APPENDIX B

Potential Releases and Pipeline Safety

POTENTIAL RELEASES AND PIPELINE SAFETY

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ACRONYMS AND ABBREVIATIONS

AC	alternating current
ACVG	alternating current voltage gradient
API	American Petroleum Institute
ASME	American Society of Mechanical Engineers
ASTM	American Society of Testing and Materials
AUT	automated ultrasonic testing
BS&W	basic sediment and water
C	Celsius
CE	carbon equivalent
C-FER	Reliability Based Prevention of Mechanical Damage to Pipelines
CFR	Code of Federal Regulations
CIS	close interval survey
CP	cathodic protection
CPM	continuous pipeline monitoring
CPSs	contributory pipeline segments
CRM	control room management
CSA	Canadian Standards Association
dBμV	decibel-microvolts
DCVG	direct current voltage gradient
EIS	Environmental Impact Statement
ERP	Emergency Response Plan
ES	Executive Summary
ESA	Endangered species Act
F	Fahrenheit
FBE	fusion bond epoxy
FEIS	Final Environmental Impact Statement
FRP	Facility Response Plan
FPR	failure pressure ratio
HCA	High-Consequence Area
IIW	International Institute of Welding
ILI	in-line inspection
IMP	Integrity Management Plan
IR	current (I) flowing through a resistance (R)
LDS	leak detection system
LP	Limited Partnership
MDEQ	Montana Department of Environmental Quality
MFL	magnetic flux leakage
MFSA	Major Facilities Siting Act
MLV	mainline valve
MOP	maximum operating pressure
NACE	National Association of Corrosion Engineers
NDE	nondestructive examination
NDEQ	Nebraska Department of Environmental Quality
NTSB	National Transportation Safety Board
PAH	polycyclic aromatic hydrocarbon
PHMSA	Pipeline and Hazardous Material Safety Administration
PSL	product specification level
RBWMD	Rainwater Basin Wildlife Management District
RFI	request for information
ROW	right-of way
RP	Recommended Practice
R-STRENG	remaining strength
SCADA	Supervisory Control and Data Acquisition
SMYS	specified minimum yield strength
SME	subject matter experts
SOP	standard operating procedures
SRP	spill response plan
T&E	threatened and endangered
TPD	Third Party Damage
TPIC	Third Party Inspection Company
USFWS	U.S. Fish and Wildlife Service
USGS	U.S. Geological Survey
UT	ultrasonic test
V	volt

1.0 INTRODUCTION

This appendix includes those measures that Keystone has committed to implementing for the proposed Keystone XL Project, including:

- Special Conditions recommended by PHMSA;
- Mitigation measures recommended in the Battelle and E^{x}ponent risk reports; and
- Additional mitigation measures.

2.0 SPECIAL CONDITIONS RECOMMENDED BY PHMSA

Table 1 presents Special Conditions that PHMSA recommended, a comparison to requirements in 49 CFR 195, and benefits of the proposed conditions.

Table 1 Special Conditions Recommended by PHMSA

Condition	Keystone XL[1]	49 CFR 195	Benefits
1	**Steel Properties:** Skelp/plate must be micro-alloyed, fine grained, fully killed steel with calcium treatment and continuous casting.	Less prescriptive; references American Petroleum Institute (API) 5L standard, which does not require latest steel making properties.	These properties help ensure high quality carbon steel which may reduce the chance of a pipeline release.
2	**Manufacturing Standards:** Pipe must be manufactured according to American Petroleum Institute Specification 5L, Specification for Line Pipe (API 5L 44th Edition), product specification level 2 (PSL 2), supplementary requirements 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, carbon equivalent (CE) (Pcm) formula (Ito-Bessyo formula), or 0.40 percent based on the C-IIW formula (International Institute of Welding formula).	Less prescriptive; references API 5L standard.	Help ensure the steel is weldable when the pipe joints are joined together in the field using manual and mechanized welding processes based on the various alloys used to make up the chemical nature of the high strength carbon steel.
3	**Fracture Control**: API 5L and other specifications and standards addressing the steel pipe toughness properties needed to resist crack initiation and crack propagation, and to ensure crack arrest during a pipeline failure caused by a fracture must be followed. Keystone must prepare and implement a fracture control plan addressing the steel pipe properties necessary to resist crack initiation and crack 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 must be in accordance with API 5L (44th Edition) and include the following tests: a) Fracture Toughness Testing for Shear Area: Test results must indicate at least 85 percent minimum average shear area per test for all X-70 heats	Less prescriptive; references API 5L standard.	Helps ensure that the pipe is resistant to initiation of and propagation of a flaw and that, if a failure does occur, the steel has adequate properties so that the pipe will not have a running fracture over multiple joints of pipe.

[1] PHMSA recommends that the State Department require TransCanada Keystone Pipeline, LP (Keystone) to include the Special Conditions in its written design, construction, and operating and maintenance plans and procedures.

Condition	Keystone XL[1]	49 CFR 195	Benefits
	and 85 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 and arrest; b) Fracture Toughness Testing for Absorbed Energy in accordance with Annex G and a minimum of 50 ft-lb per heat on a full sized specimen at -5 degrees C/23 degrees F; and c) Fracture Toughness Testing by Drop Weight Tear Test for All New Pipeline Segments or Pipe Replacements: Test results must be at least 85 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 and arrest. The above fracture control 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 shut-in conditions. Where the use of stress factors, pipe grade, operating temperatures, and product composition make fracture toughness calculations non-conservative, correction factors must be used.		
4	**Steel – Plate, Coil, or Skelp Quality Control and Assurance:** Keystone must prepare and implement an internal quality management program at mills involved in producing steel plate, coil, skelp, and pipe to be operated in the pipeline. These programs must be structured to detect and eliminate defects, inclusions, non-specification yield strength, and tensile strength properties, and chemistry affecting pipe quality. A mill inspection program or internal quality management program must include the following: a) Non-destructive test of the ends and at least 35 percent of the surface of the plate, coil, or pipe must be performed to identify imperfections such as laminations, cracks, and inclusions that may impair serviceability; 100 percent of the pipe sections must be tested. Surface ultrasonic must be done in accordance with American Society of Testing and Materials (ASTM) A578/A578M Level B or equivalent, to acceptance Level B. Pipe ends must be inspected by ultrasonic, magnetic particle or liquid penetrant methods, with acceptance criteria as outlined in Clause 9.10.4 or API 5L (44th Edition). b) A macro etch test or other equivalent method must be performed to identify inclusions that may form centerline segregation during the	General, less prescriptive in Code Section 195.112 and references API 5L.	These properties help ensure high quality carbon steel.

Condition	Keystone XL[1]	49 CFR 195	Benefits
	continuous casting process. Use of sulfur prints is not an equivalent method. The test must be carried out on a slab from the first heat of each sequence, and graded with an acceptance criteria of one or two on the Mannesmann scale or equivalent; c) A quality assurance monitoring program implemented by the operator must include evaluations of: i. All steelmaking and casting facilities; ii. Quality control plans and manufacturing procedure specifications; iii. Equipment maintenance and records of conformance; iv. Procedures for controls on superheat and casting speeds, steel rolling temperatures and cooling temperatures; v. Additional mechanical and chemical properties tests based on steel grade, plate, or coil, and must be selected based on knowledge of patterns of property variability in the coils and plate based on the steel making process and rolling and cooling temperatures to assure that steel properties are not variable; vi. A verification program to ensure the pipe mill is taking into account all yield and tensile strength losses that may occur in the coiling and pipe rolling processes to ensure that the finished pipe has yield and tensile strengths that meet API 5L specifications; vii. Coils and plate with casting and rolling process deviations that may affect steel properties must have a re-verification of mechanical and chemical properties on the pipe heat conducted at pipe location to ensure there is no variability in the pipe; viii. The pipe supplier must notify Keystone of all instances that do not meet the above items before supplying the pipe to Keystone; and ix. Procedures for centerline segregation monitoring to ensure mitigation of centerline segregation during the continuous casting process. d) Pipe end tolerances must be applied so that there are no flat spots on the pipe that could affect welding quality. From each pipe mill, the end tolerances on pipe diameter must not exceed the range given in API 5L, Forty-Fourth (44th) Edition, Table 10, for any given pipe wall thickness. Keystone must demonstrate compliance with API 5L 44th Edition, Table 10 by providing to the appropriate Pipeline and Hazardous Materials Safety Administration (PHMSA) Region Director(s), Central, Western, and Southwest Region, a histogram of end tolerance and wall thickness data representing physical evidence of		

Condition	Keystone XL[1]	49 CFR 195	Benefits
	compliance for a minimum of 10 percent of the pipe manufactured by each pipe mill facility. e) During construction, if pipe supplied from varying pipe mills cannot be preferentially strung, histograms and field weldability tests should be conducted to ensure that excessive high low is not in production or field welds.		
5	**Pipe Seam Quality Control**: Keystone must prepare and implement a quality assurance program for pipe weld seams. The pipe weld seam tests must meet the minimum requirements for tensile strength in API 5L 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 3 readings for each heat affected zone, 3 readings in the weld metal and 2 readings in each section of pipe base metal for a total of 13 readings. The pipe weld seam must be 100 percent ultrasonic tested (UT) inspected after expansion and hydrostatic testing per APL 5L.	General, less prescriptive in Code Section 195.112 and references API 5L.	These properties help ensure that welded seams (helical and straight) are an equivalent or stronger strength to the pipe.
6	**Monitoring for Seam Fatigue from Transportation:** Keystone must inspect the double submerged arc welded seams of the delivered pipe using properly calibrated manual or automatic ultrasonic testing techniques. For each lay down area, 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. For longitudinal weld seams, the entire seam must be tested. For helical seam submerged arc welded pipe, the weld seam in the area along the transportation bearing surfaces and all other exposed welded areas during the test must be tested. All the results must be appropriately documented. Each pipe section test record must be traceable to the pipe section tested.	General, less prescriptive in Code Sections 195.200 and 195.204.	This condition may result from a National Transportation Safety Board (NTSB) failure analysis finding from a historical pipeline failure. This spot-check—post-rail transportation to site—is an added check that no damage is present on pipe after rail transport.
7	**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 Pipelines* calculation method.	General, less prescriptive; no defined requirement.	Additional steel properties to resist external mechanical damage, the most common cause of pipeline failure.

