joint coating, pipeline coating integrity tests, lowering of the pipeline in the ditch, padding materials to protect the pipeline, backfilling, alternating current (AC) interference mitigation and CP systems. All gith welds must be NDE by radiography or alternative means. The NDE examiner must have all current required certifications	Same
Interference Current Controls	Control of induced alternating current from parallel electric transmission lines and other interference issues that may affect the pipeline must be incorporated into the design of the pipeline and addressed during the construction phase. Issues identified and not originally addressed in the design phase must be brought to PHMSA headquarters' attention. An induced AC program to protect the pipeline from corrosion caused by stray currents must be in place and functioning within six months after placing the pipeline in service.	Same

Category	Keystone Pipeline Special Permit	Keystone XL Pipeline Parameters
Test Level	The pre-in service hydrostatic test must be to a pressure producing a hoop stress of 100 percent SMYS and l.25 X MOP in areas to operate to 80 percent SMYS. The hydrostatic test results from each test after completion of each pipeline must be submitted to PHMSA headquarters	Same
Assessment of Test Failures	Any pipe failure occurring during the pre-in service hydrostatic test must undergo a root cause failure analysis to include a metallurgical examination of the failed pipe. The results of this examination must preclude a systemic pipeline material issue and the results must be reported to PHMSA headquarters and the appropriate PHMSA regional office	Same
Supervisory Control and Data Acquisition (SCADA) System	A SCADA system to provide remote monitoring and control of the entire pipeline system must be employed	Same
SCADA System - General	a) Scan rate shall be fast enough to minimize over pressure conditions (overpressure control system), provide very responsive abnormal operation indications to controllers and detect small leaks within technology limitations; b) Must meet the requirements of regulations developed as a result of the findings of the National Transportation Safety Board, Supervisory Control and Data Acquisition (SCADA) in Liquid Pipelines, Safety Study,NTSB/SS-05102 specifically including: - Operator displays shall adhere to guidance provided in API Recommended Practice 1165,Recommended Practice for Pipeline SCADA Display (API RP 1165) - Operators must have a policy for the review/audit of alarms for false alarm reduction and near miss or lessons learned criteria - SCADA controller training shall include simulator for controller recognition of abnormal operating conditions, in particular leak events - See item2Tb below on fatigue management - Install computer-based leak detection system on all lines unless an engineering analysis determines that such a system is not necessary c) Develop and implement shift change procedures for controllers; d) Verify point-to-point display screens and SCADA system inputs before placing the line in service;	Same

Category	Keystone Pipeline Special Permit	Keystone XL Pipeline Parameters
	e) Implement individual controller log-in provisions; f) Establish and maintain a secure operating control room environment; g) Establish controls to functionally test the pipeline in an off-line mode prior to beginning the line fill and placing the pipeline in service; and h) Provide SCADA computer process load information tracking	
SCADA - Alarm Management: Alarm Management Policy and Procedure	a) Alarm priorities determination; b) Controllers' authority and responsibility; c) Clear alarm and event descriptors that are understood by controllers; d) Number of alarms; e) Potential systemic system issues; f) Unnecessary alarms; g) Controllers' performance regarding alarm or event response; h) Alarm indication of abnormal operating conditions (AOCs); D Combination AOCs or sequential alarms and events; and j) Workload concern	Same
SCADA - Leak Detection System (LDS)	a) Implementing applicable provisions in API Recommended Practice 1130, Computational Pipeline Monitoring for Liquid Pipelines (API RP 1130), as appropriate; b) Addressing the following leak detection system testing and validation issues: - Routine testing to ensure degradation has not affected functionality - Validation of the ability of the LDS to detect small leaks and modification of the LDS as necessary to enhance its accuracy to detect small leaks - Conduct a risk analysis of pipeline segments to identify additional actions that would enhance public safety or environmental protection c) Developing data validation plan (ensure input data to SCADA is valid); d) Defining leak detection criteria in the following areas: - Minimum size of leak to be detected regardless of pipeline operating conditions including slack and transient conditions - Leak location accuracy for various pipeline conditions - Response time for various pipeline conditions e) Providing redundancy plans for hardware and software and a periodic test requirement for	Same

Category	Keystone Pipeline Special Permit	Keystone XL Pipeline Parameters
	equipment to be used live (also applies to SCADA equipment).	
SCADA - Pipeline Model and Simulator	The Thermal-Hydraulic Pipeline Model/ Simulator including pressure control system shall include a Model Validation/Verification plan	Same
SCADA - Training	The training and qualification plan (including simulator training) for controllers shall: a) Emphasize procedures for detecting and mitigating leaks; b) Include a fatigue management plan and implementation of a shift rotation schedule that minimizes possible fatigue concerns; c) Define controller maximum hours of service limitations; d) Meet the requirements of regulations developed as a result of the guidance provided in the American Society of Mechanical Engineers Standard 831Q, Pipeline Personnel Qualification Standard (ASME B31Q), September 2006 for developing qualification program plans; e) Include and implement a full training simulator capable of replaying near miss or lesson learned scenarios for training purposes; f) Implement tabletop exercises periodically that allow controllers to provide feedback to the exercises, participate in exercise scenario development and actively participate in the exercise; g) Include field visits for controllers accompanied by field personnel who will respond to call-outs for that specific facility location; h) Provide facility specifics in regard to the position certain equipment devices will default to upon power loss; i) Include color blind and hearing provisions and testing if these are required to identify alarm priority or equipment status; j) Training components for task specific abnormal operating conditions and generic abnormal operating conditions; k) If controllers are required to respond to "800" calls, include a training program conveying proper procedures for responding to emergency calls, notification of other pipeline operators in the area when affecting a common pipeline corridor and education on the types of communications supplied to emergency responders and the public using API	Same

Category	Keystone Pipeline Special Permit	Keystone XL Pipeline Parameters
	Recommended Practice 7762, Public Awareness Programs for Pipeline Operators (APr RP 1162); l) Implement on-the-job training component intervals established by performance review to include thorough documentation of all items covered during oral communication instruction; and m) Implement a substantiated qualification program for re-qualification intervals addressing program requirements for circumstances resulting in disqualification, procedure documentation for maximum controller absences before a period of review, shadowing, retraining, and addressing interim performance verification measures between re-qualification intervals.	
SCADA - Calibration and Maintenance	The calibration and maintenance plan for the instrumentation and SCADA system shall be developed using guidance provided in API 1130. Instrumentation repairs shall be tracked and documentation provided regarding prioritization of these repairs. Controller log notes shall periodically be reviewed for concerns regarding mechanical problems. This information will be tracked and prioritized.	Same
SCADA - Leak Detection Manual	The Leak Detection Manual shall be prepared using guidance provided in Canadian Standards Association, Oil and Gas Pipeline Systems, CSA 2662-03, Annex E, Section 8.5.2, Leak Detection Manual	Same
Mainline Valve Control	Mainline valves located on either side of a pipeline segment containing an HCA where personnel response time to the valve exceeds one hour must be remotely controlled by the SCADA system. The SCADA system must be capable of opening and closing the valve and monitoring the valve position, upstream pressure and downstream pressure.	Same
Pipeline Inspection	The pipeline must be capable of passing in line inspection (ILI) tools. All headers and other segments covered under this special permit that do not allow the passage of an ILI device must have a corrosion mitigation plan	Same
Internal Corrosion	Keystone shall limit sediment and water (S&W) to 0.5 percent by volume and report S&W testing results to PHMSA in the 180-day and annual reports. Keystone shall also report upset conditions causing S&W level excursions above the limit. This report shall also contain remedial	Same

Category	Keystone Pipeline Special Permit	Keystone XL Pipeline Parameters
	measures Keystone has taken to prevent a recurrence of excursions above the S&W limits. Keystone must run cleaning pigs twice in the first full year of operation and as necessary in succeeding years based on the analysis of oil constituents, weight loss coupons located in areas with the greatest internal corrosion threat and other internal corrosion threats. Keystone will send their analyses and further actions, if any, to PHMSA.	
Cathodic Protection	The initial CP system must be operational within six months of placing a pipeline segment in service	Same
Interference Current Surveys	Interference surveys must be performed within six months of placing the pipeline in service to ensure compliance with applicable NACE International Standard Recommended Practices0 169 and0177 (NACE RP 0169 and NACE RP 0177) for interference current levels. If interference currents are found, Keystone will determine if there have been any adverse affects to the pipeline and mitigate the affects as necessary. Keystone will report the results of any negative finding and the associated mitigative efforts to the appropriate PHMSA regional office	Same
Corrosion Surveys	Corrosion surveys of the affected pipeline must be completed within six months of placing the respective CP system(s) in operation to ensure adequate external corrosion protection per NACE RP 0169. The survey will also address the proper number and location of CP test stations as well as AC interference mitigation and AC grounding programs per NACE RP 0177. At least one CP test station must be located within each HCA with a maximum spacing between test stations of one-half mile within the HCA. If placement of a test station within an HCA is impractical, the test station must be placed at the nearest practical location. If any annual test station reading fails to meet 49 CFR 195, Subpart H requirements, remedial actions must occur within six months. Remedial actions must include a close interval survey on each side of the affected test station and all modifications to the CP system necessary to ensure adequate external corrosion control	Same
Initial Close Interval Survey (CIS) - Initial	A CIS must be performed on the pipeline within two years of the pipeline in-service date. The CIS results must be integrated with the baseline	Same

Category	Keystone Pipeline Special Permit	Keystone XL Pipeline Parameters
	ILI to determine whether further action is needed	
Pipeline Markers	Keystone must employ line-of-sight markings on the pipeline in the special permit area except in agricultural areas or large water crossings such as lakes where line of sight markers are impractical. The marking of pipelines is also subject to Federal Energy Regulatory Commission orders or environmental permits and local restrictions. Additional markers must be placed along the pipeline in areas where the pipeline is buried less than 42 inches	Same
Monitoring of Ground Movement	An effective monitoring/mitigation plan must be in place to monitor for and mitigate issues of unstable soil and ground movement	Same
Initial In-Line Inspection (ILI)	Keystone must perform a baseline ILI in association with the construction of the pipeline using a high-resolution Magnetic Flux Leakage (MFL) tool to be completed within three years of placing a pipeline segment in service. The high resolution MFL tool must be capable of gouge detection. Keystone must perform a baseline geometry tool run after completion of the hydrostatic strength test and backfill of the pipeline, but no later than six months after placing the pipeline in service under a special permit. The ILI data summary sheets and planned digs with associated ILI tool readings will be sent to the PHMSA regional office. The PHMSA regional office will be given at least 14 days notice before confirmation digs are executed on site. The dimensional data and other characteristics extracted from these digs will be shared with the PHMSA regional office. Keystone will also compare dimensional data and other characteristics extracted from the digs and compare them with ILI tool data. If there are large variations between dig data and ILI tool data, Keystone will submit PHMSA a plan on further actions, inclusive of more digs, to calibrate their analysis and remediation process.	Same
Future ILI	Future ILI inspection must be performed on the entire pipeline subject to the special permit, on a frequency consistent with 49 CFR 195.452Q)(3), assessment intervals, or on a frequency determined by fatigue studies based on actual operating conditions, inclusive of flaw and corrosion growth models	Same
Verification of Reassessment interval	Keystone must submit a new fatigue analysis validate the pipeline reassessment interval annually for the first five years after placing the	Same

Category	Keystone Pipeline Special Permit	Keystone XL Pipeline Parameters
	pipeline subject to this special permit in service. The analysis must be performed on the segment experiencing the most severe historical pressure cycling conditions using actual pipeline pressure data.	
Fatigue	Two years after the pipeline in-service date, Keystone will use all data gathered on pipeline section experiencing the most pressure cycles to determine effect on flaw growth that passed manufacturing standards and installation specifications. This study will be performed by an independent party agreed to by Keystone and PHMSA headquarters. Furthermore, this study will be shared with PHMSA headquarters as soon as practical after its completion, preferably before baseline assessment begins. These findings will determine if an ultrasonic crack detection tool must be launched in that pipeline section to confirm crack growth with Keystone's crack growth predictive models.	Same
Direct Assessment Plan	Headers, mainline valve bypasses and other sections covered by this special permit that cannot accommodate ILI tools must be part of a Direct Assessment (DA) plan or other acceptable integrity monitoring method using External and Internal Corrosion Direct Assessment criteria (ECDA/ICDA).	Same
Damage Prevention	The Common Ground Alliance (CGA) damage prevention best practices applicable to pipelines must be incorporated into the Keystone's damage prevention program.	Same
Anomaly Evaluation and Repair	Anomaly evaluations and repairs in the special permit area must be performed based upon the following: a) Immediate Repair Conditions: Follow l95.452(h)(4)(i) except designate the calculated remaining strength failure pressure ratio (FPR) = < 1.16; b) 60-Day Conditions: No changes to 195.452(hXaXii); c) 180-DayConditions: Follow l95.452(H)(4xiii) with exceptions for the following conditions which must be scheduled for repair within 180 days: - Calculated FPR = < l.32 - Areas of general corrosion with predicted metal loss greater than 40 percent - Predicted metal loss is greater than 40 percent of nominal wall that is located at a crossing of another pipeline - Gouge or groove greater than 8 percent of	Same

Category	Keystone Pipeline Special Permit	Keystone XL Pipeline Parameters
	nominal wall d) Each anomaly not repaired under the immediate repair requirements must have a corrosion growth rate and ILI tool tolerance assigned per the Integrity Management Program (IMP) to determine the maximum re-inspection interval. e) Anomaly Assessment Methods: Keystone must confirm the remaining strength (RSTRENG) effective area,R -STRENG - 0.85dL and ASME B31G assessment methods are valid for the pipe diameter, wall thickness, grade, operating pressure, operating stress level and operating temperature. f) Keystone must also use the most conservative method until confirmation of the proper method is made to PHMSA headquarters. Flow Stress: Remaining strength calculations for X-80 pipe must use a flow stress equal to the average of the ultimate (tensile) strength and the SMYS. g) Dents: For initial construction and the initial geometry tool run, any dent with a depth greater than2 percent of the nominal pipe diameter must be removed unless the dent is repaired by a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe. For the purposes of this condition, a "dent" is a depression that produces a gross disturbance in the curvature of the pipe wall without reducing the pipe wall thickness. The depth of the dent is measured as the gap between the lowest point of the dent and the prolongation of the original contour of the pipe.	
Reporting - Immediate	Keystone must notify the appropriate PHMSA regional office within 24 hours of any non-reportable leaks originating in the pipe body in the special permit area	Same
Reporting – 180 Days	Reporting - 180 Day: Within 180 days of the pipeline in-service date under a special permit, Keystone shall report on its compliance with special permit conditions to PHMSA Headquarters and the appropriate regional office. The report must also include pipeline operating pressure data, including all pressures and pressure cycles versus time. The data format must include both raw data in a tabular format and a graphical format. Any alternative formats must be approved by PHMSA	Same

Category	Keystone Pipeline Special Permit	Keystone XL Pipeline Parameters
	headquarters.	
Annual Reporting	Following approval of the special permit, Keystone must annually report the following: a) The results of any ILI or direct assessment results performed within the special permit area during the previous year; b) The results of all internal corrosion management programs including the results of: - S&W analyses - Report of processing plant upset conditions where elevated levels of S&W are introduced into the pipeline - Corrosion inhibitor and biocide injection - internal cleaning program - Wall loss coupon tests c) Any new integrity threats identified within the special permit area during the previous year; d) Any encroachment in the special permit area, including the number of new residences or public gathering areas; e) Any HCA changes in the special permit area during the previous year; f) Any reportable incidents associated with the special permit area that gccurred during the previous year; g) Any leaks on the pipeline in the special permit area that occurred during the previous year; h) A list of all repairs on the pipeline in the special permit area during the previous year; i) On-going damage prevention initiatives on the pipeline in the special permit area and a discussion of their success or failure; j) Any changes in procedures used to assess and/or monitor the pipeline operating under this special permit; k) Any company mergers, acquisitions, transfers of assets, or other events affecting the regulatory responsibility of the company operating the pipeline to which this special permit applies; and l) A report of pipeline operating pressure data to include all pressures and pressure cycles versus time. The data format must include both raw data in a tabular format and a graphical format. Any alternative formats must be approved by PHMSA headquarters	Same

Discussion

Current Keystone Oil Pipeline Special Permit PHMSA 2006-26617 Condition #5

Steel Plate Quality Control:

The steel mill and/or pipe rolling mill must incorporate a comprehensive plate/coil mill and pipe mill inspection program to check for defects and inclusions that could affect the pipe quality. This program must include a plate or rolled pipe (body and all ends) ultrasonic testing (UT) inspection program per ASTM ,4'578 to check for imperfections such as laminations. An inspection protocol for centerline segregation evaluation using a test method referred to as slab macro-etching must be employed to check for inclusions that may form as the steel plate cools after it has been cast. A minimum of one macro-etch or a suitable alternative test must be performed from the first or second heat (manufacturing run) of each sequence (approximately four heats) and graded on the Mannesmann scale or equivalent. Test results with a Mannesmann scale rating of one or two out of a possible five scale are acceptable

Suggested Alternate Wording:

Steel Plate Quality Control:

The steel mill and/or pipe rolling mill must incorporate a comprehensive plate/coil mill and pipe mill inspection program to check for defects and inclusions that could affect the pipe quality. This program must include a plate or rolled pipe (body and all ends) ultrasonic testing (UT) inspection program per ASTM ,4'578 to check for imperfections such as laminations. An inspection protocol for centerline segregation evaluation using a test method referred to as slab macro-etching must be employed to check for inclusions that may form as the steel plate cools after it has been cast. A minimum of one macro-etch or a suitable alternative test must be performed from the first or second heat

~~(manufacturing run)~~ of each ***casting*** sequence ~~(approximately four heats)~~ and graded on the Mannesmann scale or equivalent. Test results with a Mannesmann scale rating of one or two out of a possible five scale are acceptable

The alternate wording allows for the steel supplier's casting sequence to determine the frequency. In a longer casting sequence test would be performed at the start and end to ensure confidence in quality for the heats in between. As part of the KXL application PHMSA technical review process, the recent submissions from industry groups could be used to refine this condition.