Condition	Keystone XL[1]	49 CFR 195	Benefits
8	**Mill Hydrostatic Test:** The pipe must be subjected to a mill hydrostatic test pressure of 95 percent specified minimum yield strength (SMYS) or greater for 10 seconds. The 95 percent stress level may be achieved using a combination of internal test pressure and the application of end loads imposed by the hydrostatic testing equipment as allowed by API 5L, Clause 10.2.6.6.	Sections 195.3 and 195.112.	Validates mainline pipe and seam integrity in the plant prior to final hydrotest in field.
9	**Pipe Coating:** The application of a corrosion-resistant coating to the steel pipe must be performed according 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. All pipe must be protected against external corrosion by non-shielding: coatings, repair coatings, and protective material used to protect the pipe from rock damage. Holiday detection must include appropriate calibration of jeeping equipment on a holiday that extends through the coating to the metal of the pipe to be jeeped prior to use each working day. Jeeping voltages must be set at a minimum of 2,500 volts (V) for fusion bond epoxy (FBE), with higher voltages to be considered based on the coating type, thickness (maximum and minimum), grounding, and field conditions that day. For other coatings, minimum voltage settings need to be established by determining the nominal coating thicknesses and coating type. The pipe should be free of any excess debris prior to running the jeeping equipment over the area. Visual inspection for holidays and coating damage should complement the use of jeeping equipment. All pipe coating must be checked with holiday detection equipment prior to backfill and FBE-coated pipe must be checked with holiday detection equipment set at a minimum of 2500V prior to backfill. All coating defects must be repaired and rechecked prior to backfill. To the extent practical, Keystone must jeep the coating at the same voltage in the coating mill as in the field.	Less prescriptive, Code Section 195.004 requires inspection.	Detailed application process requirements help to ensure quality control of coating process.
10	**Field Coating:** Keystone must implement field girth weld joint coating application specification and quality standards to ensure pipe surface cleanliness, application temperature control, adhesion quality, cathodic disbondment, moisture permeation, bending, minimum coating thickness, holiday detection, and repair quality. Field joint coatings must be non-shielding to cathodic protection (CP). Field coating applicators must use valid qualified coating procedures and be trained to use these procedures.	Less prescriptive; Code Section 195.204 requires inspection, does not require level of specificity.	Helps ensure that personnel are trained and aware of the requirements when applying field joint corrosion protection.

Condition	Keystone XL[1]	49 CFR 195	Benefits
	Holiday detection must include appropriate calibration of jeeping equipment on a holiday that extends through the coating to the metal of the pipe to be jeeped prior to use each working day. Jeeping voltages must be set at a minimum of 2,500V for FBE, with higher voltages to be considered based on the grounding and field conditions that day. For other coatings such as for girth weld coatings, minimum voltage settings need to be established by determining the nominal coating thicknesses (maximum and minimum) and type of coating used for application. The pipe should be free of any excess debris prior to running the jeeping equipment over the area. Visual inspection for holidays and coating damage should complement the use of jeeping equipment.		
11	**Coatings for Trenchless Installation:** Coatings used for directional bore, slick bore, and other trenchless installation methods must be capable of resisting abrasion and other damage that may occur due to rocks and other obstructions encountered in this installation technique.	Less prescriptive, Code Section 195.202 and 195.246 require specification, does not require level of specificity.	Helps ensure that corrosion protection coating is not damaged during installation using trenchless methods.
12	**Bends Quality:** Keystone must obtain and retain certification records of factory induction bends and factory weld bends. 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 0.42 on the CE-IIW formula.	Less prescriptive, Code Section 195.118 requires specifications, does not require level of specificity.	Helps ensure that pipeline materials are traceable for the life of the pipeline and weldable.
13	**Fittings:** Pressure-rated fittings and components (including flanges, valves, gaskets, pressure vessels, and pumps) must be rated for a pressure rating commensurate with the pipeline's maximum operating pressure (MOP).	Less prescriptive, Code Section 195.118 requires specifications, does not require level of specificity.	Helps ensure that correct components are used that match the pipeline design pressure.
14	**Pipeline Design Factor – Pipelines:** Pipe installed must comply with the 0.72 design factor in 49 CFR 195.106. a) At least 6 months before starting the Keystone XL pipeline construction, Keystone must review with the appropriate PHMSA Regional Directors in Central, Western, and Southwest Regions how High Consequence Areas (HCAs) which could be affected, as defined in 49 CFR 195.450 (commercial navigable waterways, high population areas, other populated areas, and unusually sensitive areas including aquifers as defined in 49 CFR 195.6), were determined, and the pipeline design associated with those segments. Keystone must identify piping and the design of piping within pump stations, mainline valve assemblies, pigging facilities, measurement facilities, road crossings, railroad crossings, and segments operating immediately downstream	Less prescriptive, Code Section 195.106 requires 0.72 design factor, does not specify timing for review prior to and post-construction. Code Section 195.452 has additional requirements for pipeline integrity management in HCAs.	Provides regulatory oversight of design compliance to federal codes and standards and helps ensure that encroachments near the pipeline such as urban development or new wellhead protection areas are factored into integrity management plans.

Condition	Keystone XL[1]	49 CFR 195	Benefits
	and at lower elevations than a pump station. Keystone must also provide an overland spread analyses in accordance with Section 195.452(f) to support could-affect determinations for water bodies more than 100 feet wide from high-water mark to high-water mark. b) Post-construction, Keystone must conduct a yearly survey, not to exceed 15 months, to identify changes on the pipeline system that would affect its designation or design.		
15	**Temperature Control:** Normal pump discharge temperatures should remain at or below 120 degrees Fahrenheit (°F). If the temperature exceeds 120°F, Keystone must prepare and implement a coating monitoring program in these areas, using ongoing direct current voltage gradient (DCVG) surveys or alternating current voltage gradient (ACVG) surveys, or other testing to demonstrate the coating integrity. Non-continuous discharge temperature spikes above 120°F for less than ½-day duration will not be a cause for implementing the procedure, but Keystone must inform the appropriate PHMSA Regional Director if regular operation above 120°F at pump station discharges will occur. Under no circumstances may the pump station discharge temperatures exceed 150°F without sufficient justification that Keystone's long-term operating tests show that the pipe coating will withstand the higher operating temperature for long-term operations, and approval from the appropriate PHMSA region(s). Pump Station Discharge Temperature – operating above 120°F and up to 150°F maximum, FBE coating: a) Keystone must monitor coating performance in areas where operating temperatures have exceeded or will exceed 120°F to provide additional data on the long-term durability and integrity of FBE coatings at these temperatures. Cathodic protection current requirements and coating surveys with DCVG (soil cover) and ACVG (pavement cover) will indicate if there is deterioration in the coating at the higher temperatures. b) The DCVG and ACVG coating evaluation survey results will be addressed as follows: The threshold survey indication values are 35 percent IR[2] for DCVG and 50 decibel-microvolts (dBμV) for ACVG. These values represent the mid-range of the *Minor* category in the	General, less prescriptive in Code Sections 195.400, 195.401, 195.402, 195.559, and 195.561.	Helps provide protective measures are in place for corrosion coating protection.

[2] IR = current (I) flowing through a resistance (R)

Condition	Keystone XL[1]	49 CFR 195	Benefits
	severity classification used to characterize survey indications in an External Corrosion Direct Assessment program. c) Keystone must excavate and remediate all indications found above the threshold values: Minor, Moderate, and Severe categories. d) Keystone must conduct a calibration dig on at least two anomalies of each classification that are classified as Minor, Moderate, and Severe to ensure that findings not in the remediation plan are not detrimental to the pipeline. e) Keystone must perform Holiday voltage tests (jeep), coating adhesion, and coating cure tests at excavations. f) Keystone must remove disbonded or blistered coating (with cracking and other damage that will compromise cathodic protection) found during excavations and must apply new coating. g) Keystone must perform baseline DCVG 2½ years and 5 years after operating above 120°F, and in concert with future in-line inspection (ILI) and close-interval (CIS) surveys, both initial and second ILI tool runs, not to exceed 90 days before or past the schedule interval. h) Keystone must monitor surface temperatures of the pipe during winter and summer operating conditions at '0' miles and at a downstream mileage to assure that the surface temperatures do not exceed 120°F. If it is determined that the temperature at this point exceeds 120°F, the survey distance will be increased to the point where the temperature is below 120°F. Keystone must survey based on temperature measurements or a minimum of 20 miles downstream of each pump station operating above 120°F. i) Keystone must make repairs to FBE coatings with a compatible coating system that will bond together, be resistant to soil stresses, and not shield cathodic protection.		
16	**Overpressure Protection Control:** Keystone must limit mainline pipeline overpressure protection to a maximum of 110 percent MOP during surge events consistent with 49 CFR 195.406(b). Before commencing operation, Keystone must perform a surge analysis showing how the pipeline will be operated to be consistent with these overpressure protection conditions. Keystone must equip the pipeline with field devices to prevent overpressure conditions. Remotely actuated valves should be fitted with devices that will stop the transit (intentional or uncommanded) of the mainline valve should an overpressure condition occur or an impending overpressure condition is	Required in Section 195.406(b), but less prescriptive on surge analysis.	Helps provide additional assurance that overpressure protection measures are in place.

Condition	Keystone XL[1]	49 CFR 195	Benefits
	expected. Sufficient pressure sensors, on both the upstream and downside side of valves, must be installed to ensure that an overpressure situation does not occur. Sufficient pressure sensors must be installed along the pipeline to conduct real time hydraulic modeling, which can be used to conduct a surge analysis to determine whether pipeline segments have experienced an overpressure condition.		
17	**Construction Plans and Schedule:** At least 90 days prior to the anticipated construction start date, Keystone must submit its construction plans and schedule to the appropriate PHMSA Directors in Central, Western, and Southwest Regions for review. Subsequent plans and schedule revisions must also be submitted to the appropriate Directors, PHMSA Central, Western, and Southwest Regions on a monthly basis.	Part 195 Code does not require the operator to notify PHMSA of construction plans and schedule.	Provides that PHMSA is fully aware of construction plans prior to construction.
18	**Welding Procedures for New Pipeline Segments or Pipe Replacements:** For automatic or mechanized welding, Keystone must use the 20th Edition of API 1104, *Welding of Pipelines and Related Facilities,* for welding procedure qualification, welder qualification, and weld acceptance criteria. Keystone must use the 20th Edition of API 1104 for other welding processes. At least twenty-one (21) days prior to the beginning of any welding procedure qualification activities, Keystone must notify the appropriate PHMSA Directors in Central, Western, and Southwest Regions. Keystone must submit automated or manual welding procedure documentation to the same PHMSA regional office. a) Should nondestructive testing of field girth welds be conducted by automated ultrasonic testing (AUT) API 1104 Appendix A, Keystone must conduct stress analysis for the welding procedures as required in API 1104, Appendix A, Paragraph A.2. b) Should API 1104, Appendix A, be used for welding, Keystone must conduct steel suppliers. c) All welding procedures, AUT procedures and pipe lifting procedures for field construction crews must be documented in construction procedures and field construction crews must be trained in the procedure requirements prior to conducting welding and girth weld AUT in accordance with API 1104, Appendix A. d) Keystone must nondestructively test girth welds in accordance with 49 CFR Sections 195.228, 195.230, and 195.234.	Nondestructive tests required in Code Sections 195.228, 195.230, and 195.234 but not same detail–general, less prescriptive. Only requires 10 percent of each welder's girth welds made each day to be nondestructively tested.	This condition, and Keystone's normal practices, help ensure that every weld is inspected.

Condition	Keystone XL[1]	49 CFR 195	Benefits
19	**Depth of Cover:** Keystone must construct the pipeline with soil cover at a minimum depth of 48 inches in areas, except in consolidated rock. The minimum depth in consolidated rock areas is 36 inches. Keystone must maintain a depth of cover of 48 inches in cultivated areas and a depth of 42 inches in other areas. In cultivated areas where conditions prevent the maintenance of 48 inches of cover, Keystone must employ additional protective measures to alert the public and excavators of pipeline presence. The additional measures must include: a) Placing warning tape and additional line-of-sight pipeline markers along the affected pipeline segment, b) In areas where threats from chisel plowing or other activities are threats to the pipeline, the top of the pipeline must be installed and maintained at least 1 foot below the deepest penetration above the pipeline, not to be less than 42 inches of cover. If a routine patrol (ground and/or aerial) or other observed conditions during maintenance, where farming, excavation, or construction activities are ongoing, or after weather events occur, indicate the possible loss of cover over the pipeline, Keystone must perform a depth-of-cover study and replace cover as soon as practicable, not to exceed 6 months, to meet the minimum depth of cover requirements specified herein. In addition to any depth-of-cover maintenance activities that may take place as a result of routine patrols, Keystone must perform a detailed depth-of-cover survey along the entire Keystone XL pipeline as frequently as practicable, not to exceed once every 10 years, and replace cover as soon as practicable, not to exceed 6 months, to meet the minimum depth-of-cover requirements specified herein.	Code Section 195.248 requires 36 inches of cover and 30 inches of cover in rock. Code does not require future cover maintenance as required in XL Condition 19 a and b.	Helps reduce the probability of mechanical damage through deeper pipeline burial. Requires depth of cover to be maintained at prescribed levels for life of pipeline.
20	**Construction Tasks:** Keystone must prepare and follow an Operator Qualification Program for construction tasks that can affect pipeline integrity. The Construction Operator Qualification Program must comply with 49 CFR 195.501 and must be followed throughout the construction process for the qualification of individuals performing tasks on the pipeline. If the performance of a construction task can affect the integrity of the pipeline segment, the operator must treat that task as a *covered task*, notwithstanding the definition in 49 CFR 195.501(b), and must implement the requirements of Subpart G. Keystone must retain qualification records for each individual performing covered tasks during and after the construction of the pipeline, whether company or contract employee.	General, less prescriptive. Construction personnel training, such as reading project specifications.	Helps ensure that girth weld inspection and repair, and other tasks related to pipeline construction, are performed by qualified individuals.

Condition	Keystone XL[1]	49 CFR 195	Benefits
	Keystone must prepare and follow a Construction Quality Assurance Plan, to ensure quality standards and controls of the pipeline, throughout the construction phase. Such a plan must include, at a minimum, provisions for the following: pipe inspection (at the last pipe shipping or storage location prior to stringing on the construction right-of-way, whether rail yard or pipe yard), hauling and stringing, field bending, welding, nondestructive examination of girth welds, applying and testing field applied coating, lowering of the pipeline into the ditch, padding and backfilling, and hydrostatic testing. These tasks can affect the integrity of the pipeline segment and must be treated as covered tasks. The individuals driving the pipe stringing trucks to the pipeline right-of-way would not need to be Operator Qualification Program qualified, unless they are responsible for the pipe unloading. Other tasks that can affect pipeline integrity which must be treated as covered tasks include, but are not limited to, surveying, locating foreign lines, one-call notifications, ditching, alternating current (AC) interference mitigation and mitigation, CP system surveys, mitigation and installation, conducting directional drills, anomaly evaluations and repairs, right-of-way cleanup (including installing line markers), and quality assurance monitoring. Keystone must provide its construction Operator Qualification Program plan to the appropriate PHMSA Regional Director for review before beginning construction. Girth welds must be inspected, repaired, and nondestructively examined in accordance with 49 CFR 195.228, 195.230, and 195.234. The nondestructive examination (NDE) examiner must have required and current certifications.		
21	**Interference Currents Control:** Control of induced AC from parallel electric transmission lines and other interference issues that may affect the pipeline must be incorporated into pipeline design and addressed during the construction phase. Issues identified and not originally addressed in the design phase must be brought to the attention of the applicable PHMSA Director(s) in Central, Western, and Southwest Regions. Within 6 months after placing the pipeline in service, Keystone must develop and implement an induced AC program to protect the pipeline from corrosion caused by stray currents.	Related to 49 CFR 195.577.	May minimize occurrence of corrosion caused by stray currents.

Condition	Keystone XL[1]	49 CFR 195	Benefits
22	**Pressure Test Levels:** The pre–in-service hydrostatic test must be to a pressure producing a hoop stress of a minimum 100 percent SMYS for mainline pipe and 1.39 times MOP for pump stations for 8 continuous hours. The hydrostatic test results from each test must be submitted in electronic format to the applicable PHMSA Directors in PHMSA Central, Western, and Southwest Regions after completion of each pipeline.	Less prescriptive. Code Section 195.304 requires pressure test 1.25 times, or more, of MOP for at least 4 continuous hours and for pipeline that is not visually inspected for leakage during the test, for at least an additional 4 continuous hours at a pressure equal to 1.1 times or more of MOP.	Helps provide final proof test of the pipeline including testing at greater pressure than required by Code at pump stations prior to placing in-service.
23	**Assessment of Test Failures:** 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 applicable PHMSA Director(s) in Central, Western, and Southwest Regions within 60 days of the failure.	Part 195 Code does not require operator to conduct assessment of test failures of hydrotest failures prior to placing in-service.	Help provide no systemic issues are present should a pre-in-service hydrotest failure be experienced.
24	**Supervisory Control and Data Acquisition (SCADA) System:** Keystone must develop and install a SCADA system to provide remote monitoring and control of the entire pipeline system.	General, less prescriptive. Code Section 195.134 states that a leak detection system must comply, but does not directly state a SCADA system is required.	Helps provide state-of-the-art monitoring and control of the pipeline.
25	**SCADA System – General**: a) Scan rate must be fast enough to minimize overpressure 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 NTSB, SCADA in Liquid Pipelines, Safety Study, NTSB/SS-05/02 specifically including: i. Operator displays must adhere to guidance provided in API 1165 (First Edition), Recommended Practice for Pipeline SCADA Displays. This must be implemented and performed at any location on the Keystone XL system where a SCADA system is used and where an individual is assigned the responsibility to monitor and respond to SCADA information (tanks terminals or facilities also).	General, less prescriptive, although most items are either explicitly listed or inferred as part of the Control Room Management (CRM) regulations through Code Section 195.446.	Provides NTSB findings are included from previous pipeline failure investigations.

Condition	Keystone XL[1]	49 CFR 195	Benefits
	ii. Operators must have a policy for the reviewing and auditing alarms for false alarm reduction and near-miss or lessons-learned criteria. This alarm review must be implemented and performed at any location on the Keystone XL system where a SCADA system is used and where an individual(s) is assigned the responsibility to monitor and respond to alarm information (tanks terminals or facilities also). iii. SCADA controller training must include simulator for controller recognition of abnormal operating conditions, in particular leak events. A generic simulator or simulation must not be allowed by itself as a means to meet this requirement. A full simulator (console screens respond and react as actual console screens) must be required and used for training of abnormal operating conditions wherever possible. iv. See item 29(b) below on fatigue management. v. 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 a controller that are scientifically based, set appropriate work and rest schedules, and consider circadian rhythms and human sleep and rest requirements in line with guidance provided by NTSB recommendation P-99-12 issued June 1, 1999. d) Verify point-to-point display and SCADA system inputs before placing the line in service. This must be implemented and performed at locations on the Keystone XL system where a SCADA system is used and where an individual(s) is assigned the responsibility to monitor and respond to alarm information (tanks terminal or facilities also). e) Implement individual controller log-in provisions. f) Establish and maintain a secure operating control room environment. g) Establish and maintain the ability to make modifications and test these modifications in an off-line mode. The pipeline must have controls in place and be functionally tested in an off-line mode prior to changes being implemented after the line is in service and prior to beginning the line fill stage. h) Provide SCADA computer process load information tracking.		

Condition	Keystone XL[1]	49 CFR 195	Benefits
26	**SCADA – Alarm Management:** Alarm Management Policy and Procedures must address: 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) Controller's performance regarding alarm or event response. h) Alarm indication of abnormal operating conditions. i) Combination abnormal operating conditions or sequential alarms and events. j) Workload concerns. k) This alarm management policy and procedure review must be implemented and performed at locations on the Keystone XL system where a SCADA system is used and where an individual(s) is assigned the responsibility to monitor and respond to alarm information (such as for tanks, terminals, or other associated facilities).	General, less prescriptive, although most items are explicit as part of the CRM regulations through Code Section 195.446.	Helps provide state-of-the-art monitoring and control of the pipeline.
27	**SCADA – Leak Detection System (LDS):** The LDS Plan must include provisions for: a) Implementing applicable provisions in API Recommended Practice 1130, Computational Pipeline Monitoring for Liquid Pipelines (API RP 1130, 1st Edition 2007). b) Addressing the following leak detection system testing and validation issues: i. Test routinely to ensure degradation has not affected functionality. ii. Validate the ability of the LDS to detect small leaks and modify the LDS as necessary to enhance its accuracy to detect small leaks. iii. 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 lead detection criteria in the following areas: i. Minimum size of leak to be detected regardless of pipeline conditions(slack, transient, etc., as related to the Keystone XL pipeline configuration.	General, less prescriptive Code Section 195.134 and 195.444, not as detailed.	Helps provide state-of-the-art monitoring and control of the pipeline.