<u>Current Keystone Oil Pipeline Special Permit PHMSA 2006-26617 Condition #6</u>

Pipe Seam Quality Control:

A quality assurance program must be instituted for pipe weld seams. The pipe weld seam tests must meet the minimum requirements for tensile strength in API5L for the appropriate pipe grade properties. A pipe weld seam hardness test using the Vickers hardness testing of a cross-section from the weld seam must be performed on one length of pipe from each heat. The maximum weld seam and heat affected zone hardness must be a maximum of 280 Vickers hardness(Hv10). The hardness tests must include a minimum of two readings for each heat affected zone, two readings in the weld metal and two readings in each section of pipe base metal for a total of 10 readings. The pipe weld seam must be 100 percent UT inspected after expansion and hydrostatic testing per APL 5L

<u>Suggested Alternate Wording:</u>

Pipe Seam Quality Control:

A quality assurance program must be instituted for pipe weld seams. The pipe weld seam tests must meet the minimum requirements for tensile strength in API5L for the appropriate pipe grade properties. ***Manufacturing procedures must require qualification of the welding procedures to ASME Section IX to ensure seam quality.*** A pipe weld seam hardness test using the Vickers hardness testing of a cross-section from the weld seam must be performed on one length of pipe from each heat. The maximum weld seam and heat affected zone hardness must be a maximum of ~~280~~ ***350*** Vickers hardness(Hv~~10~~ ***1000g***). The hardness tests must include a minimum of two readings for each heat affected zone, two readings in the weld metal and two readings in each section of pipe base metal for a total of 10 readings. The pipe weld seam must be 100 percent UT inspected after expansion and hydrostatic

The alternate wording would accommodate the use of high strength pipe such as X80, presently the current conditions limit the possibility of the high strength steels offered by approved TransCanada suppliers. TransCanada would like to explore revisions to this condition during PHMSA's technical review process.

Appendix D

Summary of Keystone XL Pipeline Parameters

D.1 Comparison of Keystone Pipeline Special Permit to Keystone XL Parameters

Category	Keystone Pipeline Special Permit	Keystone XL Pipeline Parameters
Steel Properties	The skelp/plate must be micro alloyed, fine grain, fully killed steel with calcium treatment and continuous casting.	Same
Manufacturing Standards	The pipe must be manufactured according to American Petroleum Institute Specification 5L, Specification for Line Pipe (API 5L), product specification level 2 (PSL 2), supplementary requirements(SR) for maximum operating pressures and minimum operating temperatures. Pipe carbon equivalents must be at or below 0.23 percent based on the material chemistry parameter (Pcm) formula.	Same
Transportation Standards	The pipe delivered by rail car must be transported according to the API Recommended Practice 5LI, Recommended Practice or Railroad Transportation of Line Pipe (AP5L1).	Same
Fracture Control	API5L and other specifications and standards address the steel pipe toughness properties needed to resist crack initiation. Keystone must institute an overall fracture control plan addressing steel pipe properties necessary to resist crack initiation and propagation. The plan must include acceptable Charpy Impact and Drop Weight Tear Test values, which are measures of a steel pipeline's toughness and resistance to fracture. The fracture control plan, which must be submitted to PHMSA headquarters must be in accordance with API5L, Appendix F and must include the following tests: a) SR 5,A' - Fracture Toughness Testing for Shear Area: Test results must indicate at least 85 percent minimum average shear area for all X-70 heats and 80 percent minimum shear area for all X-80 heats with a minimum result of 80 percent shear area for any single test. The test results must also ensure a ductile fracture; b) SR 58 - Fracture Toughness Testing for Absorbed Energy; and c) SR 6 - Fracture Toughness Testing by Drop Weight Tear Test: Test results must be at least 80 percent of the average shear area for all heats with a minimum result of 60 percent of the shear area for any single test. The test results must also ensure a ductile fracture. The above	Same

Category	Keystone Pipeline Special Permit	Keystone XL Pipeline Parameters
	fracture initiation, propagation and arrest plan must account for the entire range of pipeline operating temperatures, pressures and product compositions planned for the pipeline diameter, grade and operating stress levels, including maximum pressures and minimum temperatures for start up and shut down conditions associated with the special permit area. If the fracture control plan for the pipe in the special permit area does not meet these specifications, Keystone must submit to PHMSA headquarters an alternative plan providing an acceptable method to resist crack initiation, crack propagation and to arrest ductile fractures in the special permit area	
Steel Plate Quality Control	The steel mill and/or pipe rolling mill must incorporate a comprehensive plate/coil mill and pipe mill inspection program to check for defects and inclusions that could affect the pipe quality. This program must include a plate or rolled pipe (body and all ends) ultrasonic testing (UT) inspection program per ASTM ,4'578 to check for imperfections such as laminations. An inspection protocol for centerline segregation evaluation using a test method referred to as slab macro-etching must be employed to check for inclusions that may form as the steel plate cools after it has been cast. A minimum of one macro-etch or a suitable alternative test must be performed from the first or second heat (manufacturing run) of each sequence (approximately four heats) and graded on the Mannesmann scale or equivalent. Test results with a Mannesmann scale rating of one or two out of a possible five scale are acceptable	Alternate wording is suggested to allow for flexibility with the steel supplies for the project. See discussion below.
Pipe Seam Quality Control	A quality assurance program must be instituted for pipe weld seams. The pipe weld seam tests must meet the minimum requirements for tensile strength in API5L for the appropriate pipe grade properties. A pipe weld seam hardness test using the Vickers hardness testing of a cross-section from the weld seam must be performed on one length of pipe from each heat. The maximum weld seam and heat affected zone hardness must be a maximum of 280 Vickers hardness(Hv10). The hardness tests must include a minimum of two readings for each heat affected zone, two readings in the weld metal and two readings in each section of pipe base metal for a total of 10 readings. The pipe	Alternate wording is suggested to allow for flexibility with the pipe mills for the project. See discussion below.

Category	Keystone Pipeline Special Permit	Keystone XL Pipeline Parameters
	weld seam must be 100 percent UT inspected after expansion and hydrostatic testing per APL 5L	
Monitoring Seam Fatigue for Transportation	Keystone must inspect the double submerged arc welded pipe seams of the delivered pipe using properly calibrated manual or automatic UT techniques. For each lay down urea, a minimum of one pipe section from the bottom layer of pipes of the first five rail car shipments from each pipe mill must be inspected. The entire longitudinal weld seam must be tested and the results appropriately documented. For helical seam submerged arc welded pipe, Keystone must test and document the weld seam in the area along the transportation bearing surfaces and all other exposed weld areas during the test. Each pipe section test record must be traceable to the pipe section tested. PHMSA headquarters must be notified of any flaws that exceeded specifications and needed to be removed. Keystone's findings will determine if PHMSA will require the testing program be expanded to include a larger sampling population for seam defects originating during pipeline transportation	Same
Puncture Resistance	Steel pipe must be puncture resistant to an excavator weighing up to 65 tons with a general purpose tooth size of 3.54 inches by 0.137 inches. Puncture resistance will be calculated based on industry established calculations such as the Pipeline Research Council International's Reliability Based Prevention of Mechanical Damage to Pipe line s calculation method.	Same. Validated. For an excavator weighing up to 65 tons (316 kN is the required puncture resistance) Appendix E provides the KXL resistance information.
Mill Hydrostatic Test	The pipe must be subjected to a mill hydrostatic test pressure of 95 percent of SMYS or greater for 10 seconds. Any mill hydrostatic test failures must be reported to PHMSA headquarters with the reason for the test failure.	Same
Field Coating	The application of a corrosion resistant coating to the steel pipe must be subject to a coating application quality control program. The program must address pipe surface cleanliness standards, blast cleaning, application temperature control, adhesion, cathodic disbondment, moisture permeation, bending, minimum coating thickness, coating imperfections and coating repair	Same

Category	Keystone Pipeline Special Permit	Keystone XL Pipeline Parameters
Coating for Trenchless Installation	Coatings used for directional bore, slick bore and other trenchless installation methods must resist abrasions and other damages that may occur due to rocks and other obstructions encountered in this installation technique	Same
Bend Quality	Certification records of factory induction bends and/or factory weld bends must be obtained and retained. All bends, flanges and fittings must have carbon equivalents (CE) equal to or below 0.42 or a pre-heat procedure must be applied prior to welding for CE above O.42	Same
Fittings	All pressure rated fittings and components (including flanges, valves, gaskets, pressure vessels and pumps) must be rated for a pressure rating commensurate with the MOP of the pipeline.	Same
Design Factor	Pipelines: Pipe installed under this special permit may use a 0.80 design factor. Pipe installed in pump stations, road crossings, railroad crossings, launcher/receiver fabrications, population HCAs and navigable waters must comply with the design factor in 49 CFR 195.106. If portions of the pipeline become population HCAs during the operational life of the pipeline, Keystone will apply to PHMSA headquarters for a special permit for the affected pipeline sections	Same
Temperature Control	The pipeline operating temperatures must be less than 150 degrees Fahrenheit	158°F
Overpressure Protection Control	Mainline pipeline overpressure protection must be limited to a maximum of 110 percent MOP consistent with 49 CFR 195.406(b). Construction Plans and Schedule: The construction plans, schedule and specifications must be submitted to the appropriate PHMSA regional office for review within two months of the anticipated construction start date. Subsequent plans and schedule revisions must also be submitted to the PHMSA regional office	Same
Welding Procedures	The appropriate PHMSA regional office must be notified within 14 days of the beginning of welding procedure qualification activities. Automated or manual welding procedure documentation must be submitted to the same PHMSA regional office for review. For X-80 pipe, Keystone must conform to revised procedures contained in the 20th edition of API Standard llO4, Welding of Pipelines and Related Facilities (API 1104), Appendix A, or by an alternative procedure	Will use 20th Edition

Category	Keystone Pipeline Special Permit	Keystone XL Pipeline Parameters
	approved by PHMSA headquarters	
Depth of Cover	The soil cover must be maintained at a minimum depth of 48 inches in all areas except consolidated rock. In areas where conditions prevent the maintenance of 42 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 placing warning tape and additional pipeline markers along the affected pipeline segment. In areas where the pipeline is susceptible to threats from chisel plowing or other activities, the top of the pipeline must be installed at least one foot below the deepest penetration above the pipeline. If routine patrols indicate the possible loss of cover over the pipeline, Keystone must perform a depth of cover study and replace cover as necessary to meet the minimum depth of cover requirements specified herein. If the replacement of cover is impractical or not possible, Keystone must install other protective measures including warning tape and closely spaced signs.	Same
Construction Quality	A construction quality assurance plan for quality standards and controls must be maintained throughout the construction phase with respect to: inspection, pipe hauling and stringing, field bending, welding, non-destructive examination (NDE) of girth welds, field joint coating, pipeline coating integrity tests, lowering of the pipeline in the ditch, padding materials to protect the pipeline, backfilling, alternating current (AC) interference mitigation and CP systems. All gith welds must be NDE by radiography or alternative means. The NDE examiner must have all current required certifications	Same
Interference Current Controls	Control of induced alternating current from parallel electric transmission lines and other interference issues that may affect the pipeline must be incorporated into the design of the pipeline and addressed during the construction phase. Issues identified and not originally addressed in the design phase must be brought to PHMSA headquarters' attention. An induced AC program to protect the pipeline from corrosion caused by stray currents must be in place and functioning within six months after placing the pipeline in service.	Same

Category	Keystone Pipeline Special Permit	Keystone XL Pipeline Parameters
Test Level	The pre-in service hydrostatic test must be to a pressure producing a hoop stress of 100 percent SMYS and l.25 X MOP in areas to operate to 80 percent SMYS. The hydrostatic test results from each test after completion of each pipeline must be submitted to PHMSA headquarters	Same
Assessment of Test Failures	Any pipe failure occurring during the pre-in service hydrostatic test must undergo a root cause failure analysis to include a metallurgical examination of the failed pipe. The results of this examination must preclude a systemic pipeline material issue and the results must be reported to PHMSA headquarters and the appropriate PHMSA regional office	Same
Supervisory Control and Data Acquisition (SCADA) System	A SCADA system to provide remote monitoring and control of the entire pipeline system must be employed	Same
SCADA System - General	a) Scan rate shall be fast enough to minimize over pressure conditions (overpressure control system), provide very responsive abnormal operation indications to controllers and detect small leaks within technology limitations; b) Must meet the requirements of regulations developed as a result of the findings of the National Transportation Safety Board, Supervisory Control and Data Acquisition (SCADA) in Liquid Pipelines, Safety Study,NTSB/SS-05102 specifically including: - Operator displays shall adhere to guidance provided in API Recommended Practice 1165,Recommended Practice for Pipeline SCADA Display (API RP 1165) - Operators must have a policy for the review/audit of alarms for false alarm reduction and near miss or lessons learned criteria - SCADA controller training shall include simulator for controller recognition of abnormal operating conditions, in particular leak events - See item2Tb below on fatigue management - Install computer-based leak detection system on all lines unless an engineering analysis determines that such a system is not necessary c) Develop and implement shift change procedures for controllers; d) Verify point-to-point display screens and SCADA system inputs before placing the line in service;	Same

Category	Keystone Pipeline Special Permit	Keystone XL Pipeline Parameters
	e) Implement individual controller log-in provisions; f) Establish and maintain a secure operating control room environment; g) Establish controls to functionally test the pipeline in an off-line mode prior to beginning the line fill and placing the pipeline in service; and h) Provide SCADA computer process load information tracking	
SCADA - Alarm Management: Alarm Management Policy and Procedure	a) Alarm priorities determination; b) Controllers' authority and responsibility; c) Clear alarm and event descriptors that are understood by controllers; d) Number of alarms; e) Potential systemic system issues; f) Unnecessary alarms; g) Controllers' performance regarding alarm or event response; h) Alarm indication of abnormal operating conditions (AOCs); D Combination AOCs or sequential alarms and events; and j) Workload concern	Same
SCADA - Leak Detection System (LDS)	a) Implementing applicable provisions in API Recommended Practice 1130, Computational Pipeline Monitoring for Liquid Pipelines (API RP 1130), as appropriate; b) Addressing the following leak detection system testing and validation issues: - Routine testing to ensure degradation has not affected functionality - Validation of the ability of the LDS to detect small leaks and modification of the LDS as necessary to enhance its accuracy to detect small leaks - Conduct a risk analysis of pipeline segments to identify additional actions that would enhance public safety or environmental protection c) Developing data validation plan (ensure input data to SCADA is valid); d) Defining leak detection criteria in the following areas: - Minimum size of leak to be detected regardless of pipeline operating conditions including slack and transient conditions - Leak location accuracy for various pipeline conditions - Response time for various pipeline conditions e) Providing redundancy plans for hardware and software and a periodic test requirement for	Same

Category	Keystone Pipeline Special Permit	Keystone XL Pipeline Parameters
	equipment to be used live (also applies to SCADA equipment).	
SCADA - Pipeline Model and Simulator	The Thermal-Hydraulic Pipeline Model/ Simulator including pressure control system shall include a Model Validation/Verification plan	Same
SCADA - Training	The training and qualification plan (including simulator training) for controllers shall: a) Emphasize procedures for detecting and mitigating leaks; b) Include a fatigue management plan and implementation of a shift rotation schedule that minimizes possible fatigue concerns; c) Define controller maximum hours of service limitations; d) Meet the requirements of regulations developed as a result of the guidance provided in the American Society of Mechanical Engineers Standard 831Q, Pipeline Personnel Qualification Standard (ASME B31Q), September 2006 for developing qualification program plans; e) Include and implement a full training simulator capable of replaying near miss or lesson learned scenarios for training purposes; f) Implement tabletop exercises periodically that allow controllers to provide feedback to the exercises, participate in exercise scenario development and actively participate in the exercise; g) Include field visits for controllers accompanied by field personnel who will respond to call-outs for that specific facility location; h) Provide facility specifics in regard to the position certain equipment devices will default to upon power loss; i) Include color blind and hearing provisions and testing if these are required to identify alarm priority or equipment status; j) Training components for task specific abnormal operating conditions and generic abnormal operating conditions; k) If controllers are required to respond to "800" calls, include a training program conveying proper procedures for responding to emergency calls, notification of other pipeline operators in the area when affecting a common pipeline corridor and education on the types of communications supplied to emergency responders and the public using API	Same

Category	Keystone Pipeline Special Permit	Keystone XL Pipeline Parameters
	Recommended Practice 7762, Public Awareness Programs for Pipeline Operators (APr RP 1162); l) Implement on-the-job training component intervals established by performance review to include thorough documentation of all items covered during oral communication instruction; and m) Implement a substantiated qualification program for re-qualification intervals addressing program requirements for circumstances resulting in disqualification, procedure documentation for maximum controller absences before a period of review; shadowing, retraining, and addressing interim performance verification measures between re-qualification intervals.	
SCADA - Calibration and Maintenance	The calibration and maintenance plan for the instrumentation and SCADA system shall be developed using guidance provided in API 1130. Instrumentation repairs shall be tracked and documentation provided regarding prioritization of these repairs. Controller log notes shall periodically be reviewed for concerns regarding mechanical problems. This information will be tracked and prioritized.	Same
SCADA - Leak Detection Manual	The Leak Detection Manual shall be prepared using guidance provided in Canadian Standards Association, Oil and Gas Pipeline Systems, CSA 2662-03, Annex E, Section 8.5.2, Leak Detection Manual	Same
Mainline Valve Control	Mainline valves located on either side of a pipeline segment containing an HCA where personnel response time to the valve exceeds one hour must be remotely controlled by the SCADA system. The SCADA system must be capable of opening and closing the valve and monitoring the valve position, upstream pressure and downstream pressure.	Same
Pipeline Inspection	The pipeline must be capable of passing in line inspection (ILI) tools. All headers and other segments covered under this special permit that do not allow the passage of an ILI device must have a corrosion mitigation plan	Same
Internal Corrosion	Keystone shall limit sediment and water (S&W) to 0.5 percent by volume and report S&W testing results to PHMSA in the 180-day and annual reports. Keystone shall also report upset conditions causing S&W level excursions above the limit. This report shall also contain remedial	Same

Category	Keystone Pipeline Special Permit	Keystone XL Pipeline Parameters
	measures Keystone has taken to prevent a recurrence of excursions above the S&W limits. Keystone must run cleaning pigs twice in the first full year of operation and as necessary in succeeding years based on the analysis of oil constituents, weight loss coupons located in areas with the greatest internal corrosion threat and other internal corrosion threats. Keystone will send their analyses and further actions, if any, to PHMSA.	
Cathodic Protection	The initial CP system must be operational within six months of placing a pipeline segment in service	Same
Interference Current Surveys	Interference surveys must be performed within six months of placing the pipeline in service to ensure compliance with applicable NACE International Standard Recommended Practices0 169 and0177 (NACE RP 0169 and NACE RP 0177) for interference current levels. If interference currents are found, Keystone will determine if there have been any adverse affects to the pipeline and mitigate the affects as necessary. Keystone will report the results of any negative finding and the associated mitigative efforts to the appropriate PHMSA regional office	Same
Corrosion Surveys	Corrosion surveys of the affected pipeline must be completed within six months of placing the respective CP system(s) in operation to ensure adequate external corrosion protection per NACE RP 0169. The survey will also address the proper number and location of CP test stations as well as AC interference mitigation and AC grounding programs per NACE RP 0177. At least one CP test station must be located within each HCA with a maximum spacing between test stations of one-half mile within the HCA. If placement of a test station within an HCA is impractical, the test station must be placed at the nearest practical location. If any annual test station reading fails to meet 49 CFR 195, Subpart H requirements, remedial actions must occur within six months. Remedial actions must include a close interval survey on each side of the affected test station and all modifications to the CP system necessary to ensure adequate external corrosion control	Same
Initial Close Interval Survey (CIS) - Initial	A CIS must be performed on the pipeline within two years of the pipeline in-service date. The CIS results must be integrated with the baseline	Same

Category	Keystone Pipeline Special Permit	Keystone XL Pipeline Parameters
	ILI to determine whether further action is needed	
Pipeline Markers	Keystone must employ line-of-sight markings on the pipeline in the special permit area except in agricultural areas or large water crossings such as lakes where line of sight markers are impractical. The marking of pipelines is also subject to Federal Energy Regulatory Commission orders or environmental permits and local restrictions. Additional markers must be placed along the pipeline in areas where the pipeline is buried less than 42 inches	Same
Monitoring of Ground Movement	An effective monitoring/mitigation plan must be in place to monitor for and mitigate issues of unstable soil and ground movement	Same
Initial In-Line Inspection (ILI)	Keystone must perform a baseline ILI in association with the construction of the pipeline using a high-resolution Magnetic Flux Leakage (MFL) tool to be completed within three years of placing a pipeline segment in service. The high resolution MFL tool must be capable of gouge detection. Keystone must perform a baseline geometry tool run after completion of the hydrostatic strength test and backfill of the pipeline, but no later than six months after placing the pipeline in service under a special permit. The ILI data summary sheets and planned digs with associated ILI tool readings will be sent to the PHMSA regional office. The PHMSA regional office will be given at least 14 days notice before confirmation digs are executed on site. The dimensional data and other characteristics extracted from these digs will be shared with the PHMSA regional office. Keystone will also compare dimensional data and other characteristics extracted from the digs and compare them with ILI tool data. If there are large variations between dig data and ILI tool data, Keystone will submit PHMSA a plan on further actions, inclusive of more digs, to calibrate their analysis and remediation process.	Same
Future ILI	Future ILI inspection must be performed on the entire pipeline subject to the special permit, on a frequency consistent with 49 CFR 195.452Q)(3), assessment intervals, or on a frequency determined by fatigue studies based on actual operating conditions, inclusive of flaw and corrosion growth models	Same
Verification of Reassessment interval	Keystone must submit a new fatigue analysis validate the pipeline reassessment interval annually for the first five years after placing the	Same

Category	Keystone Pipeline Special Permit	Keystone XL Pipeline Parameters
	pipeline subject to this special permit in service. The analysis must be performed on the segment experiencing the most severe historical pressure cycling conditions using actual pipeline pressure data.	
Fatigue	Two years after the pipeline in-service date, Keystone will use all data gathered on pipeline section experiencing the most pressure cycles to determine effect on flaw growth that passed manufacturing standards and installation specifications. This study will be performed by an independent party agreed to by Keystone and PHMSA headquarters. Furthermore, this study will be shared with PHMSA headquarters as soon as practical after its completion, preferably before baseline assessment begins. These findings will determine if an ultrasonic crack detection tool must be launched in that pipeline section to confirm crack growth with Keystone's crack growth predictive models.	Same
Direct Assessment Plan	Headers, mainline valve bypasses and other sections covered by this special permit that cannot accommodate ILI tools must be part of a Direct Assessment (DA) plan or other acceptable integrity monitoring method using External and Internal Corrosion Direct Assessment criteria (ECDA/ICDA).	Same
Damage Prevention	The Common Ground Alliance (CGA) damage prevention best practices applicable to pipelines must be incorporated into the Keystone's damage prevention program.	Same
Anomaly Evaluation and Repair	Anomaly evaluations and repairs in the special permit area must be performed based upon the following: a) Immediate Repair Conditions: Follow I95.452(h)(4)(i) except designate the calculated remaining strength failure pressure ratio (FPR) = < 1.16; b) 60-Day Conditions: No changes to 195.452(hXaXii); c) 180-DayConditions: Follow I95.452(H)(4xiii) with exceptions for the following conditions which must be scheduled for repair within 180 days: - Calculated FPR = < I.32 - Areas of general corrosion with predicted metal loss greater than 40 percent - Predicted metal loss is greater than 40 percent of nominal wall that is located at a crossing of another pipeline - Gouge or groove greater than 8 percent of	Same

Category	Keystone Pipeline Special Permit	Keystone XL Pipeline Parameters
	nominal wall d) Each anomaly not repaired under the immediate repair requirements must have a corrosion growth rate and ILI tool tolerance assigned per the Integrity Management Program (IMP) to determine the maximum re-inspection interval. e) Anomaly Assessment Methods: Keystone must confirm the remaining strength (RSTRENG) effective area,R -STRENG - 0.85dL and ASME B31G assessment methods are valid for the pipe diameter, wall thickness, grade, operating pressure, operating stress level and operating temperature. f) Keystone must also use the most conservative method until confirmation of the proper method is made to PHMSA headquarters. Flow Stress: Remaining strength calculations for X-80 pipe must use a flow stress equal to the average of the ultimate (tensile) strength and the SMYS. g) Dents: For initial construction and the initial geometry tool run, any dent with a depth greater than2 percent of the nominal pipe diameter must be removed unless the dent is repaired by a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe. For the purposes of this condition, a "dent" is a depression that produces a gross disturbance in the curvature of the pipe wall without reducing the pipe wall thickness. The depth of the dent is measured as the gap between the lowest point of the dent and the prolongation of the original contour of the pipe.	
Reporting - Immediate	Keystone must notify the appropriate PHMSA regional office within 24 hours of any non-reportable leaks originating in the pipe body in the special permit area	Same
Reporting – 180 Days	Reporting - 180 Day: Within 180 days of the pipeline in-service date under a special permit, Keystone shall report on its compliance with special permit conditions to PHMSA Headquarters and the appropriate regional office. The report must also include pipeline operating pressure data, including all pressures and pressure cycles versus time. The data format must include both raw data in a tabular format and a graphical format. Any alternative formats must be approved by PHMSA	Same

Category	Keystone Pipeline Special Permit	Keystone XL Pipeline Parameters
	headquarters.	
Annual Reporting	Following approval of the special permit, Keystone must annually report the following: a) The results of any ILI or direct assessment results performed within the special permit area during the previous year; b) The results of all internal corrosion management programs including the results of: - S&W analyses - Report of processing plant upset conditions where elevated levels of S&W are introduced into the pipeline - Corrosion inhibitor and biocide injection - internal cleaning program - Wall loss coupon tests c) Any new integrity threats identified within the special permit area during the previous year; d) Any encroachment in the special permit area, including the number of new residences or public gathering areas; e) Any HCA changes in the special permit area during the previous year; f) Any reportable incidents associated with the special permit area that gccurred during the previous year; g) Any leaks on the pipeline in the special permit area that occurred during the previous year; h) A list of all repairs on the pipeline in the special permit area during the previous year; i) On-going damage prevention initiatives on the pipeline in the special permit area and a discussion of their success or failure; j) Any changes in procedures used to assess and/or monitor the pipeline operating under this special permit; k) Any company mergers, acquisitions, transfers of assets, or other events affecting the regulatory responsibility of the company operating the pipeline to which this special permit applies; and l) A report of pipeline operating pressure data to include all pressures and pressure cycles versus time. The data format must include both raw data in a tabular format and a graphical format. Any alternative formats must be approved by PHMSA headquarters	Same

Discussion

Current Keystone Oil Pipeline Special Permit PHMSA 2006-26617 Condition #5

Steel Plate Quality Control:

The steel mill and/or pipe rolling mill must incorporate a comprehensive plate/coil mill and pipe mill inspection program to check for defects and inclusions that could affect the pipe quality. This program must include a plate or rolled pipe (body and all ends) ultrasonic testing (UT) inspection program per ASTM ,4'578 to check for imperfections such as laminations. An inspection protocol for centerline segregation evaluation using a test method referred to as slab macro-etching must be employed to check for inclusions that may form as the steel plate cools after it has been cast. A minimum of one macro-etch or a suitable alternative test must be performed from the first or second heat (manufacturing run) of each sequence (approximately four heats) and graded on the Mannesmann scale or equivalent. Test results with a Mannesmann scale rating of one or two out of a possible five scale are acceptable

Suggested Alternate Wording:

Steel Plate Quality Control:

The steel mill and/or pipe rolling mill must incorporate a comprehensive plate/coil mill and pipe mill inspection program to check for defects and inclusions that could affect the pipe quality. This program must include a plate or rolled pipe (body and all ends) ultrasonic testing (UT) inspection program per ASTM ,4'578 to check for imperfections such as laminations. An inspection protocol for centerline segregation evaluation using a test method referred to as slab macro-etching must be employed to check for inclusions that may form as the steel plate cools after it has been cast. A minimum of one macro-etch or a suitable alternative test must be performed from the first or second heat

~~(manufacturing run)~~ of each ***casting*** sequence ~~(approximately four heats)~~ and graded on the Mannesmann scale or equivalent. Test results with a Mannesmann scale rating of one or two out of a possible five scale are acceptable

The alternate wording allows for the steel supplier's casting sequence to determine the frequency. In a longer casting sequence test would be performed at the start and end to ensure confidence in quality for the heats in between. As part of the KXL application PHMSA technical review process, the recent submissions from industry groups could be used to refine this condition.

<u>Current Keystone Oil Pipeline Special Permit PHMSA 2006-26617 Condition #6</u>

Pipe Seam Quality Control:

A quality assurance program must be instituted for pipe weld seams. The pipe weld seam tests must meet the minimum requirements for tensile strength in API5L for the appropriate pipe grade properties. A pipe weld seam hardness test using the Vickers hardness testing of a cross-section from the weld seam must be performed on one length of pipe from each heat. The maximum weld seam and heat affected zone hardness must be a maximum of 280 Vickers hardness(Hv10). The hardness tests must include a minimum of two readings for each heat affected zone, two readings in the weld metal and two readings in each section of pipe base metal for a total of 10 readings. The pipe weld seam must be 100 percent UT inspected after expansion and hydrostatic testing per APL 5L

Suggested Alternate Wording:

Pipe Seam Quality Control:

A quality assurance program must be instituted for pipe weld seams. The pipe weld seam tests must meet the minimum requirements for tensile strength in API5L for the appropriate pipe grade properties. ***Manufacturing procedures must require qualification of the welding procedures to ASME Section IX to ensure seam quality.*** A pipe weld seam hardness test using the Vickers hardness testing of a cross-section from the weld seam must be performed on one length of pipe from each heat. The maximum weld seam and heat affected zone hardness must be a maximum of ~~280~~ ***350*** Vickers hardness(Hv~~10~~ ***1000g***). The hardness tests must include a minimum of two readings for each heat affected zone, two readings in the weld metal and two readings in each section of pipe base metal for a total of 10 readings. The pipe weld seam must be 100 percent UT inspected after expansion and hydrostatic

The alternate wording would accommodate the use of high strength pipe such as X80, presently the current conditions limit the possibility of the high strength steels offered by approved TransCanada suppliers. TransCanada would like to explore revisions to this condition during PHMSA's technical review process.

TransCanada

Appendix E

Puncture Resistance Calculation

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Puncture Resistance Calculation

The puncture resistance calculation was completed using Equation 6.4, of PRCI PR-244-9729 "Reliability-based Prevention of Mechanical Damage to Pipelines" study.

$$R = [1.17 - 0.0029\,(D/T)]\,(L + W)\,T\,\sigma_u + E_R$$

Where :

T = pipe wall thickness,

D = pipe diameter,

σ_u = tensile strength,

L = bucket tooth length, and

W = width of tooth

ER is the model error (random variable), taken as 0 for deterministic calculations.

Excavator tooth size is 3.54 in x 0.137 in

X70, SMTS = 82 ksi

X80, SMTS = 90 ksi

Keystone XL design parameters for 72 percent SMYS and 80 percent SMYS are noted below:

Diameter (in)	***API 5L Grade***	***MAOP (psi)***	**Wall Thickness at 80SMYS (inch)**	**Wall Thickness at 72 SMYS (inch)**
36	X80	1440	0.405	0.450
36	X70	1440	0.463	0.514

Table 1 – Keystone XL Design Parameters

The puncture resistance is given in tons in the following table

Diameter (in)	*API 5L Grade*	R in kN 72 SMYS	R in kN 80 SMYS
36	X80	650	569
36	X70	692	609

Table 2 - Puncture resistance for 72 SYMS and 80 SMYS

In an industry survey[1], it was found that about 98% of 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. The puncture resistance for the Keystone XL pipeline is greater than 40 tons for all the design cases, and comfortably exceeds the recommended resistance target for maximum digging force, equivalent to an excavator weight between 35 and 60 tons[2].

Diameter (in)	*API 5L Grade*	Keystone XL Wall Thickness at 80SMYS (in)	75th Percentile Puncture Resistance Minimum Wall Thickness (in)[2]
36	X80	0.405	0.260
36	X70	0.463	0.280

Table 3 - Comparison of Keystone XL wall thickness to recommended target level for 75th percentile penetration resistance

Keystone XL exceeds the criteria for "no additional protective measures required to mitigate puncture", as shown in table 3. However, Keystone XL will use several additional measures as part of its integrity management program (IMP) to mitigate the risk of excavation damage to the pipeline:

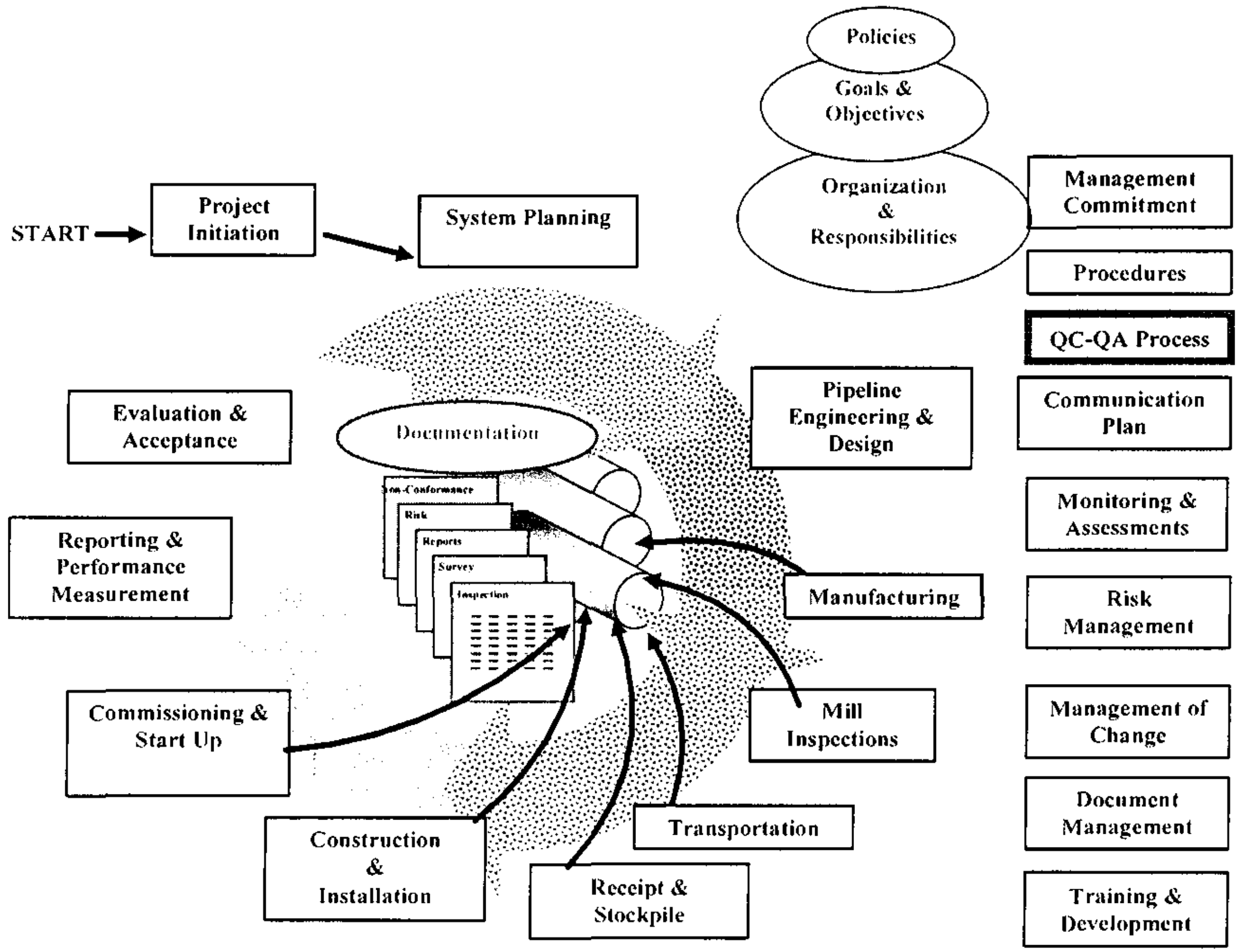
[1] PRCI PR-244-9729 Reliability-based Prevention of Mechanical Damage to Pipelines

[2] J. Kiefner. Impact of 80% SMYS Operation on Resistance to Third Party Mechanical Damage. March 21, 2006.