Condition	Keystone XL[1]	49 CFR 195	Benefits
	ii. Leak location accuracy for various pipeline conditions. iii. Response time for various pipeline conditions. e) Providing redundancy plans for hardware and software and a periodic test requirement for equipment to be used live (also applies to SCADA equipment).		
28	**SCADA – Pipeline Model and Simulator:** The Thermal-Hydraulic Pipeline Model/Simulator including pressure control system must include a Model Validation/Verification Plan.	General, less prescriptive, although measure is inferred as part of the CRM regulations through Code Section 195.446.	Helps provide state-of-the-art monitoring and control of the pipeline.
29	**SCADA – Training:** The training and qualification plan (including simulator training) for controllers must: 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 and that is scientifically based, sets appropriate work and rest schedules, and considers circadian rhythms and human sleep and rest requirements in line with NTSB recommendation P-99-12 issued June 1, 1999. 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 B31Q, Pipeline Personnel Qualification Standard (ASME B31Q, September 2006), for developing qualification program plans. e) Include and implement a full training simulator capable of replaying for training purposes near-miss or lesson learned scenarios. f) Implement tabletop and field exercises no less than five times per year that allow controllers to provide feedback to the exercises, participate in exercise scenario development, and be active participants 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 regarding the position to which certain equipment devices will default upon power loss. i) Include color blind and hearing provisions and testing if these are required to identify alarm priority or equipment status. This review must be implemented and performed at any location on the Keystone	General, less prescriptive, although most items are either explicitly listed or inferred as part of the CRM regulations through Code Section 195.446.	Helps provide state-of-the-art monitoring and control of the pipeline.

Condition	Keystone XL[1]	49 CFR 195	Benefits
	XL system where a SCADA system is used and where an individual(s) is assigned the responsibility to monitor and respond to alarm information (such as for tanks, terminals, or other associated facilities). j) Task-specific abnormal operating conditions and generic abnormal operating conditions training components. 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 RP 1162, Public Awareness Programs for Pipeline Operators (1st edition, December 2003, or the most recent version incorporated in 49 CFR 195.3). l) Implement on-the-job training component intervals established by performance review to include thorough documentation of all items covered during oral communication instruction. m) Implement a substantiated qualification program for requalification intervals addressing program requirements for which circumstances will result in qualifications being revoked; implementing procedure documentation regarding how long a controller can be absent before a review period, shadowing, retraining, or re-qualification is required; and addressing interim performance verification measures between requalification intervals.		
30	**SCADA – Calibration and Maintenance:** The calibration and maintenance plan for the instrumentation and SCADA system must be developed using guidance provided in API RP 1130, Computational Pipeline Monitoring for Liquid Pipelines (1st Edition 2007). Instrumentation repairs must be tracked and documentation provided regarding prioritization of these repairs. Controller log notes must be periodically reviewed for concerns regarding mechanical problems. This information must be tracked and prioritized. Maintenance of field related instrumentation repairs affecting SCADA data (local or remote) must also be tracked, prioritized, and documented at any location on the Keystone XL system where a SCADA system is used and where an individual(s) is assigned the responsibility to monitor and respond to alarm information (such as for tanks, terminals, or other associated facilities).	General, less prescriptive, although measure is essentially required as part of the CRM regulations through Code Section 195.446 (c) (2) that requires point-to-point verification between SCADA displays and related field equipment	Helps provide state-of-the-art monitoring and control of the pipeline through fully functional SCADA system.

Condition	Keystone XL[1]	49 CFR 195	Benefits
31	**SCADA – Leak Detection Manual:** The Leak Detection Manual must be prepared using guidance provided in Canadian Standards Association (CSA), Oil and Gas Pipeline Systems, CSA Z662-03, Annex E, Section E.5.2, Leak Detection Manual.	General, less prescriptive. Many elements inferred through Code Sections 195.134 and 195.444 for leak detection, but code references API 1130 specifically.	Helps provide state-of-the-art monitoring and control of the pipeline reflecting exacting standards.
32	**Mainline and Check Valve Control:** Keystone must design and install mainline block valves and check valves on the Keystone XL system based on the worst-case discharge as calculated by 49 CFR 194.105. Keystone must locate valves in accordance with 49 CFR 195.260 and by taking into consideration elevation, population, and environmentally sensitive locations to minimize the consequences of a release from the pipeline. Mainline valves must be placed based on the analysis above or no more than 20 miles apart, whichever is less. Mainline valves must contain transit inhibit switches that prevent the valves from shutting at a rate (and in conjunction with pumps being shutdown) so that no pressure surges can occur, or other damage caused by unintended valve closures or by closures that are too rapid. Valves must be remotely controlled and actuated, and the SCADA system must be capable of closing the valve and monitoring the valve position, upstream pressure, and downstream pressure so as to minimize the response time in the case of a failure. Remote power backup is required to ensure communications are maintained during inclement weather. Mainline valves must be capable of closure at all times. If it is impracticable to install a remote-controlled valve, Keystone must submit a valve design and installation plan to the appropriate PHMSA Region Director(s), Central, Western, and Southwest Region to confirm the alternative approach provides an equivalent safety level. For valves that cannot be remotely actuated, Keystone must document on a yearly basis not to exceed 15 months that personnel response time to these valves will not take more than an hour.	General Valve Requirements in Code Section 195.260.	Helps provide more instrumentation feeding back data to reduce leak detection times, helps reduce potential spill volumes though prescriptive valve spacing, and helps ensure that valves can close when loss of primary power is experienced. Also helps ensure prompt response time to non-automated valve locations.
33	**Pipeline Inspection:** The entire Keystone XL pipeline (not including pump stations and tank farms) must be capable of passing ILI tools. Keystone must prepare and implement a corrosion mitigation and integrity management plan for segments that do not allow the passage of an ILI device.	ILI required in Code Section 195.120, but no requirements for station piping inspection.	Provides pipeline capable of internal inspection and requires direct assessment plan for pump stations and other facilities.

Condition	Keystone XL[1]	49 CFR 195	Benefits
34	**Internal Corrosion:** Keystone must limit basic sediment and water (BS&W) to 0.5 percent by volume and report BS&W testing results to PHMSA in the annual report. Keystone must also report upset conditions causing BS&W level excursions above the limit. a) Keystone must run cleaning pigs twice in the first year and as necessary in succeeding years based on the analysis of oil constituents, liquid test results, weight loss coupons located in areas with the greatest internal corrosion threat, and other internal corrosion threats. At a minimum in the succeeding years following the first year Keystone must run cleaning pigs once a year, with intervals not to exceed 15 months. b) Liquids collected during the cleaning pig runs, such as BS&W, must be sampled, analyzed and internal corrosion mitigation plans developed based upon the lab test results. **c)** Keystone must review the program at least quarterly based on the crude oil quality and implement adjustments to monitor for, and mitigate the presence of, deleterious crude oil stream constituents.	General, less prescriptive in Code Section 195.579, which requires mitigation of internal corrosion.	Helps provide management of internal corrosion threat during operations.
35	**Cathodic Protection:** The initial CP system must be operational within 6 months of placing a pipeline segment in service.	Required in Code Sections 195.563–within 1 year.	Helps provide early management of external corrosion threat during operations.
36	**Interference Current Surveys:** Keystone must perform interference surveys over the entire Keystone XL pipeline within 6 months of placing the pipeline in service to ensure compliance with applicable National Association of Corrosion Engineers (NACE) International Recommended Practices (RP) 0169 (2002 or the latest version incorporated by reference in Section195.3) and 0177 (2007 or the latest version referenced through the appropriate NACE standard incorporated by reference in 49 CFR 195.3) (NACE RP 0169 and NACE RP 0177) for interference current levels. If interference currents are found, Keystone must determine if there have been adverse effects on the pipeline and mitigate such efforts as necessary. Keystone must report the results of any adverse effects finding and the associated mitigative efforts to the applicable Director(s), PHMSA Central, Western, and Southwest Regions within 60 days of the finding.	Required in Code Sections 195.575 and 195.577–no timing guidelines.	Helps provide early management of external corrosion threat during operations.

Condition	Keystone XL[1]	49 CFR 195	Benefits
37	Corrosion Surveys: Keystone must complete corrosion surveys within 6 months of placing the respective CP system(s) in operation to ensure adequate external corrosion protection per NACE RP 0169. The survey must 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. If placement of a test station is not practical within an HCA, 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 6 months. Remedial actions must include a CIS on each side of the affected test station to the next test station and all modifications to the CP system necessary to ensure adequate external corrosion control.	Required in Code Sections 195.571 and 195.573–timing of 2 years.	Helps provide early management of external corrosion threat during operations.
38	**Initial Close Interval Survey (CIS):** A CIS must be performed on the pipeline within 1 year of the pipeline in-service date. The CIS results must be integrated with the baseline ILI to determine whether further action is needed. Keystone must remediate anomalies indicated by the CIS data including improvements to CP systems and coating remediation within 6 months of completing the CIS surveys. CIS along the pipeline must be conducted with current interrupted to confirm voltage drops in association with periodic ILI assessments under 49 CFR 195.452 (j)(3).	Part 195 Code does not require operator to conduct CIS to confirm cathodic protection systems are performing to protect the pipeline from corrosion.	Helps provide management of external corrosion threat during operations.
39	**Coating Condition Survey:** Keystone must perform a DCVG or ACVG survey within 6 months after operation to verify the pipeline coating conditions and to remediate integrity issues. Keystone must remediate damaged coating indications found during these assessments that are classified as Minor (i.e., 35 percent IR and above for DCVG or 50 dBμV and above for ACVG), Moderate, or Severe based on NACE International RP 0502-2002 Pipeline External Corrosion Direct Assessment Methodology, or the latest version incorporated by reference in Section 195.3. A minimum of two coating survey assessment classifications must be excavated, classified, and/or remediated per each survey crew and pump station discharge section.	Part 195 Code does not require operator to conduct coating surveys after the pipe has been backfilled and graded.	Helps provide early management of external corrosion threat during operations.
40	**Pipeline Markers:** Keystone must install and maintain line-of-sight markings on the pipeline except in agricultural areas or large water crossings such as lakes where line-of-sight signage is not practical. The marking of pipelines may also be subject to environmental permits and	Required in Code Section 195.410, but does not require same level of markers or marker replacement program.	May reduce probability of mechanical damage threat and public awareness of high pressure utility.