- Depth of cover of the pipeline will be 4ft with the exception of areas with consolidated rock in which the depth of cover will be 3ft.
- Implementing the TransCanada Integrated Public Awareness program for the Keystone XL Pipeline system.
- Participating in one-call and local damage prevention programs.
- Employing additional close-spaced visible signage in select locations as determined by the high consequence area analysis. All other areas will employ visible signage as per 49 CFR 195.410.
- Using warning tape buried above pipe depth in select locations as determined by a quantitative risk assessment.
- Implementing TransCanada's encroachment management processes for the Keystone XL Pipeline.
- Implementing an aerial inspection program, at a frequency determined by TransCanada's risk management process and in accordance with 49 CFR § 195.412, to inspect pipeline facilities and observe surface conditions on or adjacent to the right-of-way.

Appendix F

Quality Control Plan Schematic



Appendix G

Pipeline Threat Analysis

TransCanada

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1.1 Corrosion

The estimation of corrosion failure frequency was derived through the use of industry failure data. This approach to corrosion failure frequency estimation is inherently conservative, as the industry dataset contains a mixture of pipe from several eras, comprising many coating types and subjected to a variable range of operating and integrity management practices. Of these factors, coating type, coupled with adequate cathodic protection, has the greatest influence on the pipeline's failure frequency for corrosion. Coating type coupled with adequate cathodic protection are the primary means by which the pipe's surface is protected from the electrolyte present in the surrounding environment. TransCanada has yet to experience a corrosion-related operational incident on fusion bonded epoxy (FBE) coated portions of its mainline system, over the 25 years in which the coating system has been in operation. FBE is the coating system that will be used on Keystone XL's new pipeline construction.

Other significant influences on the rate of corrosion failure frequency include the environment in which the pipeline is installed and the state of the cathodic protection system used to minimize corrosion on the pipeline in the event of coating failure. (Internal Corrosion is discussed under section 1.5)

Corrosion related failures are a time dependant hazard that result from the accumulation of years of corrosion damage to the pipe wall. A change in design factor has no direct impact on the rate of corrosion, but does affect the critical flaw size required to rupture the pipe as well as lowering the wall thickness that the corrosion pit must penetrate to cause a leak. Design factor has virtually no impact on the total number of corrosion failures that a pipeline will experience by the end of its design life; only the timing of such incidents will be affected.

High resolution in-line inspection (ILI) tools can detect critical defects less than one-tenth of the critical defect size. Keystone will perform high resolution ILI on an inspection frequency as determined by a quantitative risk based analysis. TransCanada uses a risk-based approach that takes into account ILI sizing error and variability in corrosion growth rate in order to determine defect repair requirements and re-inspection intervals. As a result of this process, TransCanada frequently excavates and repairs select defects that pass the standard acceptance criteria used to evaluate features detected by high resolution ILI using magnetic flux leakage. This approach creates a greater risk reduction benefit than the small increase in risk between the 72 percent SMYS and 80 percent SMYS design cases. Using the 80 percent SMYS design case, there is no reason that any in-service corrosion failures should occur during Keystone XL's operations except under the most unusual of circumstances.

1.2 Excavation Damage

Failures due to excavation damage result from direct hits to the pipeline with sufficient force to puncture the pipe's wall or from no-leaking damage that has the potential to fail by potential growth mechanisms. A higher design factor reduces the puncture resistance of the pipe marginally as analysed in Appendix E. The main contributing factor to pipeline failure is the probability of a hit occurring. Keystone XL will employ several methods to reduce the likelihood of excavation damage, including:

- burial depth of the pipeline to a minimum of 4 feet in uplands and wetlands,
- an integrated public awareness program,
- participation in one call and local damage prevention programs
- regular aerial patrol of the pipeline ROW at a frequency set by TransCanada's risk management process, which meets or exceeds code requirements

- the use of warning tape buried above pipe depth overtop of the pipeline in select locations as determined by a quantitative risk assessment
- the use of close spaced, visible signage in select locations as determined by the high consequence area analysis
- collocation of the pipeline within existing pipeline/powerline corridors; the Keystone XL route is 45% collocated with existing facilities (AC, ground fault, and lightning mitigation devices/systems will be installed in areas along the powerline corridor in which the pipeline is susceptible to such influences/occurrences.)

Using the Pipeline Research Council International (PRCI) Mechanical Damage model the impact of utilizing Keystone XL's approach to mechanical damage prevention produces risk reduction benefits that exceed the incremental risk resulting from the 0.8 design case, as shown in table 2.

Damage Prevention Method	Standard Practice at 80 SMYS	TransCanada Keystone Practice at 80 SMYS	Delta Risk Reduction
Aerial Patrol	3.52E-05	3.30E-05 *(as determined by risk assessment)*	2.16E-06
Public Awareness	3.52E-05	2.54E-05 *(IPA Program)*	9.83E-06
Signage	3.52E-05	1.99E-05 *(Close Spaced – Specific continuous location as determined by risk assessment)*	1.53E-05
Warning Tape	3.52E-05	1.70E-05 *(Specific continuous location as determined by risk assessment*	1.82E-05

Table 2 – TransCanada Keystone XL Excavation Damage Risk Compared to Standard Practice as Defined by Code

As shown in the above table, the inclusion of close spaced signage or buried warning tape at key high risk locations each create a greater risk reduction benefit than the increase in risk shown in table 1 as a result of changing the design case. The combination of both approaches combined with TransCanada's Integrated Public Awareness Program results in a safer overall operation for Keystone XL by focusing on preventing pipeline line strikes.

Integrated Public Awareness (IPA) Program

Keystone XL will implement and utilize an IPA program as developed by TransCanada. The objective of the program is to inform key members of the public of the location of Keystone XL facilities and activities, in order to protect the public from injury, to prevent or minimize effects on the environment; to protect Company facilities from damage by the public; and to provide an opportunity for on-going public awareness. This program will meet or exceed the requirement for 49 CFR 195.440 or API RP1162.

The goals of the IPA program are:

- To reduce/minimize third party damage
- To inform affected landowners and communities of the location of the facility, the nature of the product transported, contact information for the company and what steps to take in the event of an emergency.
- To ensure emergency services agencies fully understand Keystone XL's emergency response procedures and how we work together during an emergency.
- To inform contractors of requirements for working on or near Keystone facilities.
- To maintain contact with landowners, community groups, contractors and Emergency Service agencies or are directly impacted by Keystone XL facilities or operations.

1.3 Environmentally Assisted Cracking

Environmentally Assisted Cracking (EAC) is a process that includes a combination of corrosion dissolution, hydrogen embrittlement, and fatigue to produce cracks in the pipe wall resulting in leak or rupture. EAC is usually axially oriented as a result of hoop stress but may be circumferentially oriented at bends or locations that are impacted by geotechnical stresses. EAC is an environmentally driven process; on new pipelines, the potential for EAC is limited by the very small amount of coating disbondment on the pipeline. In TransCanada's experience, the disbondment typically associated with FBE coated pipelines is usually very limited in extent and results in corrosion pitting. Coating disbondment of the kind needed to facilitate EAC is typically associated with excavation damage that does not cause immediate failure and is not reported. Keystone will investigate any sites showing signs of unauthorized excavation found through the aerial patrol program. Furthermore, Keystone XL will correlate MFL indications with areas of excavation activity and utilize this information to identify sites requiring investigative excavations. If warranted, Keystone XL will conduct a crack inspection tool run using ultrasonic technology. This technology has a proven record of identifying cracks in liquid pipelines.

1.4 Fatigue

Fatigue is addressed in Appendix H.

1.5 Commodity Specification and Integrity

The Keystone XL pipeline will transport two main commodities as defined by 49 CFR 195.1: heavy-oil blend, and synthetic crude. The heavy-oil blend is a mixture of bitumen and either condensate or synthetic crude, in proportions appropriate to meet a viscosity specification of

328 cP (350 cSt) at a temperature that will vary throughout the year, with a typical operating temperature ranging from minimum value of 32°F to and a maximum value of 158°F.

The commodities will be batched within the pipeline in a turbulent flow regime. Composite samples will be collected from all batches upon receipt and delivery. Chemical corrosion inhibitors, biocides, corrosion coupons or probes and pipeline cleaning tools will be used on an as required basis along with in-line inspection to detect and monitor internal corrosion.

In addition, Keystone XL has specified 0.5% S&W for commodities to be transported. This specification is half the typical US transportation practice of 1% S&W and increases the commodity quality and reduces the likelihood of internal corrosion. Random testing of samples for sulfur, micro carbon residue (MCR), total acid number (TAN) will be undertaken in order to monitor and asses pipeline system performance.

The characteristics of commodity types shipped are not considered as sour products with typical properties as follows:

Product	Standard Density	Reference Temperature	Viscosity at Reference Temperature		
	API	(°F)	45.5 °F	65.3 °F	77°F
328 cP (350 cSt at Annual Average Temperature)	18.9	45.5 65.3	350 800	170 350	116 230
Synthetic crude	31.1	n/a	10	7	-

Table 3 – Commodity Specification

1.6 Use of State of Industry In-Line Inspection Technology

TransCanada has utilized in-line inspection technology since the early 1990's to assess its pipeline system. Pipelines on the TransCanada system are inspected as determined by risk based methodologies using high resolution technologies for the purpose of internal and external corrosion management. Recently, TransCanada has been using MFL technology for as part its dent management program. The MFL signal analysis algorithms are now capable of sizing dents, indicating if a gouge is present in a dent, identifying cracking at 45 degrees or greater orientation, indicating if there is metal loss in a dent; and determining if the dent is on a girth weld or seam weld. Keystone XL will employ the use of this technology as part of its IMP for management of external corrosion, internal corrosion and dents.

APPENDIX H

TransCanada

TransCanada Keystone Pipeline, LP

Integrity Management Process

For Line Pipe Cyclic Fatigue Induced by Internal Pressure Cycles for the Keystone XL Oil Pipeline

October 10, 2008

TransCanada

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1. Introduction

This document, entitled the Keystone XL Integrity Management Process for Line Pipe Cyclic Fatigue Induced by Internal Pressure Cycles (Keystone XL IMP), describes the integrity management process that TransCanada Keystone Pipeline, LP (Keystone) will follow to determine the inspection and maintenance requirements for the Keystone XL Oil Pipeline to manage potential integrity threats resulting from line pipe fatigue induced by internal pressure cycles. The Keystone XL IMP for fatigue will protect the Keystone XL Pipeline with high confidence against integrity threats resulting from cyclic fatigue.

2. Overview

The Keystone XL IMP begins with a comprehensive quality management system (QMS) for pipeline design, material procurement and transportation, construction and commissioning. The implementation of the QMS provides for a pipeline free from initial manufacturing, transportation and construction flaws in exceedance of pre-defined tolerances and mechanical damage induced in the transportation and construction processes.

During the operational phase of the Keystone XL Pipeline, the Keystone XL IMP requires:

1. Data collection of pressure cycles at various locations along the pipeline system;
2. Periodic analysis of the line pipe fatigue induced by internal pressure cycles;
3. On-going confirmation that manufacturing flaws are not a threat of concern based on items 1 and 2; and
4. Inspection with in-line inspection (ILI) tool(s) or other applicable approaches and assessment for the potential threat of mechanical damage.

3. Prediction of Remaining Fatigue Life and Assessment Interval

In addition to the rules in CFR 49 Part 195 that are applicable to high consequence areas (HCAs), fatigue life prediction is used as the primary determinant of the interval for assessments. The process for fatigue life prediction to be used for Keystone XL IMP is described in this section.

The overall process for fatigue assessment and management is represented in the flow diagram as shown in Figure 1.

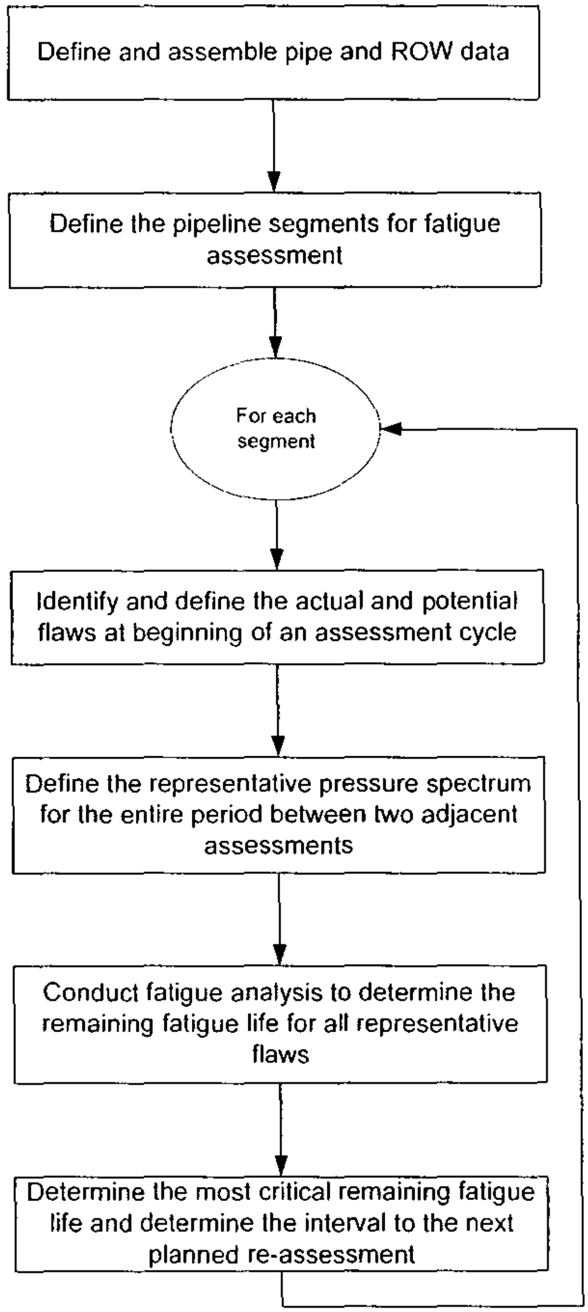

Figure 1 Overall Process for Fatigue Assessment and Management

Each of the elements in the overall process diagram above is further described in the following sub-sections.

3.1 Pipe and Right-of-Way (ROW) Data

Pipe data, including outside diameter (OD), wall thickness, grade, material properties, manufacturing procedure specification (MPS), mill certification, construction records and maximum operating pressure (MOP), will be documented along the pipeline system and made available for fatigue analysis. ROW data including milepost, elevation and HCA locations, will also be documented along the pipeline system and made available for fatigue analysis.

3.2 Pipeline Segments for Fatigue Assessment

The pipeline will divided into a number of segments for the purpose of fatigue assessment. The definition of pipeline segments may be varied from one assessment to the next; however, the combination of all segments will cover the entire pipeline. The pipeline segments for fatigue assessment will be defined based on the following considerations:

- HCA locations;
- Methods for assessment (ILI, hydrotest, or others);
- Location and distribution of the existing flaws;
- Pipeline attributes (e.g. pipe OD, wall thickness);
- Location of pump stations; and
- Pressure profile and spectrum.

3.3 Representative Flaws

Fatigue cracking is the term used to describe the process of initiation and growth of cracks induced by cyclic pressure. The initial size of cracks or crack-like flaws is one of the key factors with significant influence on the remaining fatigue life of a pipe. With the pipe properties and pressure spectrum expected for the Keystone XL Pipeline, a flawless pipeline would have fatigue life significantly longer than any conceivable operating life and therefore fatigue is not a potential integrity threat unless there is an initial flaw.