Condition	Keystone XL[1]	49 CFR 195	Benefits
	local restrictions. Additional markers must be placed along the pipeline in areas where the pipeline is buried less than 48 inches. Keystone must replace removed or damaged line-of-sight markers during pipeline patrols and maintenance on the right-of-way. Keystone, at a minimum, must identify and replace any missing or damaged line-of-sight markers during pipeline patrols (Condition 41). If pipeline patrolling for Condition 41 is performed via aerial patrolling and cannot consistently identify areas with missing or damaged line-of-sight markers, then Keystone must, on a calendar year basis, not to exceed 15 months, conduct ground patrols.		
41	**Pipeline Patrolling:** Patrol the right-of-way at intervals not exceeding 3 weeks, but at least 26 times each calendar year, to inspect for excavation activities, ground movement, unstable soil, wash outs, leakage, or other activities or conditions affecting the safe operation of the pipeline.	Required in Code Section 195.412, right-of-way patrols every 3 weeks and 26 times per year, but is less prescriptive on items to look for during surveys.	May reduce probability of mechanical damage threat, erosion control, and other threats.
42	**Initial ILI:** Within 3 years of pipeline segment in service, Keystone must perform a baseline ILI using a high-resolution magnetic flux leakage tool. Keystone must perform a baseline geometry tool run after completion of the hydrostatic strength test and backfill of the pipeline, but no later than 6 months after placing the pipeline in service.	Required in Code Section 195.452 within 5 years of placing in-service.	Helps provide early management of external and internal corrosion threat during operations.
43	**Deformation Tool:** Keystone must run a deformation tool through mainline piping prior to putting the product in the pipeline and remediate expanded pipe in accordance with PHMSA's *Interim Guidelines for Confirming Pipe Strength in Pipe Susceptible to Low Yield Strength for Liquid Pipeline* dated October 6, 2009 or subsequent PHMSA update to this guideline.	Not required in Part 195 Code, but PHMSA has issued advisory bulletin on low strength pipe.	Helps provide identification of construction damage and manufacturing defects.
44	**Future ILI:** Future ILI inspection must be performed on the entire pipeline on a frequency consistent with 49 CFR 195.452 (j) (3) assessment intervals or on a frequency determined by fatigue studies of actual operating conditions. a) Conduct periodic CIS along the entire pipeline with current interrupted to confirm voltage drops in association with periodic ILI assessments under Section 195.452(j) (3). b) CIS must be conducted within 3 months of running ILI surveys when using a 5-year ILI frequency, not to exceed 68 months, in accordance with 49 CFR 195.452 (j) (3) assessment intervals. c) CIS findings must be integrated into ILI Tool findings.	Required in Code Section 195.452(j)(3), but does not require a, b, and c.	Helps provide enhanced management of external and internal corrosion threat during operations while overlapping data sets to cross check for issues.

Condition	Keystone XL[1]	49 CFR 195	Benefits
45	**Verification of Reassessment Interval:** Keystone must submit a new fatigue analysis to validate the pipeline reassessment interval annually for the first 5 years after placing the pipeline into service. The analysis must be performed on the segment experiencing the most severe historical pressure cycling conditions using actual pipeline pressure data. The fatigue analysis must be submitted to the appropriate PHMSA Director(s) in Central, Western, and Southwest Regions.	General, less prescriptive in Code Section 195.452, which requires reassessment intervals to be considered in high consequence areas.	Helps provide enhanced management of fatigue threat during operations and PHMSA review.
46	**Flaw Growth Assessment:** Two years after the pipeline in-service date, Keystone must use data gathered on the pipeline section experiencing the most severe historical pressure cycling conditions to determine effect on flaw growth that passed manufacturing standards and installation specifications. This study must be performed by an independent party agreed upon by Keystone and PHMSA. Furthermore, Keystone must share this study with PHMSA and the appropriate Director(s), PHMSA Central, Western, and Southwest Regions within 60 days of its completion, and before baseline assessment is begun. These findings must determine if an ultrasonic crack detection tool must be launched in that pipeline section to confirm crack growth. The study must also define when follow-up review and analysis will occur, not to exceed 5 years, or sooner as determined by the study.	General, less prescriptive in Code Section 195.452, which requires reassessment intervals to be considered in high consequence areas.	Helps provide enhanced management of fatigue threat during operations.
47	**Direct Assessment Plan:** Headers, mainline valve bypasses, and other sections that cannot accommodate ILI tools must be part of a Direct Assessment Plan or other acceptable integrity monitoring method using External and Internal Corrosion Direct Assessment criteria.	General, less prescriptive in Code Section 195.452, but not as detailed.	Helps provide enhanced management of corrosion threat during operation for non-pigable sections of piping inside facilities.
48	**Damage Prevention Program:** Keystone must incorporate the Common Ground Alliance's damage prevention best practices applicable to pipelines into its damage prevention program.	General, less prescriptive in Code Section 195.442, operator is not required to meet Common Ground Alliance's damage prevention best practices.	Helps provide enhanced public awareness as part of damage control programs.

Condition	Keystone XL[1]	49 CFR 195	Benefits
49	**Anomaly Evaluation and Repair:** Anomaly evaluations and repairs must be performed based upon the following: a) Immediate Repair Conditions: Follow 49 CFR 195.452(h)(4)(i) except designate the calculated remaining strength failure pressure ratio (FPR) ≤ 1.16 for anomaly repairs; b) 60-day Conditions: Follow 49 CFR 195.452 (h)(4)(ii) except designate a FPR ≤ 1.25 for anomaly repairs; c) 180-day Conditions: Follow 49 CFR 195.452 (h)(4)(iii) with exceptions for the following conditions which must be scheduled for repair within 180 days: i. Calculated FPR = < 1.39; ii. Areas of corrosion with predicted metal loss greater than 40 percent; iii. Predicted metal loss is greater than 40 percent of nominal wall that is located at crossing of another pipeline and; iv. Gouge or groove greater than 8 percent of 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 to determine the maximum reinspection interval. e) Anomaly Assessment Methods: Keystone must confirm the remaining strength (R-STRENG) effective area method, R-STRENG-085dL, and ASME B31G assessment methods are valid for the pipe diameter, wall thickness, grade, operating pressure, operating stress level, and operating temperature. Keystone must use the most conservative method until proper method confirmation is made to PHMSA headquarters. f) Flow Stress: Remaining strength calculations for X-80 pipe must use a flow stress equal to the average of ultimate (tensile) strength and SMYS. g) Dents: For initial construction and the initial geometry tool run, Keystone must remove dents with a depth greater than 2 percent of the nominal pipe diameter 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	General, less prescriptive. Required in Code Section 195.452, except Code does not require immediate repair when FPR is less than 1.16 (Code requires less than 1.0, which is less than MOP with no safety factor) and does not require 180-day repair if wall loss is less than 50 percent.	Helps provide timely investigation and prompt repair of anomalies in the pipeline reported via in-line inspection.

Condition	Keystone XL[1]	49 CFR 195	Benefits
	dent is measured as the gap between the lowest point of the dent and the prolongation of the original contour of the pipe.		
50	**Reporting – Immediate:** Keystone must provide immediate notification of reportable incidents in accordance with 49 CFR 195, and must notify the appropriate PHMSA regional office within 24 hours of non-reportable leaks occurring on the pipeline.	General, less prescriptive. Required in Code Sections 195.50, 195.52, 159.54, 195.55, and 195.56, except nonreportable leaks do not require reporting.	Provides enhanced transparency to PHMSA.
51	**Reporting – 180 day:** Within 180 days of the pipeline in-service date, Keystone must report on its compliance with these conditions to the PHMSA Associate Administrator and the appropriate PHMSA Directors in Central, Western, and Southwest Regions.	Part 195 Code does not require operator to give PHMSA a 180-day overview of operations on new pipelines.	Provides enhanced transparency to PHMSA.
52	**Annual Reporting:** Keystone must annually report by February 15th each year the following to the PHMSA Associate Administrator and the appropriate Directors, PHMSA Central, Western, and Southwest Regions: a) The results of an ILI run or direct assessment results performed on the pipeline during the previous year; b) The results of internal corrosion management programs: i. BS&W analyses ii. Report of plant upset conditions where elevated levels of BS&W are introduced into the pipeline iii. Corrosion inhibitor and biocide injection iv. Internal cleaning program v. Wall loss coupon tests c) New integrity threats identified during the previous year; d) An encroachment in the right-of-way, including the number of new residences or public gathering areas; e) HCA changes during the previous year; f) Reportable incidents that occurred during the previous year; g) Leaks on the pipeline that occurred during previous year; h) A list of repairs on the pipeline made during the previous year; i) On-going damage prevention initiatives on the pipeline and an evaluation of their success or failure; j) Changes in procedures used to assess and monitor the pipeline; and k) Company mergers, acquisitions, asset transfers, or other events affecting regulatory responsibility of company operating the pipeline.	Part 195 Code does not require operator to give PHMSA an annual overview of operations on new pipelines.	Provides enhanced transparency to PHMSA.

Condition	Keystone XL[1]	49 CFR 195	Benefits
53	**Threat Identification and Evaluation:** Keystone must develop a threat matrix consistent with 49 CFR 195.452 to accomplish the following: a) Identify and compare increased risks of operating the pipeline; and b) Describe and implement procedures used to mitigate the risk. c) Where geotechnical threats exist that may impact operational safety, Keystone must run a geospatial tool and assess procedures to implement for conducting mitigative measures along the affected pipeline.	Part 195 Code does not require operator to develop a threat matrix on locations outside high consequence areas.	Helps provide state-of-the-art integrity management practices employed across the entire pipeline system that would identify risks and develop plans.
54	**Right of Way Management Plan:** Keystone must develop and implement a right-of-way management plan to protect the Keystone pipeline from damage due to excavation, third party, and other activities. In areas where increased activities or natural forces could lead to increased threats to the pipeline beyond the initial threat conditions, the management plan must include increased inspections. The management plan must also include right-of-way inspection activities to complement the following: a) Depth of Cover (Condition 19) b) Pipeline Markers (Condition 40) c) Pipeline Patrolling (Condition 41) d) Damage Prevention Program (Condition 48); and e) Threat Identification and Evaluation (Condition 53). The Right-of-Way Management Plan and all the above-listed right-of-way inspection activities, Conditions 19, 40, 41, 48, and 53, must be reviewed for effectiveness and procedures updated as required on a periodic basis as conditions change, but not longer than once per calendar year not to exceed 15 months.	Part 195 Code does not require operator to develop a Right-of-Way Management Plan for threats along the pipeline. This requirement is similar to the natural gas pipeline, Part 192 – Alternative Maximum Allowable Operating Pressure Rule, 80 percent SMYS.	Helps provide increased right-of-way inspections and protects against external damage to pipeline.
55	**Records:** Keystone must maintain records demonstrating compliance with the conditions herein for the useful life of the pipeline.	Part 195 Code does not require operators to maintain compliance records for life of the pipeline.	Maintains compliance records for the life of the pipeline.

Condition	Keystone XL[1]	49 CFR 195	Benefits
56	**Certification:** A senior executive officer of Keystone must certify the following in writing: a) That Keystone has met the conditions described herein; b) That the written design, construction, and operating and maintenance plans and procedures for the Keystone pipeline have been updated to include additional requirements herein; c) That Keystone has reviewed and modified its damage prevention program relative to the Keystone pipeline to include additional elements required herein. Keystone must send a copy of the certification with the required senior executive signature and date of signature to PHMSA Associate Administrator and the Directors, PHMSA Central, Western, and Southwest Regions at least 90 days prior to operating the Keystone Pipeline.	General less prescriptive, Part 195 Code does not require senior executive to certify compliance prior to operations at a certain pressure level.	Helps ensure senior management accountability and visibility to aspects of the project's design, construction, and operations.
57	Within 1 year of the in-service date, Keystone must provide a detailed technical briefing, in person, to the appropriate PHMSA Directors in Central, Western, and Southwest Regions. The briefing must cover the implementation of the requirements of the conditions herein, including information required by Condition 52. On the basis of PHMSA's review of the Condition 52 Annual Report and additional information provided at the briefing, PHMSA may require additional information.	Part 195 Code does not require 1-year technical briefing of pipeline operations by operator to PHMSA.	Provides yearly in person reporting to PHMSA, increasing visibility and transparency to pipeline safety regulator.

AC = alternating current
ACVG = alternating current voltage gradient
API = American Petroleum Institute
ASME = American Society of Mechanical Engineers
ASTM = American Society of Testing and Materials
AUT = automated ultrasonic testing
BS&W = basic sediment and water
C = Celsius
CE = carbon equivalent
CFR = Code of Federal Regulations
CIS = close interval survey
CP = cathodic protection
CRM = control room management
CSA = Canadian Standards Association
dBμV =decibel-microvolts
DCVG = direct current voltage gradient
F = Fahrenheit
FBE = fusion bond epoxy
FPR = failure pressure ratio
HCAs = High Consequence Areas
IIW = International Institute of Welding
ILI = in-line inspection
IR = current (I) flowing through a resistance (R)
LDS = leak detection system
MOP = maximum operating pressure
NACE = National Association of Corrosion Engineers
NDE = nondestructive examination
NTSB = National Transportation Safety Board
PHMSA = Pipeline and Hazardous Materials Safety Administration
PSL = product specification level
R-STRENG = remaining strength
RP = Recommended Practice
SCADA = Supervisory Control and Data Acquisition
SMYS = specified minimum yield strength
UT = ultrasonic test
V = volt

In addition to the 57 Special Conditions listed above, two additional Special Conditions include:

1. Keystone would develop and implement a Quality Management System that would apply to the construction of the entire Keystone XL project in the U.S. to ensure that this pipeline is–from the beginning–built to the highest standards by both Keystone personnel and its many contractors; and
2. Keystone would hire an independent Third Party Inspection Company (TPIC) to monitor the construction of the Keystone XL project. PHMSA must approve the TPIC from among companies Keystone proposes. Keystone and PHMSA would work together to develop a scope of work to help ensure that all regulatory and technical EIS conditions are satisfied during the construction and commissioning of the pipeline project. The TPIC would oversee the execution and implementation of the Department-specified conditions and the applicable pipeline safety regulations and would provide monitoring summaries to PHMSA and Keystone concurrently. Keystone would address deficiencies or risks identified in the TPIC's assessments.[3]

3.0 MITIGATION MEASURES RECOMMENDED IN THE BATTELLE AND E^X^PONENT RISK REPORTS

The following summarizes mitigation recommendations from the Battelle and E^x^ponent risk assessment reports. Keystone has committed to implement the following mitigation recommendations, including specifically addressing several issues in its Emergency Response Plan and Oil Spill Response Plan (and its risk analysis that is used in the development of those plans). The recommendations are grouped under numbered themes. Where recommendations were duplicate or very similar, the recommendations were combined and summarized under the theme. Acronym definitions are listed at the end of this summary.

1. The Facility Response Plan (FRP), Integrity Management Plan (IMP), and other related plans would be updated to include more frequent inspections or the use of advanced or improved leak prevention/detection tools, technology, or resources based on demonstrated need, environmental sensitivity, and/or changing conditions identified during pipeline operation.
    a. Preventing leaks is a primary goal because any leak could release product into potentially sensitive ecosystems or into critical resources. Flexibility is recommended in the inspection plan and requirements to ensure that prevention is effective over the lifecycle of the proposed Project.

[3] In response to a data request regarding this TPIC condition, Keystone responded: "Keystone agrees to hire an independent Third Party Inspection Company (TPIC) to monitor field construction activities of the Keystone XL project. Keystone understands that it will work jointly with PHMSA to define the scope of work, identify qualified companies and prepare a Request for Proposal. PHMSA will select the qualified TPIC and manage the work of the TPIC. PHMSA will retain authority for its mandate on the project, while the TPIC will provide supplementary resources to PHMSA staff to field monitor, examine, audit and report conditions as specified by DOS and applicable pipeline safety regulations. Keystone will address deficiencies as directed by PHMSA."

b. A risk-based integrity management system would be used whereby the frequency and accuracy requirements of in-line inspection (ILI) are based on a quantitative risk assessment indicated by conditions found after each inspection.

c. Inspection for mechanical damage using other technologies would also be considered in selected areas where the chance for such damage is locally higher.

d. Use of in-line leak detection technology on a selected basis may be appropriate in more environmentally sensitive areas, in areas where third-party damage is more likely, and on segments after significant corrosion is indicated.

e. In-line leak detection also could be considered in the future for line segments that have experienced significant corrosion or on segments where excavation equipment may have impacted the pipeline.

f. In-line leak detectors would also be deployed as part of the pig trains run under the integrity management programs. Leaks are not expected to be frequent; however, because many failures are the result of human activities, it is recommended that Keystone assess in its ERP/Spill Response Plan (SRP) the efficacy of increasing aerial surveys and/or ground patrol frequency to once a week.

g. Analysis by E^{x}ponent indicates that leaks larger than about 20 barrels could be detectable aboveground (visually or by other sensor) within a reasonable timeline. Spills of about 1,400 barrels could be detected within 2 hours under Keystone's[4] current detection commitment. Reasonable expectations based on unpublished data suggest that this volume could be reduced to several hundred barrels detected within 45 minutes. Though encouraging, smaller leaks are still a concern. Given that leaks of less than 20 barrels are not easily detectable aboveground, consideration would be given to the use of automated leak detection technologies. These technologies could complement continuous pipeline monitoring (CPM) and the other schemes currently adopted, with the survey frequency matched to the specific technology considered.

h. Given that E^{x}ponent's work indicates that leaks of more than 20 barrels could be recognized within a reasonable timeframe aboveground (detectable visually or by other sensor), the use of detection technologies would be considered, along with a patrol frequency that is matched to such technologies.

i. Given that E^{x}ponent's work indicates that large leaks could be recognized within a reasonable timeframe aboveground (detectable visually or by other sensor), consideration would be given to the use of detection technologies that complements computational pipeline modeling/monitoring CPM and the other schemes currently adopted, and to a patrol frequency that is matched to such technologies.

j. E^{x}ponent recommends that Keystone consider how to improve upon external leak detection through more frequent inspections and property owner education for wells within these areas of sensitive groundwater resources.

k. If significant corrosion is detected by the lower-cost ILI tools, then high-resolution magnetic flux leakage (MFL) tools, more frequent inspection, or better tools are recommended.

[4] TransCanada Keystone Pipeline, LP (Keystone).

l. In their original (January 2012) and final (June 2013) reports, Battelle recommended increased aerial pipeline surveillance beyond what is currently required by PHMSA regulations. Battelle believes this recommendation is a valid one. Survey/patrol frequency even at the nominal two-week interval is largely ineffective based on the following analyses:

   - Analyses done by Battelle over the years indicate that the likelihood of missing an encroachment action at a 2-week patrol frequency was high.
   - Work done by C-FER (Reliability Based Prevention of Mechanical Damage to Pipelines) likewise indicates about a 90 percent chance of non-detection at 2-week intervals.

2. The IMP and other related plans would consider new developments in leak prevention and detection tools as these new technologies mature and demonstrate viable improvement.

   a. No matter how effectively pipeline systems are designed and constructed, there will always be a finite chance that a leak will occur. Therefore, leak detection is essential across the range of potential release components of the pipeline. Because facility risks are significant, it is recommended that leak detection efforts be placed on both the mainline pipe sections and facilities (including tanks). As new leak detection technologies emerge and start to be deployed in the field, Keystone would continue evaluating these technologies and consider implementing them if they represent a significant increase in leak detection sensitivity.

   b. Regarding small leak detection, Keystone would plan to consider those developments and aggressively move to implement viable technology as time passes and technology evolves and matures. Based on responses to inquiries made over the course of the work that show Keystone investing through ongoing industry activities, such actions would be a part of Keystone's change management practices. Alternative approaches to prevent leaks would also be considered.

   c. Four types of emergency flow restricting devices exist: remote controlled valves, check valves, automatic control valves, and manually operated valves. There is evidence that all but automatic control valves are involved in the proposed Project (note that the manually operated valves are placed in conjunction with and just downstream of the check valves). Automatic control valves respond automatically to pipeline flow conditions, which poses the chance for anomalous response. Yet, an automatic control valve conceptually represents a simple leak detection system (LDS) and an emergency flow restricting device in one package. As the technology matures, consideration would be given to such devices as these become reliable and can be programmed to close and minimize surge.