Potential causes for flaws in an operating pipeline include:

- Manufacturing and construction flaws that are considered to be acceptable on the basis of the inspection processes and flaw acceptance criteria established for pipe manufacturing and pipeline construction;
- Stress Corrosion Cracking (SCC) can affect some pipelines in operation at the present time. The primary protection against SCC is a good quality coating system that is cathodic protection (CP) friendly, combined with effective CP. The Keystone XL Pipeline will have fusion bond epoxy (FBE) coating and CP to provide effective protection against SCC. TransCanada Pipelines, Keystone's parent corporation, has operated FBE coated and CP protected pipelines for 25 years and no SCC has been found in these pipelines to date.
- Mechanical damage induced gouges may lead to crack-like flaws. The primary protection against mechanical damage is prevention of contact, and Keystone XL will have a mechanical damage prevention program as a part of TransCanada's overall integrity management program. The increased depth of cover for the project greatly reduces the frequency of mechanical damage incidents. Keystone recognizes, however, that rare incidents of mechanical damage are still possible and the initial flaws resulting from potential mechanical damage incidents will be considered in the fatigue analysis.

For the Keystone XL Pipeline, representative initial flaw sizes will be determined for the as-constructed condition and the beginning condition of a typical assessment cycle. For each condition, the representative initial flaw sizes are defined for existing flaws at the beginning of the assessment cycle and for flaws that could potentially occur during the assessment cycle.

As-Constructed Condition

Since the US portion of the Keystone XL Pipeline will be newly constructed, the maximum existing flaw sizes at the time the pipeline begins operation are limited by the flaw acceptance criteria for pipe manufacturing. The maximum flaw sizes based on mill flaw acceptance criteria are set out in Table 1, below:

Table 1 Maximum Flaw Sizes based on Flaw Acceptance Criteria for Pipe Manufacturing

Pipe size	Detection Threshold	Mill Flaw Acceptance Criteria
36 in OD	2" length by 0.016" depth	0.5" length by 0.019" depth

The predicted fatigue lives for all of these flaws under the design pressure spectrum (see Section 3.4) are in excess of 100 years upstream of Cushing Ok. and in excess of 70 years downstream of Cushing Ok. Accordingly, growth by fatigue of initial manufacturing flaws is not considered a threat of concern for the Keystone XL Pipeline. This conclusion will, however, be verified on an ongoing basis based on actual pressure cycles.

Mechanical damage induced flaws consist primarily of metal removal (gouge), in some cases associated with a very shallow crack. Keystone adopts a conservative approach and represents these flaws by cracks with the combined depth of the gouge and crack.

Accordingly, the representative initial flaw depth for flaws potentially induced by mechanical damage incidents is assumed to be 15% of the nominal wall thickness. This assumption represents a 96% non-exceedance probability, based a study published by Rosenfeld et al. (IPC 2006-10513, "Deterministic Assessment of Minor Mechanical Damage on Pipelines"). The representative initial crack length is assumed to be $\sqrt{(D.t)}$ inches, corresponding to 4.02 inches for a 36 inch OD pipeline. In addition, the initial flaw is conservatively assumed to be located within a dent with depth of 2% OD, which represents a 98.75% non-exceedance probability based on IPC 2006-10513 "Deterministic Assessment of Minor Mechanical Damage on Pipelines."

Both the existing flaws from manufacturing and construction processes and the potential flaws from mechanical damage incidents are random in location. Following a conservative approach, the design pressure spectrum will be applied in the fatigue analysis. The potential flaws from mechanical damage incidents are also random in time. Following a conservative approach, all potential flaws are assumed to occur at the beginning of the operation.

At the Beginning of an Assessment Cycle

At the beginning of a typical assessment cycle, the existing flaws are the remaining flaws after the inspection and repairs are completed. If the assessment method for the previous cycle was ILI and the remaining flaws are defined in terms of size and location, the specific size and location information coupled with a location-specific pressure spectrum can be used in the fatigue analysis. The uncertainty in inspection results will be properly addressed using industry recognised methods as discussed in reference material provided in the Keystone Pipeline Special Permit Application (Docket # PHMSA-2006-26617) - Appendix G.

The potential flaws from mechanical damage incidents are the same as defined in the previous sub-section. Following a conservative approach, these flaws are assumed to occur at the beginning of the assessment cycle and at locations where the most severe spectrum applies.

3.4 Pressure Spectrum

During the pipeline design and construction phases and during the early period of the operational phase of the Keystone XL Pipeline, the actual operational pressure spectrum of the pipeline will not be known. As a result, a design pressure spectrum constructed based on expected operating conditions, will be used for the initial fatigue analysis. The design pressure spectrum includes background pressure cycles typical of liquid pipelines and major cycles for operational requirements as defined in Table 2. The design pressure spectrum for 36 inch OD pipeline is plotted in Figure 2 and Figure 3.

Kiefner and Associates Inc. (KAI) conducted a comparative analysis of the proposed spectrum constructed based on the expected operating conditions to those associated with the pressure cycles listed on a benchmarking scale given in Dealing with Low-Frequency-Welded ERW Pipe and Flash-Welded Pipe with Respect to HCA-Related Integrity Assessments (Kiefner, 2002). The results of this analysis placed the proposed Keystone XL pressure spectrum upstream of Cushing, OK into the aggressive category and downstream pressure spectrum into the very aggressive category.

Once the pipeline is in operation, actual pressure data will be recorded and analyzed. Representative pressure spectra based on the actual operating data will then be constructed and incorporated into the fatgue analysis. The pressure spectra data will not be time averaged and will capture the full amplitude of all pressure cycles. For location-specific pressure spectra, hydraulic gradients and elevation changes will also be taken into account in the fatigue analysis.

Pipe Specifications	Over Pressure Cycles		Complete Line S/D		Full Depressurization		Single Station S/D		Unit Change	
	Cycles/Year	Pressure (kPa)	Cycles/Year	Pressure (kPa)	Cycles/year	Pressure (kPa)	Cycles/Month	Pressure (kPa)	Cycles/Month	Pressure (kPa)
NPS 36 (upstream from Cushing)	3	1000	3	5800	1	9930	1	4800	93	2100
NPS 36 (downstream from Cushing)	3	1000	3	5800	1	9930	55	4800	39	2100

Table 2 Predicted Major Pressure Cycles

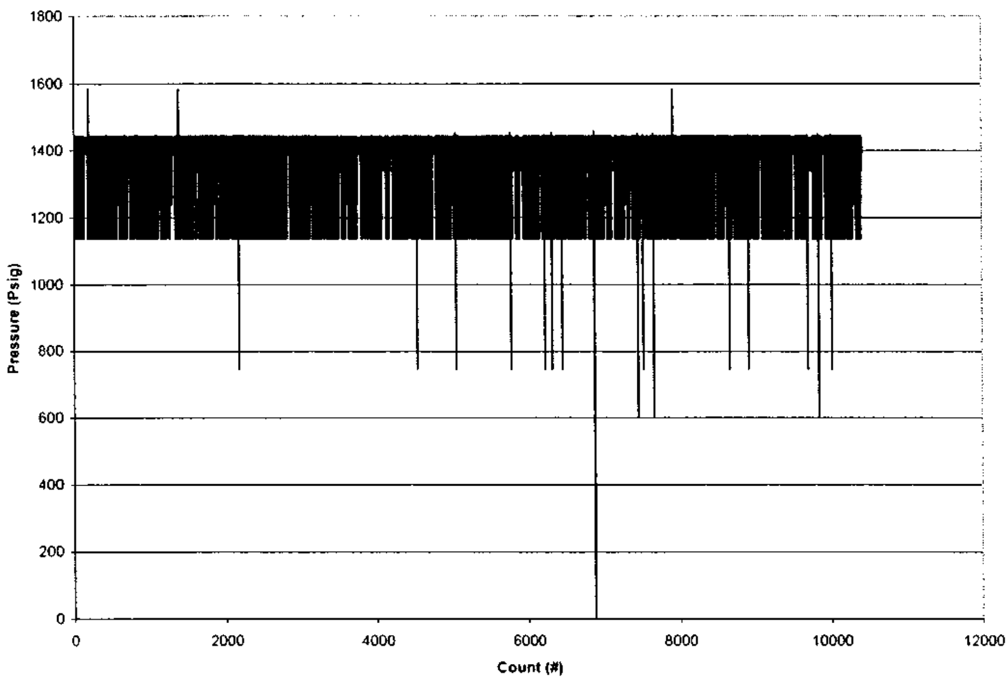

Figure 2 Design Pressure Spectrum for 36 Inch OD Pipeline for One Year – Upstream of Cushing Ok.

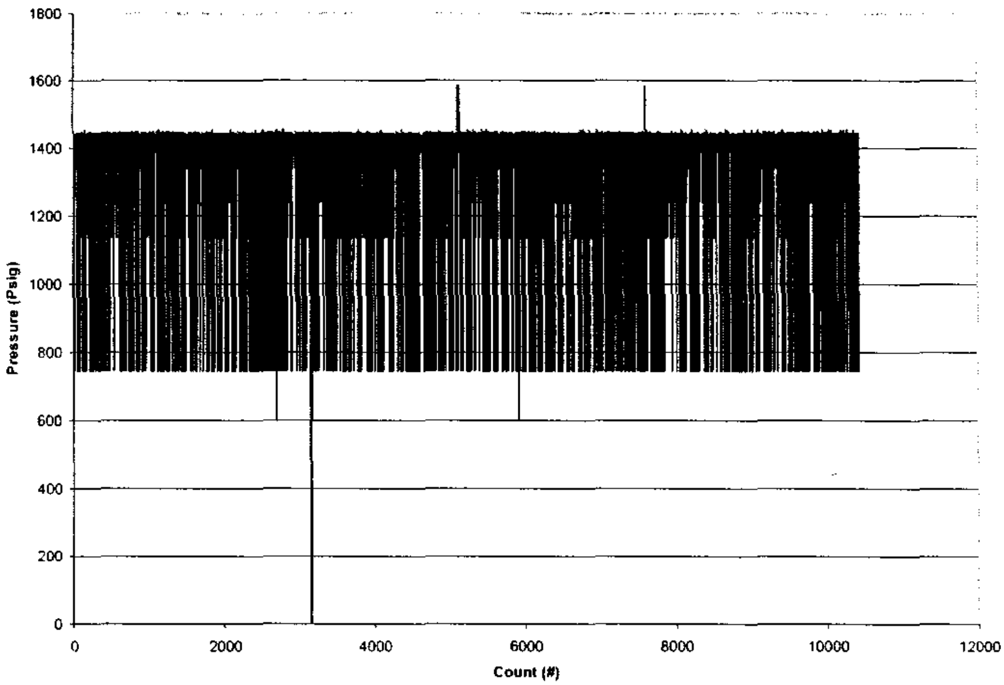

Figure 3 Design Pressure Spectrum for 36 Inch OD Pipeline for One Year – Downstream of Cushing Ok.

3.5 Fatigue Analysis

The fatigue analysis will be based on a well established model summarized in a paper published by Kiefner et al. (IPC2004-0167, "Estimating Fatigue Life for Pipeline Integrity Management").

As fatigue models develop, Keystone XL will continue to utilize fatigue analysis models and procedures that are validated and industry accepted.

3.6 Continued Confirmation of Fatigue Assessment for Manufacturing Flaws

The confirmation of fatigue assessment for manufacturing flaws will be conducted annually for the first 5 years and at appropriate intervals thereafter for each of the defined segments in accordance with the following steps:

- Conduct fatigue analyses for all representative manufacturing flaws as defined in Section 3.3 and determine the remaining fatigue life for each flaw;
- Determine the most critical remaining fatigue life;
- Divide the most critical remaining fatigue life by a safety factor of 1.5 to determine the allowable remaining fatigue life; and
- Confirm the allowable remaining fatigue life is greater than the anticipated remaining operating life.

3.7 Interval for the Next Assessment for Mechanical Damage

The interval for the next planned assessment for mechanical damage will be determined for each of the defined segments in accordance with the following steps:

- Conduct fatigue analyses for pre-defined mechanical damage flaws;
- Determine the most critical remaining fatigue life;
- Divide the most critical remaining fatigue life by a safety factor of 1.5 to calculate a reassessment interval;
- If the segment contains an HCA, and the calculated reassessment interval is greater than permitted pursuant to CFR 49 Part 195, revise the interval to ensure compliance ; and

- If the segment does not contain an HCA, use the calculated reassessment interval.

4. Conservatism

In the Keystone XL IMP, a number of conservative assumptions are built into the fatigue analysis process to provide additional protection against integrity threats resulting from cyclic fatigue. These assumptions include:

- Mechanical damage induced flaws will occur in each of the assessment segments;
- Mechanical damage induced flaws will occur at the beginning of the assessment cycle;
- Mechanical damage induced flaws are represented by a crack with full depth of the damage (gouge plus crack), even though the metal loss is a much less severe condition for fatigue crack growth;
- Mechanical damage induced flaws have a 96% probability of being less than 15% of the nominal wall thickness;
- Mechanical damage induced flaws will be at a location where the critical pressure spectrum applies;
- Dent depths has 98.75% probability of being less than 2% OD;
- Fatigue crack growth rate based on API 579 or other rate that may be established based on actual pipe properties;
- Representative lower bound pipe properties (SMYS, SMTS, and CVN), , are used in fatigue analysis; and
- An appropriate safety factor is applied to the predicted remaining fatigue life.

During service, continuing advances in industry knowledge related to fatigue crack growth in pipelines, together with accumulated operating experience of the Keystone and Keystone XL pipelines, will be used to refine the fatigue analysis process.

Appendix I

Letter of Review

Kiefner & Associates, Inc.

September 22, 2008

Ms. Meera Kothari, P. Eng.
TransCanada PipeLines Ltd.
450 -1 Street SW
Calgary, Alberta, CANADA
T2P 5H1

Re: Review of the Keystone XL Oil Pipeline Integrity Management Process for Cyclic Fatigue Induced by Internal Pressure Cycles

Dear Ms. Kothari:

At your request, Kiefner & Associates, Inc. has reviewed the Integrity Management Process (IMP) to address cyclic fatigue induced by internal pressure cycles for the proposed U.S. portion of the Keystone XL (KXL) oil pipeline. Based on this review and predicated upon the successful implementation of the KXL quality management system, we find the IMP to be satisfactory for the purposes of managing the potential line pipe fatigue threat associated with initial manufacturing imperfections and from induced mechanical damage subjected to internal pressure cycles.

If you have further questions on this matter, please feel free to contact me.

Sincerely,

Michael J. Rosenfeld, PE
President

585 Scherers Court
Worthington, Ohio 43085
www.kiefner.com
Phone (614) 888-8220
Fax (614) 888-7323

Appendix J

FBE Lab Test Results

SHAW PIPE

A ShawCor Company

FBE Testing

Test	Manufacturer	Acceptance Criteria	Results	Average
28d Cathodic Disbondment @ 85°C[1]	3M	Customer Specifications	9.1mm 11.8mm 11.9mm	10.9mm
28d Cathodic Disbondment @ 80°C[2]	Dupont	Customer Specifications	13.5mm 12.1mm 14.1mm	13.2mm
28d Cathodic Disbondment @ 80°C[3]	3M	Customer Specifications	13.1mm 11.6mm 11.9mm	12.2mm
28d Cathodic Disbondment @ 95°C[4]	3M High Temp	20mm maximum radius*	5.9mm 5.31mm 6.1mm	5.77mm

Note: All are 14mils thickness

* As per CSA Z245.20-06

(1) Results are from July 2006, Project #TCA 06-04
(2) Results are from April 2006, Project #TCA 06-02
(3) Results are from November 2004, Project #TCA 04-09
(4) Results are from December 2006, Project #B-2006-02

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December 1, 2008

Robert Jones P.Eng.
Vice President
TransCanada Keystone Pipeline LP
450 1st Street SW
Calgary, Alberta, T2P 5H1
Canada

Jeff Wiese
Associate Administrator for Pipeline Safety
U.S. Department of Transportation
Pipeline and Hazardous Materials Safety Administration
East Building, 2nd Floor
1200 New Jersey Ave., SE
Washington, DC 20590

Re: Docket Number PHMSA 2008-0285
Amendment to Petition to Design, Construct and Operate the Keystone XL Oil Pipeline at 80% Specified Minimum Yield Strength (SMYS)

Dear Mr. Wiese,

Upon review of the Application to Design, Construct and Operate the Keystone XL Oil Pipeline at 80% Specified Minimum Yield Strength (SMYS), one omission has been identified. It is located within the petition section of the permit describing the pipeline segments to which the permit does not apply.

Keystone respectfully submits the attached corrections.

Best regards,

Robert Jones, P.Eng.
Vice President, TransCanada Keystone Pipeline LP

cc:Bill Gutte, Deputy Associate Administrator, PHMSA
Alan Mayberry, Director – Engineering & Emergency Support, PHMSA
John Gale, Director – Regulations, PHMSA
Ivan Huntoon – Director, Central Region, PHMSA
Rodrick Seeley – Director, South West Region, PHMSA
Chris Hoidal – Director, Western Region, PHMSA

Amendment to October 10, 2008 Special Permit Application

Original Petition Application Page 3

Pursuant to Section 60118 of the *Pipeline Safety Act*, 49 U.S.C § 60118, TransCanada Keystone Pipeline, LP (Keystone) hereby files with the Pipeline and Hazardous Materials Safety Administration (PHMSA) this request for a special permit relative to the regulations in 49 C.F.R. § 195.106 (2005), so as to permit Keystone to design, construct and operate the Keystone XL Pipeline, at hoop stresses up to 80 percent of the specified minimum yield strength (SMYS) for mainline pipe totaling approximately 1,375 miles of new 36-inch pipeline A special permit is requested for all mainline and extension facilities other than those described below:

a. pipeline segments that will operate in high consequence areas described as High Population Areas and Other Populated Areas as defined by 49 CFR §195.450;
b. pipeline segments that will operate in Commercially Navigable Waterways and in waterbodies greater than 100 feet in width of the stream as defined by 49 C.F.R. §195.450
c. pipeline segments that will operate at highway, railroad and road crossings; and
d. pump station, mainline valve, pigging, and measurement piping.