3. The FRP, IMP, and other related plans would include periodic revisions throughout the lifecycle of the proposed Project as new information becomes available from Keystone's observations, inspections, and lessons learned, particularly in the context of updating equipment, tools, and standard operating procedures. Also, the FRP, IMP, and other related plans would include regular monitoring of all aspects of prevention, protection, and mitigation to ensure that operations are conducted in accordance with the current plans.

   a. Equipment-related concerns represent a viable threat, which would either be addressed, or demonstrated through analysis or trending that they can be ignored.

   b. Incorrect operations would be included as a threat unless demonstrated that it is not relevant. Concern exists in this context regarding human error, failure to follow standard operating procedures (SOPs), and/or the existence of outdated SOPs.
   c. Leak prevention is a primary goal because any leak could release product into potentially sensitive ecosystems or into critical resources. Flexibility is recommended in the inspection plan and requirements to ensure that prevention is effective over the lifecycle of the proposed Project.
   d. Finally, all aspects of prevention, protection, and mitigation would be monitored to ensure that plans and commitments remain viable and are implemented as outlined to date. Care would also be taken to heed the guidance that is emerging from recent efforts to avoid potential incidents[5] built in during construction.
4. The IMP and other related plans would require that in-line leak detection be considered as part of a pig train run to assess the pipeline for corrosion.
   a. It is recommended that in-line leak detection be considered as part of the pig train that would be run to assess the pipeline for corrosion. This helps ensure that no small leaks have developed and that any leaks missed by other schemes have minimal environmental impact, while also minimizing the impact to operations (as the pipeline throughput is already reduced during pigging).
5. The IMP and other related plans would require that consideration be given to the selective use of concrete-coated line pipe or other unique approaches (like concrete pads and berms) to protect location-specific elements, such as facilities sited in sensitive ecosystems.
   a. Depending on the nature of the terrain, aspects of the water table, and other factors, consideration would be given to the selective use of concrete-coated line pipe, or an equivalent that, unlike concrete coating, can be field-bent and cathodically protected (CP).
   b. For location-specific elements, like facilities that are currently sited in sensitive ecosystems or resources, Keystone would also consider unique approaches to protect those sites, such as containment of facility leaks through the use of concrete pads and berms.
6. The IMP and other related plans would include proactive performance of in-line inspections (ILIs) prior to the start of operations in addition to inspections during operations. ILIs along the mainline pipe could be performed proactively prior to the start of operations to detect major defects in welds and the pipe wall, as well as defects caused by pipe placement in the ground. Defects detected could be repaired before the start of operations, thereby reducing the probability that a leak would occur soon after the start of operations.
   a. The objective of this task was to quantify the effectiveness of the current design, construction, and operation practices in preventing leaks. Along the mainline pipe, leak prevention focuses on detection of defects in the pipe itself, on the longitudinal welds made during fabrication, and on the girth welds that connect the line pipe across the right-of-way. Battelle's evaluation of leak prevention considered the effectiveness of wall

[5] The terms *incident* and *accident* can be used interchangeably or with specified definitions in various agency reports and databases. For the purposes of this report, the term *incident* has been selected for consistency.

thickness, controls for steel and longitudinal seams, and the external coating placed on the pipe and on the girth welds, as well as on the CP system. It is recommended that ILIs be performed proactively before starting operations. These inspections are capable of detecting major defects in welds and in the pipe wall, as well as defects caused by placing the pipe in the ground. Any detected defects could be repaired before starting operations and thereby would reduce the probability that a leak would occur soon after the start of operations.

7. The FRP and other related plans would require response resources to comply with the 12-hour regulatory requirement under all circumstances and commit to a response time significantly less than the maximum response time required by 49 CFR 194, at all locations along the pipeline, as feasible. Keystone's Emergency Response Plan would identify the resources required and dispatch of these resources to satisfy this commitment and minimize impact to the public and sensitive ecological areas.
   a. During the construction phase, response team and equipment needs would be identified based on the scope of transported products and their potential interaction with the ecosystems that the pipeline traverses. Keystone has recently stated concurrence with this action and has indicated that they would target response plans to the ecosystems and resources traversed and would commit to a response time significantly less than the maximum response time required by 49 CFR 194, at all locations along the pipeline, as feasible.
   b. E^{x}ponent recommends that the ERP consider the possibility that spilled oil may be entrained into sediments and that these types of conditions (sediment/oil mix) be anticipated as part of response and cleanup.
   c. The ERP would also take into account the sensitive areas identified in our review (e.g., Rainwater Basin, small stream crossings associated with ecologically sensitive areas, and special downstream water bodies). For example, wildlife habitat for special status species, within close proximity of the pipeline could be designated as *special and/or unique areas* for purposes of the ERP.
8. The IMP and other related plans would require that defect tolerance of girth welds is assessed and achieved, subject to the PHMSA process.
   a. Regarding axially-oriented anomalies, analysis of anomaly response and trending of the incident causes as a function of the diameter clearly shows, according to the Battelle/E^{x}ponent risk assessment, that the lineal portion of the proposed Keystone XL Project is robust from a preventive perspective. Regarding girth welds, care would be taken to ensure that similar analyses are considered, and that related defect tolerance is assessed and achieved, subject to the PHMSA process.
9. The FRP and other related plans would consider groundwater monitoring wells inside and outside high consequence areas (HCAs). The location for the monitor wells would take into consideration distance, elevation, population, environmentally sensitive locations, and geotechnical threats, all of which would be documented.
   a. E^{x}ponent does not recommend monitoring non-HCA clusters of wells or installing additional monitoring wells prior to an oil release. However, E^{x}ponent recommends that non-HCA clusters of wells be considered while evaluating response plans.

10. The IMP and other related plans would validate safe valve closure times (e.g., 12 minutes) for the pipeline.

    a. Valve response times for liquid lines are limited by the potential of fluid hammer and related overpressure surge. The published literature points to issues regarding times of about 10 minutes, and much more in some cases. Therefore, concern exists regarding the closure interval, noted currently at 12 minutes. If this process transitions to the PHMSA, care would be taken to validate the underlying dynamic analysis and related plans.

11. The IMP and other related plans would consider more frequent scheduled maintenance for valves and other equipment, pre-service offsite leak checks, and equipment testing when inspection and maintenance data indicate an increased service need.

    a. Since pipeline areas where seals and seats are present have a higher potential for spills (e.g., on equipment and pumps), Keystone would be diligent about material selection for seals and seats, from both the design and maintenance perspectives, over the lifecycle of the equipment. They would also consider more frequent scheduled maintenance for valves and other equipment, at least initially, and use pre-service offsite leak checks and equipment testing where plausible.

12. The risk assessment required by PHMSA in 49 CFR 195.452 would include the reasoning as to why other threats, which are included in American Society of Mechanical Engineers (ASME) B31.8S, are excluded. Keystone has used the threat categories in the guidance available in ASME B31.8S, which are similar, but not the same as those categories listed in ASME B31.8S. *Other threats* include those other than the following nine categories: external corrosion, internal corrosion, stress corrosion cracking, materials related, construction related, equipment, excavation, hydraulic events, and natural hazards.

    a. A rationale would be provided for the exclusion of other threats included in ASME B31.8S.

13. The risk assessment required by PHMSA in 49 CFR 195.452 would include the use of a typical spill volume of 33 barrels, as calculated by Battelle for the system's mainline pipe section based on the geometric mean for reported incidents between January 2002 and December 2012.[6]

    a. The PHMSA Liquid Hydrocarbon Incident Database should continue to be used, but the analysis should be limited to crude oil spills and should consider the very different spill performance data for major systems (i.e., mainline pipe). The results should be presented without the use of engineering adjustment factors. A conservative performance range could be presented if an updated spill frequency estimate is needed for the entire pipeline. Appendix K, Historical Pipeline Incident Analysis, of the Final Supplemental Environmental Impact Statement (EIS) should be used as the starting point for such an updated analysis. Until that re-evaluation is performed, it is recommended that, for planning purposes, a medium spill volume of 100 barrels be used. A larger volume may have to be used in locations where the terrain produces a hydraulic gradient.

[6] This RFI (request for information) was generated based on a recommendation in Battelle's DRAFT October 16, 2013 letter, which supersedes the earlier recommendation in Battelle's June 2013 Independent Engineering Report to use a typical spill volume of 100 barrels.

b. The Final EIS (FEIS)[7] discusses the typical spill volume to be expected should a release occur from the Keystone XL pipeline. In the FEIS, TransCanada recommended 3 barrels; in the Independent Engineering Assessment, Battelle suggested 100 barrels as a typical spill volume. The TransCanada value was based on the median and the Battelle value was based on the arithmetic mean. Battelle has indicated the spill distribution to be lognormal, and the value for the typical spill should be the geometric mean. The geometric mean value for all spills that occurred between January 2002 and December 2012 is 33 barrels for the mainline pipe section of the system. The discussions on pages ES-3 and ES-4 and in Section 3.3 of the Engineering Assessment should now be based on the geometric mean value.

14. The risk assessment required by PHMSA in 49 CFR 195.452 would include a threat-based sensitivity analysis including scope and results. Battelle suggests that such a sensitivity analysis could help identify localized threats, but sensitivity analysis apparently was not used to understand underlying drivers for incidents when estimating spill frequencies.

    a. Sensitivity analysis apparently was not used to understand underlying drivers for incidents by Keystone when estimating spill frequencies. Such analysis could help identify localized threats. Further, although Keystone might have relied on subject matter experts (SMEs) to help quantify infrequent events like flash floods, general flooding, landslides, etc., the scope and results of such activity are not clearly evident.