   These facilities will be designed, constructed and operated in accordance with 49 C.F.R. § 195.106 (2005) at hoop stresses up to 72 percent of the SMYS

Amended Section to Petition Application Page 3

Pursuant to Section 60118 of the *Pipeline Safety Act*, 49 U.S.C § 60118, TransCanada Keystone Pipeline, LP (Keystone) hereby files with the Pipeline and Hazardous Materials Safety Administration (PHMSA) this request for a special permit relative to the regulations in 49 C.F.R. § 195.106 (2005), so as to permit Keystone to design, construct and operate the Keystone XL Pipeline, at hoop stresses up to 80 percent of the specified minimum yield strength (SMYS) for mainline pipe totaling approximately 1,375 miles of new 36-inch pipeline A special permit is requested for all mainline and extension facilities other than those described below:

a. pipeline segments that will operate in high consequence areas described as High Population Areas and Other Populated Areas as defined by 49 CFR §195.450;
b. pipeline segments that will operate in Commercially Navigable Waterways and in waterbodies greater than 100 feet in width of the stream as defined by 49 C.F.R. §195.450
c. pipeline segments that will operate at highway, railroad and road crossings; ~~**and**~~
d. **pipeline segments operating immediately downstream and at lower elevations than a pump station; and**
e. pump station, mainline valve, pigging, and measurement piping.

These facilities will be designed, constructed and operated in accordance with 49 C.F.R. § 195.106 (2005) at hoop stresses up to 72 percent of the SMYS

Original Petition Application Page 22

Keystone requests a special permit in relation to 49 C.F.R. § 195.106, to the extent necessary to permit Keystone to design, construct, and operate the approximately 1375 miles of the Keystone XL mainline pipe at hoop stresses up to 80 percent of the SMYS in the United States. Keystone's request for a special permit applies to all Keystone XL facilities other than those described below:

a. pipeline segments that will operate in high consequence areas described as High Population Areas and Other Populated Areas as defined by 49 C.F.R. § 195.450;
b. pipeline segments that will operate in Commercially Navigable Waterways as defined in 49 CFR § 195.450 and in waterbodies greater than 100 feet in width of the stream as defined by 49 C.F.R. §195.450;
c. pipeline segments that will operate at highway, railroad and road crossings; and
d. pump station, mainline valve, pigging, and measurement piping.

These facilities will be designed, constructed and operated in accordance with 49 C.F.R. § 195.106 (2005) at hoop stresses up to 72 percent of the SMYS.

Amended Section to Petition Application Page 22

Keystone requests a special permit in relation to 49 C.F.R. § 195.106, to the extent necessary to permit Keystone to design, construct, and operate the approximately 1375 miles of the Keystone XL mainline pipe at hoop stresses up to 80 percent of the SMYS in the United States. Keystone's request for a special permit applies to all Keystone XL facilities other than those described below:

a. pipeline segments that will operate in high consequence areas described as High Population Areas and Other Populated Areas as defined by 49 CFR §195.450;

b. pipeline segments that will operate in Commercially Navigable Waterways and in waterbodies greater than 100 feet in width of the stream as defined by 49 C.F.R. §195.450

c. pipeline segments that will operate at highway, railroad and road crossings; ~~**and**~~

d. pipeline segments operating immediately downstream and at lower elevations than a pump station; and

e. pump station, mainline valve, pigging, and measurement piping.

These facilities will be designed, constructed and operated in accordance with 49 C.F.R. § 195.106 (2005) at hoop stresses up to 72 percent of the SMYS.

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Appendix C

System Map

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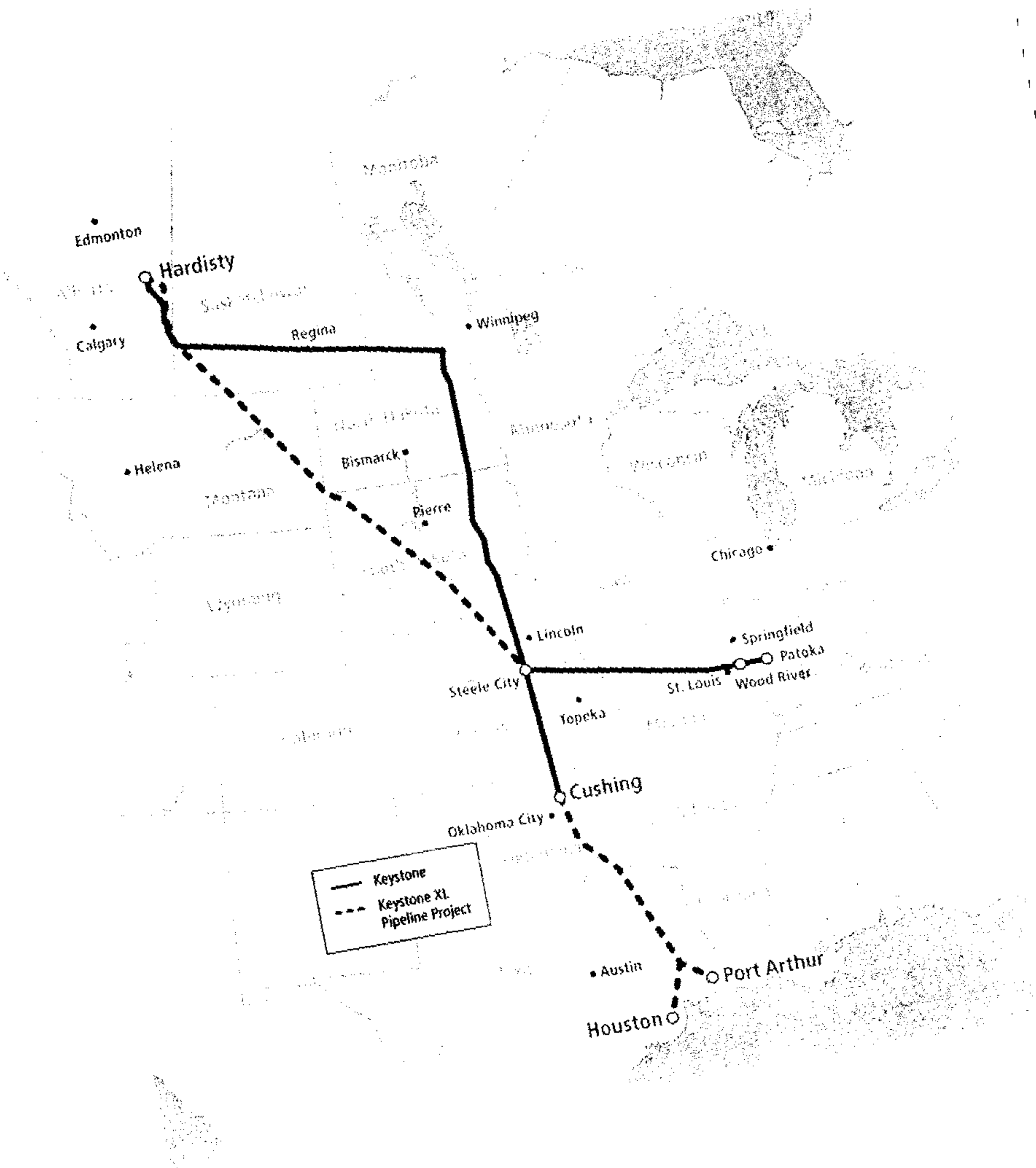


Exhibit H

ARTICLE 4

QUALITY

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 will be permitted in the Pipeline System. Shipper will not Tender to Carrier, 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/m^3); (v) the kinematic viscosity shall not exceed three hundred and fifty (350) square millimeters per second (mm^2/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.

Exhibit I

2.4 Pipeline Route Selection

The proposed route for the Project was developed through an iterative, multidisciplinary route selection process. This process involved the systematic identification of objectives, control points, collection of data, review of alternatives, and continual reassessment of these factors as refinement occurred. Additionally, the process unfolded in two distinct phases given modifications to basic Project objectives which had significant impacts on suitable routing alternatives. The process followed by Keystone is described in the following text.

2.4.1 Route Selection and Alternatives Analysis

Several high-level objectives influenced the selection of the proposed Project pipeline route. The location of the source of the crude oil in Canada, the location of planned border crossing facilities into the US (the preferred border crossing location is adjacent to the Northern Border pipeline border crossing at Morgan, Montana), and the delivery points for the crude oil (Cushing, Oklahoma, and the Nederland and Houston Ship Channel areas in Texas) influenced the initial route proposed for the Project.

Data Gathering

Based on these basic objectives, a general geographic region of interest was established. Data was then gathered for this region. These data included the following:

- Recent (2008) high resolution aerial photography, as well as aerial imagery from 2004 and 2005;
- United States Geological Survey (USGS) Topographic Quadrangle Maps;
- Delorme State Atlas and Gazetteers;
- Soil Survey Geographic (SSURGO) Database;
- National Land Cover Database (NLCD 2001);
- Additional GIS layers containing public data obtained from various county, state, and federal government websites; commercial background data provided by ESRI; and internal existing utility data; and
- NWI Database and Mapping.

All data were compiled into a GIS-based constraint data set of the area to support the identification and evaluation of route options.

Constraints and Opportunities

A number of primary and secondary constraints were identified to guide the route selection process. The route should avoid the constraints whenever possible and minimize contact when unavoidable. The constraints include:

Primary

- Co-location;
- Public lands in all states except Montana (federal and state);
- Large waterbodies and water control structures;
- Lands with permitting processes that could affect schedule;
- Extreme terrain;
- Large wetland complexes;

- Urban areas;
- Properties listed on the NHRP; and
- Wildlife refuges and management areas.

Secondary

- Water crossings;
- Wetland crossings;
- Waterfowl production areas;
- Irrigated croplands;
- Bedrock;
- Rural communities;
- Aquifers;
- Extensive forested areas, including commercial forest lands; and
- Residences and associated features such as driveways, outbuildings, and wind breaks.

Opportunities refer to those features which are favorable features for pipeline routing and generally serve to simplify construction and decrease disturbance. These include:

- Existing linear features such as pipelines (preferred), power lines, and roadways;
- Flat or gently rolling terrain;
- Soils which can be readily excavated; and
- Areas lacking forested vegetation.

Definition of Control Points

The following control points served to define the route:

- Preferred US/Canada border crossing near Morgan, Montana;
- The Fort Peck Reservoir, Montana;
- Crossing the Niobrara River at locations not designated as wild and scenic;
- Opportunity to connect with the Keystone Cushing Extension, a portion of the Keystone Pipeline Project;
- Delivery point at Nederland, Texas; and
- Delivery point at Moore Junction, Texas.

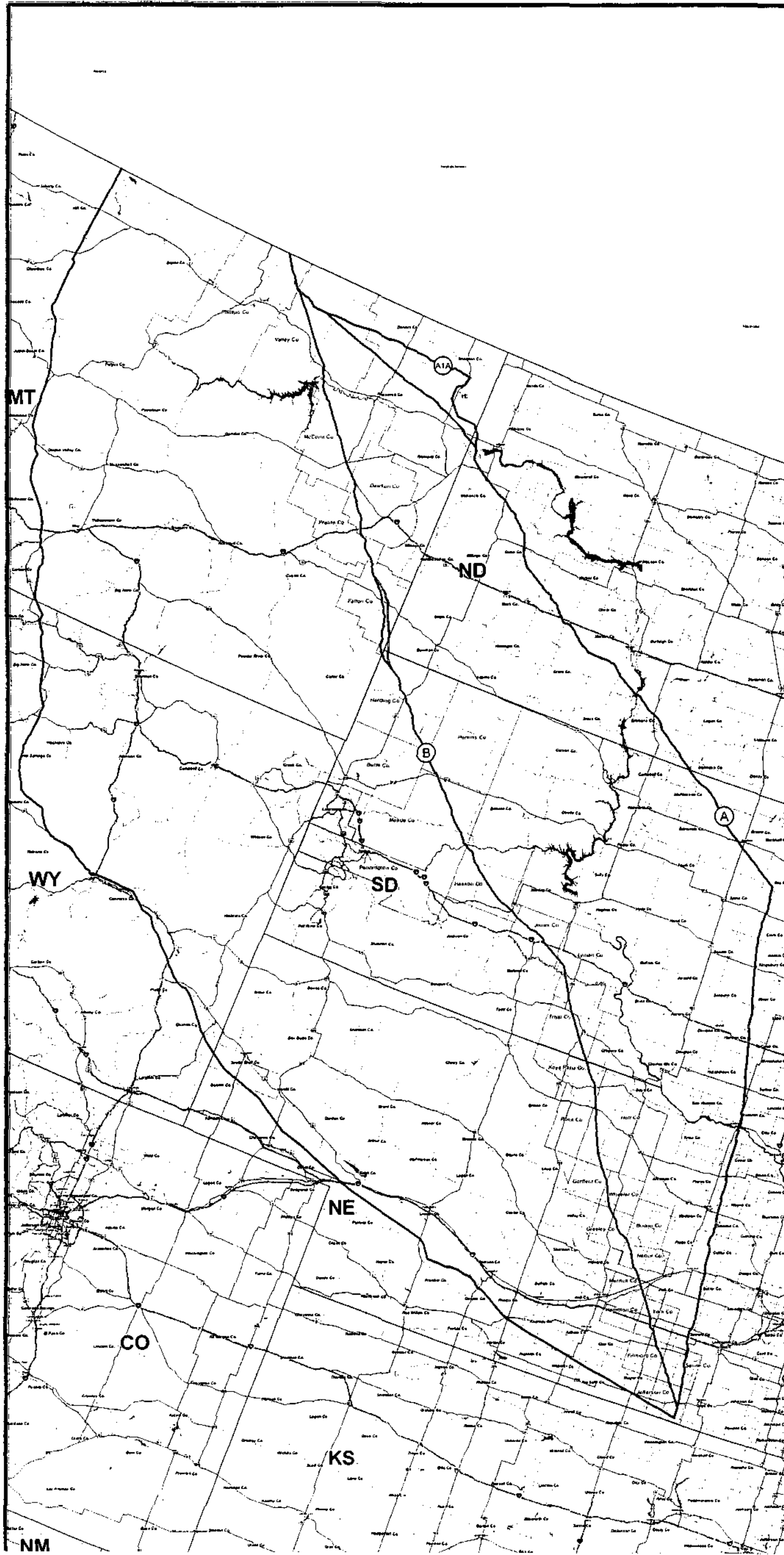
Route Alternatives Identification

Based on the above information and objectives, a number of route alternatives and alternative route segments were developed. These routes and route segments met the basic Project objectives and respected the constraints and opportunities to varying degrees.

The following paragraphs provide an overview of the characteristics of each of the major route alternatives and alternative route segments. These alternatives are illustrated on **Figures 2.4-1** through **2.4-4**.

Fig. 2.4-1

Keystone XL Project
CANADIAN SEGMENT
KEYSTONE XL STEELE CITY SEGMENT
KEYSTONE PIPELINE CUSHING EXTENSION
KEYSTONE XL GULF COAST SEGMENT
KEYSTONE XL HOUSTON LATERAL
MONTANA
NORTH DAKOTA
SOUTH DAKOTA
MINNESOTA
WYOMING
IOWA
NEBRASKA
MISSOURI
KANSAS
COLORADO
OKLAHOMA
NEW MEXICO
TEXAS
Fort Peck Indian Reservation
Little Missouri National Grassland
Standing Rock Indian Reservation
Crow Indian Reservation
Cheyenne River Indian Reservation
Black Hills National Forest
Thunder Basin National Grassland
Pine Ridge Indian Reservation
Buffalo Gap National Grassland
Superior National Forest
White River National Forest
Gunnison National Forest
Rio Grande National Forest
Santa Fe National Forest
Cibola National Forest
White Sands Missile Range
Osage Indian Reservation
Mark Twain National Forest
Ozark National Forest
Ouachita National Forest
PS-09
PS-10
PS-11
PS-12
PS-13
PS-14
PS-15
PS-16
PS-17
PS-18
PS-19
PS-20
PS-21
PS-22
PS-23
PS-24
PS-25
PS-26
PS-27
PS-29
PS - 32
PS - 33
PS - 34
PS - 35
PS - 36
PS - 37
PS - 38
PS - 39
PS - 40
PS - 41
This map is an illustration of the Keystone XL Project as of February 15, 2009.
The route will continue to be refined based on consultation with stakeholders and engineering design.
70 35 0 70 Miles
Legend
Keystone XL Project
Keystone Cushing Extension
Pump Stations
Major Highways
Limited Access
Streams and Rivers
Lakes
Federal Lands (Areas)
Forest Service
Department of Defense
Bureau of Land Management
Fish and Wildlife Service
National Park Service
Bureau of Indian Affairs
Bureau of Reclamation
Other Agencies (NASA, DOE, DOT, DOP, TVA)
TransCanada
ConocoPhillips



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KEYSTONE XL PROJECT
MORGAN, MT
TO
STEELE CITY, NE

N
W
E
S

0 30 60 120

1 Inch = 62 Miles

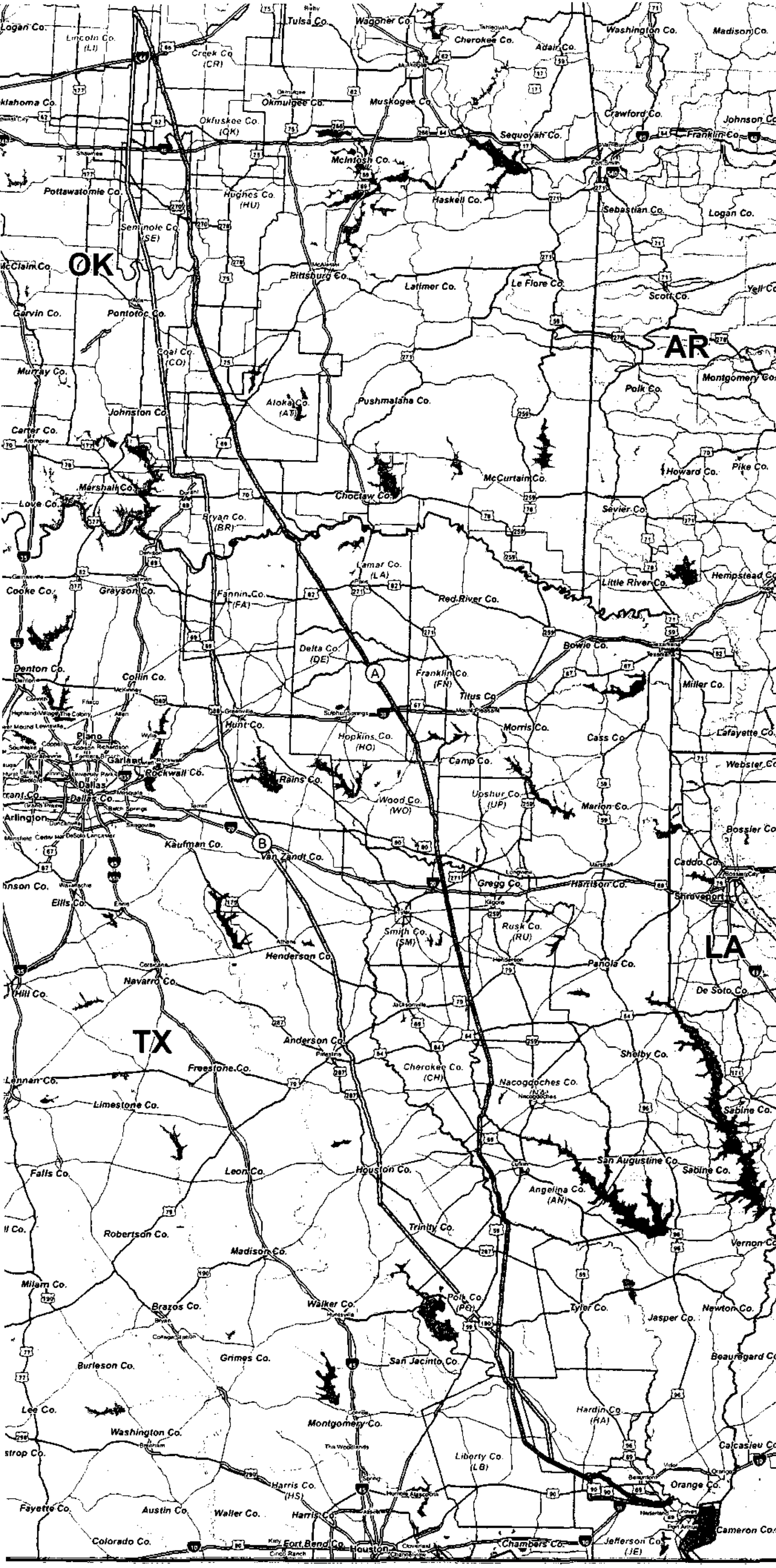
Legend

- Route B (Preferred Route)
- Route A
- Route A1A
- Baker Alternative
- Express-Platte Alternative
- Interstate Highway
- Highway & Major Roads
- Lakes
- Rivers & Streams
- Urban Areas
- National Parks & Forests
- Online County Boundary
- County Boundary
- State Boundary

ConocoPhillips

Figure 2.4.2
Steele City Segment Alternatives

Scale:	Date:	
1" = 62 Mi	July 6, 2009	
App. By: RG	Dwn. By: GS	Sheet: 2 OF 4



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KEYSTONE XL PROJECT GULF COAST SEGMENT

N

W E

S

0 12.5 25 50

1 Inch = 26 Miles

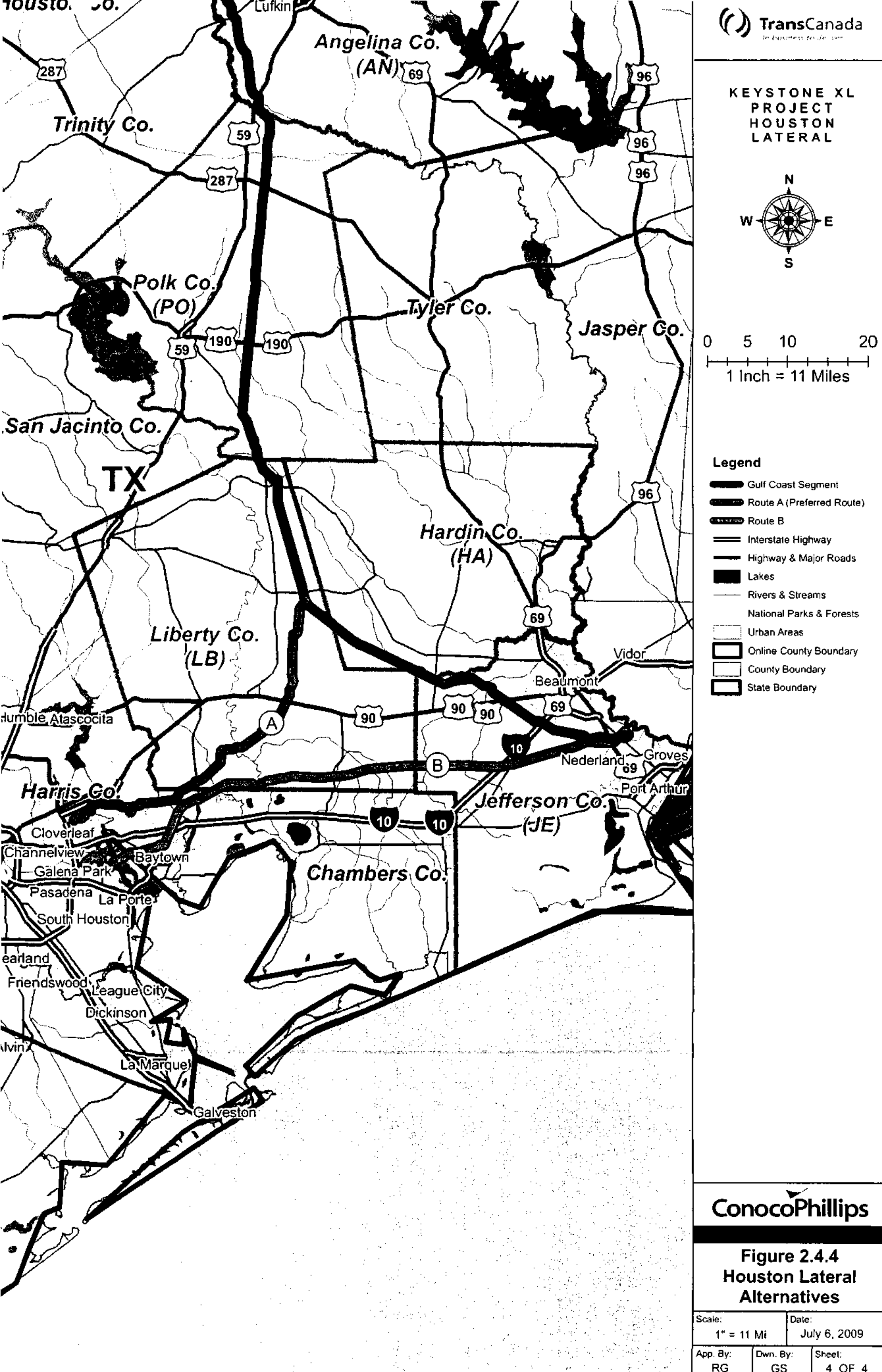
Legend

- Route A (Preferred Route)
- Route B
- Interstate Highway
- Highway & Major Roads
- Lakes
- Rivers & Streams
- National Parks & Forests
- Urban Areas
- Online County Boundary
- County Boundary
- State Boundary

ConocoPhillips

Figure 2.4.3 Gulf Coast Segment Alternatives

Scale:	Date:	
1" = 26 Mi	July 6, 2009	
App. By: RG	Dwn. By: GS	Sheet: 3 OF 4



TransCanada

KEYSTONE XL PROJECT HOUSTON LATERAL

ConocoPhillips

Figure 2.4.4 Houston Lateral Alternatives

Scale: 1" = 11 Mi	Date: July 6, 2009	
App. By: RG	Dwn. By: GS	Sheet: 4 OF 4

Environmental Constraints

The most significant environmental constraints affecting the routing analysis along the Gulf Coast Segment are national and state forests and parks, wildlife habitats, tribal lands, surface rock outcrops, steep ascent/descent slopes, and HCAs. Some of these are:

- Caddo National Grassland;
- Davy Crockett National Forest;
- Angelina National Forest;
- Sam Houston National Forest;
- Big Thicket National Preserve;
- Piney Woods Mitigation Bank;
- Menard Creek Crossing;
- Texas Correctional Facility;
- Entergy Corridor; and
- Expansive forested wetland complexes along the extreme southern portion of the study area.

Avoidance Areas

Routing assessed and selected alternatives around the following land use categories to the extent practical:

- Indian Reservations, Tribal Lands;
- Other publicly owned lands including, USFWS, State Lands, NPS, USACE, US Department of Defense (USDOD), etc.;
- Urban areas and residences and farmsteads;
- Military bases;
- Rural schools and recreational areas;
- Municipal sewage ponds;
- Industrial facilities (e.g., rail yards, warehouses), except when in industrial corridors;
- Cemeteries;
- Oil/natural gas fields; and
- Well heads and irrigation pivot points.

Co-location Areas

To the extent practicable, alternatives were sited to co-locate with the following existing facilities:

- Existing pipelines;
- Existing railways;
- Various existing roadways; and
- Electrical power lines and other utilities.

2.4.2 Steele City Segment Alternatives

Western Alternative

The Western Alternative would enter the US at Morgan, Montana, and run southwest through Montana, South Dakota, Nebraska, Kansas, and Oklahoma to reach the delivery point at Cushing, Oklahoma. The route would then run south to Nederland and Moore Junction. The total length of this route would be 1,110 miles in the US. This route would cross northeast of Fort Peck Reservoir and avoid crossing reaches of the Niobrara River designated wild and scenic.

Most of the northern portion of the Western Alternative, from the US/Canada border to the delivery point at Cushing, would be constructed within new ROW; only the northernmost portion of the alternative would parallel the existing Northern Border Pipeline. South of Cushing to Nederland and Moore Junction, this alternative route would follow multiple ROWs. New pipeline would be constructed for the entire route. This alternative was not analyzed further because it failed to make use of the Cushing Extension thereby resulting in approximately 300 additional miles of Greenfield pipeline construction.

Express Pipeline Alternative

The Express Pipeline Alternative was developed at the request of the Montana DEQ. This alternative would parallel the existing ROW for the Express and Platte Pipeline Systems from Hardisty, Alberta to Steele City, Nebraska. The Express Pipeline runs south from Hardisty through central Montana and into central Wyoming before turning east and ending near Casper, Wyoming. The Platte Pipeline runs southeast from Casper, Wyoming and east across southern Nebraska before intersecting with the Cushing Extension near Steele City, Nebraska.

Populated and Cultivated Areas

After the Express Pipeline Alternative crosses into Montana, the area is predominately agricultural, which is unique to the region that the pipeline traverses. The pipeline crosses the Milk River and a few drainage features south of Highway 2 before entering Chouteau County, and then crosses the Missouri River immediately west of the designated National Wild and Scenic River and Upper Missouri Breaks National Park. Express then continues into Fergus County and in and out of Judith Basin County where the land use remains agricultural; however, there also are a greater number of densely populated areas. Routing parallel to the Express Pipeline through these areas would impose a more significant impact on the local population than routing through more remote terrain.

Difficult Terrain

The Yellowstone River and its tributaries at the border of Carbon County present difficult terrain features to traverse on both sides of the river. Additionally, the pipeline travels through the Pryor Mountain ranges, which can be difficult for construction and reclamation throughout Carbon County.

Differences in Canadian Routing and Existing Infrastructure

The preferred corridor selection was directly influenced by control points in Canada and the US, and the presence of existing linear infrastructure. Concerns included in this analysis were environmental and social costs, as well as cost of overall infrastructure. Because TransCanada also owns the Foothills Pipeline in Canada, ease of negotiations for adjoining ROW within Canada was also considered. Based on this analysis, as well as overall Project length in Canada and the US, a corridor contiguous with the existing Foothills pipeline was identified as the preferred corridor over a corridor contiguous with the Express Pipeline.

Steele City Segment Route A Alternative

The Steele City Segment Route A Alternative is co-located with an existing and proposed pipeline for the entire pipeline route. This alternative enters the US parallel to the Northern Border Pipeline in Phillips County, Montana, running in a southeasterly direction. The route continues to be co-located with the Northern Border Pipeline crossing through the Fort Peck Indian Reservation and then enters North Dakota through Williams County. The route crosses the Missouri River at the Williams-McKenzie County border and again at the Morton-Emmons County border in North Dakota. The route then crosses into McPherson County, South Dakota, continues in a southeasterly direction and crosses the proposed Keystone Pipeline in the northwestern corner of Clark County, South Dakota. The route turns south, co-locating with the proposed Keystone Pipeline through South Dakota, crossing the Missouri River near Yankton, South Dakota. The route enters Cedar County, Nebraska, continuing to co-locate with the Keystone Pipeline until intersecting with the Platte Pipeline in Jefferson County, Nebraska. The route will then interconnect with the proposed Cushing segment of the Keystone Pipeline Project near Steele City.

Wilderness Study Area - Bitter Creek (MP 44 to MP 48)

Under the Federal Land Policy and Management Act, the BLM conducted studies on several tracts of land with the intention of designating certain parcels as "wilderness study areas (WSAs)." One of these properties is the Bitter Creek WSA, which consists of approximately 59,660 acres of land. The area is known to contain a variety of vegetation types and wildlife habitat in the state of Montana. Currently, the BLM manages the protection of WSAs. The BLM will be the primary agency that will determine the possibility and mitigation involved with crossing this WSA.

Tribal Lands – Fort Peck Indian Reservation (MP 58 to MP 146)

Fort Peck Indian Reservation is under the jurisdiction of the Bureau of Indian Affairs (BIA). Obtaining ROW easements across BIA lands can require significantly more time and processing than private or other federally managed lands and would jeopardize the Project schedule.

Steele City Segment Route A1A Alternative

The Steele City Segment Route A1A Alternative is an additional alternative to the Steele City Segment Route Option A. As in the Steele City Segment Route A Alternative, this alternative co-locates with the Northern Border Pipeline along the east-west portion of the route and with the proposed Keystone Pipeline along the north-south segment except in northeastern Montana where the route runs to the north around the Fort Peck Indian Reservation.

The route also crosses the Bitter Creek WSA, then deviates from the Steele City Segment Route Option A in central Valley County, Montana, by continuing to run east just to the north of the Fort Peck Indian Reservation. The route then turns south at the eastern edge of the reservation in Sheridan County, Montana, and runs to the west of the Medicine Lake area through an area identified post-reconnaissance as a wildlife refuge. This area will be discussed later in the report. The route crosses into Roosevelt County, Montana, turning to the southeast and crosses into Williams County, North Dakota. The route joins back with the Steele City Segment Route Option A just north of the Missouri River crossing at the Williams-McKenzie County border in North Dakota and continues to co-locate with the Northern Border Pipeline.

Medicine Lake National Wildlife Refuge (Approximate MP 169)

The Medicine Lake National Wildlife Refuge (NWR) was established in 1935 to provide breeding habitats for migratory birds and other wildlife. The Refuge is managed by the USFWS. It lies within the highly productive prairie pothole region and has relief typical of the glacial drift prairie. Medicine Lake NWR was recognized by the American Bird Conservancy as one of the "Top 100 Globally Important Bird Areas in the US" and was designated as a National Natural Landmark in 1980.

The refuge is home to a diverse array of native prairie and wetland-associated wildlife species. More than 273 species of birds were spotted in the NWR and 125 bird species breed there. The 31,660-acre refuge contains 22 natural and artificial lakes and managed impoundments, along with numerous small wetlands or "potholes" encompassing more than 13,000 wetland acres. NWR uplands consist of gently rolling mixed-grass prairie with a few trees found in riparian areas. The rolling hills and sand dunes around Medicine Lake make up the most extensive sand hill formation in Montana.

NWR grasslands and wetlands are prime breeding areas for waterfowl, with 17 species producing 40,000 offspring annually. It also is an important resting area for migrating birds, including sand hill cranes, Canada geese, white-fronted geese, tundra swans, and many duck species. The American white pelican nesting colony in the refuge is one of the largest in North America, with about 10,000 birds breeding there each summer. Large populations of rare grassland birds such as Baird's sparrows, Sprague's pipits, and chestnut-collared longspurs nest on refuge prairies, attracting birdwatchers from all over the US.

Additionally, some year-round residents include white-tailed and mule deer, coyote, badger, beaver, muskrat, sharp-tailed grouse, and pheasant. Less frequent visitors include moose, elk, and pronghorn. A wolverine was seen in 1998.

The Steele City Route A1A Alternative traverses Diversion Ditch No. 1, a canal that connects the refuge to Big Muddy Creek in Sheridan County, Montana. The field reconnaissance indicates that the ditch is an extension of the refuge, but the surrounding lands are not. The potential impact of this crossing may be minimized or avoided by adjusting the currently proposed alignment, or by using the HDD installation technique across Diversion Ditch No. 1 and/or Lake Creek. Whether or not a pipeline crossing will be allowed at this point is subject to agency discussion and the potential presence of other utility crossings.

Prairie Potholes

Prairie potholes are depressional wetlands (primarily freshwater marshes) often found in the Upper Midwest, especially North Dakota, South Dakota, Wisconsin, and Minnesota, but also in northeastern Montana. This formerly glaciated landscape is pockmarked with an immense number of potholes, which fill with snowmelt and rain in the spring. Some prairie pothole marshes are temporary, while others may be permanent. Here a pattern of rough concentric circles develops. Submerged and floating aquatic plants take over the deeper water in the middle of the pothole while bulrushes and cattails grow closer to shore.

The Upper Midwest is described as being one of the most important wetland regions in the world because of its numerous shallow lakes, marshes, rich soils, and warm summers. The area is home to more than 50 percent of North American migratory waterfowl, with many species dependent on the potholes for breeding and feeding. In addition to supporting waterfowl hunting and birding, prairie potholes also absorb surges of rain, snow melt, and floodwaters, thereby reducing the risk and severity of downstream flooding.

Prairie potholes become more prominent in the eastern portion of the Steele City Route A1A Alternative than other Steele City Segment alternative routes. These wetland types typically increase the construction and mitigation costs of construction.

Steele City Segment Route B (Proposed) Alternative

Steele City Segment Route B Alternative is designed to minimize the miles of newly constructed pipe relative to the Western Alternative by taking advantage of interconnection with existing pipe, as well as providing a shorter route and avoids many of the environmental and regulatory constraints associated with Steele City Alternatives A and A1A. This route option is approximately 851 miles long, and crosses approximately 42 miles of federally managed lands. Steele City Route B Alternative enters the US parallel to the Northern Border Pipeline in Phillips County, Montana, and is co-located with that existing ROW for approximately 21.5 miles within the first 25 miles of the Project.

After Route B diverges from the Northern Border Pipeline, it continues in a more southerly direction to the west of the Fort Peck Indian Reservation, crossing the Missouri River through the narrow gap between the Fort Peck Reservoir and the Fort Peck Indian Reservation. The route then proceeds southeast, crossing into Harding County, South Dakota, and continues in a southeasterly direction to enter Nebraska in Keya Paha County. There it crosses the Niobrara River east of the segment designated as wild and scenic. The route continues southeast, to parallel a short portion of the Keystone Pipeline ROW in the southern portion of Jefferson County. The route then interconnects with the proposed Cushing Extension segment of the Keystone Pipeline Project near Steele City.

Department of Defense Property (Approximate MP 87.3)

The DOD is the underlying owner of a parcel of land on the south and southeastern side of the Missouri River near the confluence with the Milk River. It is a parcel of land that cannot be avoided because the Charles M. Russell NWR lies to the west-southwest and the Fort Peck Indian Reservation lies to the northeast of the proposed crossing. Land in this area appears to be open rangeland with trees and shrubs interspersed on the property. The manager of the land appears to be the BLM.

A crossing of this property will require an easement from the USACE.. Because this pipeline will be greater than 24 inches in diameter, Congressional notification will be required. At this time, based on high-level, non-Project specific discussions, it appears granting an easement for the pipeline will be possible.

Steele City Segment Route B with Baker Alternative

The Steele City Segment Route B with Baker Alternative was developed at the request of the Montana DEQ. This alternative includes a 63-mile deviation from Steele City Segment Route B as described previously, paralleling an existing pipeline right-of-way around Baker, Montana, through southwest North Dakota, and rejoining Steele City Segment Route B in northeastern South Dakota.

Water Supplies

The Baker Alternative will route the pipeline through the municipal watershed for the City of Baker, Montana, and potentially will impact Baker Lake.

Constructability

Southeast of Baker, the Baker Alternative crosses an existing oil and gas field, with associated roads, underground gathering lines, and power lines. Special crossing techniques, including HDD will be required. These techniques will offset potential cost savings associated with reducing pipeline length, would increase the potential for damage or injury to workers and the public due to the proximity to wells and underground gathering lines, could potentially interrupt collection of product from the existing wells, and would temporarily interrupt access to those wells where access roads are crossed.

Permitting Issues

The Steele City Segment Route B with Baker Alternative will route the pipeline through North Dakota, which will require additional permitting that could jeopardize the Project schedule.

Table 2.4-1 summarizes the lengths of the alternatives considered for the northern portion of the Project.

Table 2.4-1 Lengths of the Steele City Segment Route Options (Canadian Border to Cushing, Oklahoma)

Steele City Route Alternative	Route and the Corresponding Alternative	Mileage (New Pipe Construction)	Mileage (Connection to Keystone Cushing Extension)
Western Alternative	Western Alternative – direct line to Cushing, Oklahoma	1,110	0
Express Pipeline Alternative	Following the Express Pipeline from Hardisty, Alberta, Canada to Steele City, Nebraska	1,061	298
Route A	Eastern route through Montana, North Dakota, South Dakota, and Nebraska, to connect to the Keystone Cushing Extension at Steele City	920	298
Route A1A	Eastern route through Montana, North Dakota, South Dakota, and Nebraska, to connect to the Keystone Cushing Extension at Steele City, avoiding BIA lands	951	298
Route B	Eastern route through Montana, South Dakota, and Nebraska, to connect to the Keystone Cushing Extension at Steele City	851	298
Route B with Baker Alt	Follow Route B, except at Baker, Montana, to follow an existing pipeline through southwestern North Dakota, to rejoin Alternative B in South Dakota	851	298

2.4.3 Gulf Coast Segment

The analysis of Gulf Coast Segment initially included two primary routes and four secondary routes. Based on the control points and opportunities identified for the Project, the routing alternatives concentrated on the most direct route resulting in the alternative considered being routed through Oklahoma and Texas.

<u>Oklahoma</u>

In Oklahoma, the Project start point commences east of Oklahoma City. The Oklahoma area consists of gently rolling topography with east facing escarpments and isolated buttes continuing into southern Oklahoma and gently rolling topography to relatively flat topography with limestone.

The Project area contains several geological faults in Oklahoma (preferred route locations – crossing fault zone at MP 39.5 to MP 41, parallel to fault at MP 48.5 to MP 49.5 and crossing fault zone at MP 86.5 to MP 106.5).

The Project area transverses a zone of increased seismic risk in southern Oklahoma and damage resulting from seismic activity in this zone is expected to be moderate.

Agriculture is a significant land use, with the primary croplands being wheat and forage/hay. Some oat and corn fields are crossed in Oklahoma.

Based on preliminary analysis, the Project crosses improved pasturelands and hayfields with some locations crossed considered tall grass prairie areas.

Route options cross several large rivers along with several large creeks in Oklahoma before crossing into Texas.

The timberland that is crossed in Oklahoma has low commercial value.

Some urban residential impact could occur near towns such as Stroud, Holdenville, and Centrahoma in Oklahoma.

The main crops encountered will be forage or hay, improved pastures, timber, rice and soybeans. Wheat, sod farms, and poultry farms also will be crossed. There are few, if any, landowners participating in the Conservation Reserve Program along the route in Oklahoma.

The majority of lands crossed in Oklahoma are privately owned; and less than one percent of lands crossed are owned by the state or federal government in Oklahoma.

Texas

In Texas, the Project start point commences east of Dallas - Fort Worth. The Project area in Texas consists of gently rolling topography, sand hills, black prairie, and pine barrens to flat-lying coastal prairie. There are occurrences of shallow rock in selected areas (preferred route locations – MP 154 to MP 200, MP 200 to MP 369, and MP 405 to MP 475). These shallow rock areas typically encountered are fragmented and no blasting is anticipated. No special problems are expected with excavation and there may be conditions in localized areas requiring more specialized equipment (blasting, jackhammers, or saws).

In Texas, the Project area contains several geological faults (preferred route locations – Crossing Fault Zone at MP 189 to MP 207, crossing fault zone at MP 296 to MP 308).

The Project area in northeast Texas crosses a zone where minor seismic risk exists and the remainder of east Texas and the Gulf Coast is described as having no seismic risk.

Rice and soybean fields are more prevalent in Texas, with some areas that use flood-and center pivot irrigation.

Based on preliminary analysis, the Project crosses improved pasturelands and hayfields.

Texas route options cross several additional large rivers and several large creeks.

Towns like Tyler/Longview, Lufkin, and the cities of Beaumont/Port Arthur, and Houston were avoided by routing around them.

The main crops encountered will be forage or hay, improved pastures, timber, rice and soybeans with some areas that use flood- and center pivot irrigation. Wheat, sod farms, and poultry farms will also be crossed. There are few, if any, landowners participating in the Conservation Reserve Program (CRP) along the route in Texas. The majority of lands crossed in Texas are privately owned. Less than one percent of lands crossed are owned by the state government in Texas (Deep Fork Wildlife Management Area and the San Jacinto State Battleground).

The proposed Project route will cross the Piney Woods Mitigation Bank (PWMB) at approximate MP 366 to MP 371. The PWMB was established in December 2008 and is the largest mitigation bank in Texas. The PWMB is a privately owned wetlands mitigation bank that has been permitted by the USACE. The PWMB meets the criteria for Mitigation Banks under Federal Guidance for the establishment, use, and operation of mitigation banks and the laws of the State of Texas. The bank was approved following review by an Interagency Review Team, comprised of the USACE, USEPA, USFWS, TPWD, TCEQ, GLO, and the Railroad Commission of Texas.

Gulf Coast Segment Alternatives Descriptions

Two major route options, Gulf Coast Segment Route Options A and B, were analyzed between facilities in Cushing, Oklahoma, and proposed facilities in Nederland, Texas.

Several shorter segments for the Gulf Coast Segment from Nederland were reviewed to determine which would provide the most practical connection to the Houston Ship Channel. An existing 20-inch ARCO products line was considered. A portion of this line could be acquired and utilized as a secondary means of reaching the Houston Ship Channel.

Gulf Coast Segment Route Alternative A

Gulf Coast Segment Route Alternative A was the initial route identified because it follows an existing 30-inch diameter natural gas pipeline corridor (Texoma) from Cushing to Nederland. Portions of the Texoma line have been sold and are operated by various companies; however the corridor is still intact. This route is the shorter between Cushing and Nederland at approximately 456 miles.

Gulf Coast Segment Route Alternative A was adjusted during feasibility analysis to the west to avoid the developed, urban area and cities associated with Longview, Tyler, and Nacogdoches, Texas, and the Angelina National Forest. Attention also was given to oil and gas activity and abandoned fields.

This route is co-located with four other utility corridors (pipeline and electric transmission) and can be summarized as approximately 93.5 percent co-located with other utility ROWs. This route is approximately 394.9 miles, or 86.6 percent, co-located with existing pipelines and approximately 31.3 miles, or 6.9 percent, co-located with power lines.

There are two greenfield areas approximately 29.8 miles, or 6.5 percent, not co-located, allowing the avoidance of communities of Longview, Tyler, and Nacogdoches, Texas, and the Angelina National Forest.

Alternative A crosses approximately 21 major roads, 485 minor roads, 104 major streams/waterbodies, 131 minor streams/waterbodies, 16 railroads, 49 power lines, 40 pipelines (data is from Pennwell database).

Alternative A is in a less urban area which implies potentially easier construction, fewer landowner issues, and less organized resistance to the pipeline.

Gulf Coast Segment Route Alternative B

Gulf Coast Segment Alternative B is the secondary alternative considered that would connect facilities in Cushing, Oklahoma with facilities in Nederland, Texas. Alternative B is longer between Cushing and Nederland at approximately 486 miles. Alternative B is west of Alternative C and therefore passes closer to Dallas-Ft. Worth metropolitan area. A portion of Alternative B is co-located with the Seaway Pipeline for approximately 190 miles south of Cushing, Oklahoma and was adjusted to avoid Lake Texoma and remain east of Durant, Oklahoma.

Alternative B is co-located with 10 pipeline ROWs and 1 power line, resulting in approximately 97.8 percent co-location with other utility ROWs. Specifically, Alternative B is approximately 458.3 miles, or 94.3 percent, co-located with existing pipelines and approximately 17 miles, or 3.5 percent, co-located with power lines.

There is one greenfield segment, approximately 10.7 miles, or 2.2 percent, not co-located, which is necessary to avoid development and congestion.

Alternative B consists of 24 major roads, 559 minor roads, 94 major streams/waterbodies, 154 minor streams/waterbodies, 24 railroads, 63 power lines and 72 pipelines (data is based on Pennwell information).

Alternative B does involve a potential crossing of the Big Thicket Natural Preserve, a NPS-owned park.

Gulf Coast Segment Route Alternative A and B Comparison

Alternative B crosses less wetland areas than Alternative Option A. Thus constructability might be more favorable and there would be less regulatory obstacles. Conversely, Alternative B would pass closer to the Dallas area, implying greater land costs and potentially organized resistance to the pipeline.

Issues associated with Alternative A included extensive timbered wetlands and overall wetland areas on the southern portion of the route. The southern portion of Alternative B encounters fewer timbered wetlands and fewer wetlands.

The majority of lands crossed by the Alternative A are privately owned. Less than one percent of lands are owned by either the State of Oklahoma or State of Texas.

Gulf Coast Segment Conclusion and Selected Alternative

A combination of Gulf Coast Segment Route Alternatives A and B, with some detailed routing, was determined to provide the most sensible alternative to connect Cushing and Nederland. The combined Gulf Coast Segment Alternatives A and B is now designated as the preferred route alternative for the Gulf Coast Segment and was subsequently surveyed for this Environmental Report.

The preferred route incorporates the advantages of the northern two-thirds of Gulf Coast Segment Alternative A and the southern one-third of Gulf Coast Segment Route Alternative B. The less urban construction to north coupled with the less timbered wetlands to the south should provide the most cost-effective route. The preferred route is 480 miles in length and specifically, consists of 417 miles, or 87 percent, co-located with other ROWs, including 14 different pipelines, power lines, and 1 electric transmission corridor.

Paralleling the Old Texoma Pipeline in the state of Oklahoma and North Texas should benefit the Project. Co-location is generally viewed favorably by landowners. It requires less clearing when crossing timbered tracts. Landowners generally prefer utility easements be in one place on their property.

The Big Thicket National Preserve and associated wetland complexes as previously noted are considered as an environmental constraint for the preferred but were avoided by placing the pipeline into the Texas highway ROW via an HDD.

The preferred route potentially requires no break out tanks from a design standpoint and traverses approximately 35.3 miles of wetland along the entire route from Cushing, Oklahoma to Nederland, Texas.

The preferred route traverses a number of active and inactive oil and gas fields and there may be historical recorded or unrecorded occurrences of contamination, along the initial 100 miles, south of Cushing, Oklahoma. These issues occur less frequently along the remainder of the route to Nederland, Texas.

2.4.3.1 Houston Lateral Alternatives

Houston Lateral Route Alternative A

Houston Lateral Route Alternative A was initially developed as a lateral from the Gulf Coast Segment Route Alternative B to get to the Houston Ship Channel. Alternative A was then refined to facilitate all Gulf Coast alternatives analyzed and resulted in an approximately 75 mile route to the Houston Ship Channel.

Houston Lateral Route Alternative A is co-located with other utilities that consist of 72.7 miles, 96.9 percent, co-located with other utilities (5 pipelines and multiple pipeline/electric transmission corridors). The remaining 2.3 miles, 3.1 percent, would be routed along an existing roadway and railway.

This route consists of 3 major roads, 74 minor roads, 10 major streams/waterbodies, 20 minor streams/waterbodies, 5 railroads, 15 power lines and 89 pipelines.

Houston Lateral Route Alternative A is described as typical pipeline construction; however, the route encounters very heavy congestion on the southwest end. Utilizing this alternative would more than likely necessitate the construction of break out tanks.

Houston Lateral Route Alternative B

Houston Lateral Route Alternative B is described as a southern alternative to reach the Houston Ship Channel and is approximately 77 miles in length. This alternative is 97 percent co-located with other utilities (6 pipeline and 1 combined pipeline and electric transmission corridor) approximately 72.2 miles and the final 2.3 miles, 3 percent, would be routed alongside a roadway and railway.

Houston Lateral Route Alternative B consists of 3 major roads, 91 minor roads, 25 major streams/waterbodies, 20 minor streams/waterbodies, 7 railroads, 158 power lines and 236 pipelines.

Houston Lateral Route Alternative B follows an existing pipeline corridor and would encounter heavy congestion on the beginning and end of the route. This Alternative would involve typical pipeline construction for a majority of the route and no break out tanks would be required. Alternative B would very likely encounter significant regulatory scrutiny based on the potential impacts associated with the coast (Coastal Zone Management) and heavy concentration of wetlands (USACE and Texas Parks and Wildlife Department [TPWD]).

Houston Lateral Preferred Alternative

The preferred Houston Lateral is a combination of the two alternatives discussed above and is approximately 48.6 miles in length and is 45 percent co-located with other ROWs. The preferred Houston Lateral route has several greenfield areas, which total approximately 26.6 miles, in various lengths along the route and consists of 2 major roads, 33 minor roads, 3 major streams/waterbodies, 49 minor streams/waterbodies, 4 railroads, 2 power lines and numerous pipelines.

The preferred route follows existing utility corridors, especially on the western end which aids in routing the pipeline through the areas of heavier population. The route parallels existing pipelines across predominately rice fields and pastures. Due to the high concentration of development, industrial, residential, and commercial, in the Houston Ship Channel area, a corridor system has been developed to accommodate the installation of pipelines and other utilities.