15. The risk assessment required by PHMSA in 49 CFR 195.452 would include incident likelihood related to applying alternative preventive, protective, and mitigative features along the pipeline, considering the importance of potentially large localized spill events and/or smaller periodic spill events.

    a. Regarding expressions of average risk, care should be taken when stating a U.S. threat rate or a state-level incident rate because this downplays the absolute importance of potentially large localized and/or periodic events. This practice does not help focus preventive, protective, or mitigative actions at specific locations along the pipeline, so an alternative risk assessment approach should be adopted if the PHMSA approves construction. At that time, Keystone should assess incident likelihood considering the benefits of alternative, preventive, protective, and mitigative features in place.

16. The risk assessment required by PHMSA in 49 CFR 195.452 would include additional quantitative analyses of transport and fate processes similar to the modeling and analysis presented in E^{x}ponent's report, as well as assessing overland flow (spreading) and transport along the new route, particularly for specific pipeline sections that intersect identified sensitive habitats.

    a. Consideration should be given to additional quantitative analyses of transport and fate processes similar to the modeling and analysis presented in E^{x}ponent's report. Proactive measures could help limit the likelihood of a spill to sensitive areas, as well as leak detection systems, which could limit the amount, and hence the spread, of crude oil released.

[7] Published August 26, 2011.

17. The risk assessment required by PHMSA in 49 CFR 195.452 would include additional modeling as part of a final design of the proposed Project to further refine appropriate downgradient distance criteria that could be used for identifying sensitive clusters of wells (i.e., domestic wells, irrigation wells, etc.).

    a. E^{x}ponent developed and applied criteria to identify potentially sensitive environments downstream of small stream crossings, with a number of such environments identified along the pipeline route. From an engineering perspective, concern for small streams could and would be managed proactively during construction via micro-bore or such techniques. During construction, and continuing into the operational phase, further analysis would be done to assess overland flow (spreading) and transport for specific pipeline sections that intersect identified sensitive habitats, including the four streams identified by E^{x}ponent. This modeling exercise could then be used to inform ERPs. Well depth and depth of release would also be assessed relative to the water table to screen/identify sensitive groundwater resources that may be more vulnerable to exposure to a hydrocarbon plume in the event of an oil spill. Finally, it is recommended that the presence of polycyclic aromatic hydrocarbons (PAHs) and naphthenic acids be better quantified for the products that are actually transported in the pipeline to better inform environmental remediation and response planning.

18. The risk assessment required by PHMSA in 49 CFR 195.452 would require a surface water spill distance of at least 10 miles downstream from the proposed pipeline centerline for identifying sensitive areas and contributory pipeline segments (CPSs) during the final design phase of the proposed Project.

    a. Additional spreading analyses would be performed in areas where sensitive environmental receptors are found, to demonstrate that these areas are adequately protected and that additional valves would not have a net benefit. These calculations would be most useful early in the process, before the formal validation of valve placement, demonstrating that the placement does minimize spill volumes.

19. The risk assessment required by PHMSA in 49 CFR 195.452 would factor into its quantitative risk analysis the cause and effect of *other*, *other outside force damage*, and *equipment* cause categories and nulls in the PHMSA incident/accident dataset, to the extent that valid data exists to perform this work.

    a. The Keystone analysis does not describe how the causes under the *other*, *other outside force damage*, and *equipment* cause categories were factored into the analysis and threat identification process. When the likelihood analysis more broadly expands to consider such incidents, as well as those at facilities, the nulls would be addressed. This would be considered in any update of the pipeline risk assessment if PHMSA gives approval for construction. Finally, the recommendations noted in the qualitative threats review done from a pipeline perspective are supported quantitatively.

    b. A quantitative rationale would be presented for causes that have not been recognized as threats. Keystone would detail their data screening process and the method(s) to deal with nulls, so that a simple query could replicate the baseline frequencies on a threat-specific basis. Keystone employed a query process using the CAUSE and GEN_CAUSE fields to obtain their cause/threat results. Further, it appears that their outcomes exclude the facilities that are an essential element of any pipeline system. Therefore, Battelle suggests that the risk assessment could be recast in a more generic setting. While currently restricted to use by government agencies and selectively by operators, a better approach would capitalize on the PHMSA National Pipeline Mapping System website to geo-locate the historic spill records as the means to better quantify localized threats.

c. The PHMSA list of general cause codes is longer than the list of cause codes TransCanada developed using ASME B31.8S and American Petroleum Institute (API) 1160. ASME B31.8S and API 1160 list more sub-elements under fewer cause codes. For the EIS assessments, the damage codes used in the PHMSA database would be used. Over time, the damage codes from the standards would supplement these damage codes, but because they are more focused, they would not be used for EIS assessments.

20. Given the dominance of risks associated with the mainline pipe and other system components (i.e., those components other than mainline valves or tanks), the risk assessment required by PHMSA in 49 CFR 195.452 would consider a risk management program that addresses these two categories of system components to effectively reduce risk. In comparing the average risks associated with the four system components analyzed (mainline pipe, mainline valves, tanks, and other system components), 97 percent of the risk was related to the mainline pipe and other system component risks. These two risk components represent the risks associated with the mainline pipe and fixed facilities such as pumping stations. The risk assessment would assess the individual components and threats to the pipeline system separately when evaluating risk, conducting incident frequency calculations, and evaluating trends.

   a. In comparing the average risks associated with the four system components analyzed (mainline pipe, mainline valves, tanks, and other system components) 97 percent of the risk was in the mainline pipe and other system component risks with the risk almost evenly split. These two risk components represent the risks associated with the mainline pipe and fixed facilities such as pumping stations. Given the dominance of these two system components, a risk management program that addresses these system components would be most effective in reducing risk.

   b. As a result of an internal review of the Risk Assessment Report, Battelle performed a statistical analysis of both the onshore crude oil spill volumes and total damage costs reported to PHMSA. The statistical analyses revealed that both the spill volumes and total damage cost estimates were found to be lognormally distributed. As a result of this finding, it was shown that there is a statistically significant difference, at the 95 percent confidence level, between the spill volumes and total damage costs for the four system components used in the Risk Assessment and in Appendix K, Historical Pipeline Incident Analysis, of the Final Supplemental EIS.

21. Spill prevention as covered in the ERP, IMP, and related plans would consider a spill's effect on wetlands and streams used by federally protected species and candidate species throughout the lifespan of the proposed Project and Keystone would work with the USFWS as appropriate.

   a. E^{x}ponent does not recommend designating the entire whooping crane migration corridor as an HCA. Rather, E^{x}ponent has recommended mitigation measures at the stream crossings and associated wetlands in the proposed Project area that bisect the whooping crane migration corridor as shown on the maps provided in E^{x}ponent's Third-Party Consultant Review of the TransCanada Keystone XL Pipeline Risk Assessment.

b. As with whooping cranes, E^xponent does not recommend designating the entire migration corridors as HCAs for other migratory special status species. Rather, E^xponent has recommended mitigation measures at the stream crossings and associated wetlands used by migratory special status species.

c. Critical habitat would be protected and it qualifies as an HCA. Data from the USFWS regarding critical habitat that could be affected by a spill would be included in the more detailed analysis required by PHMSA. E^xponent recommends that the stream crossings and attendant wetlands it has identified would also be mitigated as part of the ERP.

d. Fifty-nine small stream crossings within the Rainwater Basin Wildlife Management District (RBWMD) have special status wetlands at the stream crossings that could potentially be used by whooping cranes and other wetland-dependent special status species. For this reason, E^xponent recommends that these stream crossings would be considered for additional mitigation measures to protect the whooping crane habitat of the RBWMD because of its importance as a stopover area for whooping crane feeding and resting.

e. While most whooping cranes stay within their migration corridor, they are seen outside the corridor on a regular basis and may have even begun prospecting new areas. Related to this point, many other special status species are capable of using new areas on a yearly basis. A further complication is that, according to the United States Geologic Survey (USGS), many water bird habitats within the RBWMD may be in a state of deterioration, and may already be compelling whooping cranes to use unprotected wetlands within the proposed Project. Therefore, E^xponent suggests that Keystone would conduct a bi-annual consultation with U.S. Fish and Wildlife Service (USFWS) to identify areas of high potential for use by special status species and to update the proposed Project ERPs as appropriate.

f. Given the 50-year projected lifespan of the proposed Project and the possibility that one or more special status species may move into the Project vicinity during that timeframe, E^xponent concludes that the monitoring outlined in 49 CFR 195 may be insufficient to protect special status species over the lifespan of the Project. Specifically, E^xponent recommends that, in addition to monitoring physical factors that might impact pipeline integrity, Keystone develop a biological monitoring plan for these special and unique special status habitats to periodically determine whether threatened and endangered (T&E) and other special status species are using these habitats within the Project area and whether they are afforded sufficient protection under the ERP.

22. Evaluation of the pipeline throughout the lifespan of the proposed Project would consider federally protected species and candidate species to assure that the provisions of the USFWS' Keystone XL Pipeline Biological Opinion under Section 7 of the Endangered Species Act (ESA) are met.

    a. E^xponent does not recommend designating the entire whooping crane migration corridor as an HCA. Rather, E^xponent has recommended mitigation measures at the stream crossings and associated wetlands in the proposed Project area that bisect the whooping crane migration corridor as shown on the maps provided in E^xponent's Third-Party Consultant Review of the TransCanada Keystone XL Pipeline Risk Assessment.

b. As with whooping cranes, E[x]ponent does not recommend designating the entire migration corridors as HCAs for other migratory special status species. Rather, E[x]ponent has recommended mitigation measures at the stream crossings and associated wetlands used by migratory special status species.

c. Critical habitat would be protected and it qualifies as an HCA. Data from the USFWS regarding critical habitat that could be affected by a spill would be included in the more detailed analysis required by PHMSA. E[x]ponent recommends that the stream crossings and attendant wetlands it has identified would also be mitigated as part of the ERP.

d. Fifty-nine small stream crossings within the RBWMD have special status wetlands at the stream crossings that could potentially be used by whooping cranes and other wetland-dependent special status species. For this reason, E[x]ponent recommends that these stream crossings would be considered for additional mitigation measures to protect the whooping crane habitat of the RBWMD because of its importance as a stopover area for whooping crane feeding and resting.

e. While most whooping cranes stay within their migration corridor, they are seen outside the corridor on a regular basis and may have even begun prospecting new areas. Related to this point, many other special status species are capable of using new areas on a yearly basis. A further complication is that, according to the USGS, many water bird habitats within the RBWMD may be in a state of deterioration, and may already be compelling whooping cranes to use unprotected wetlands within the proposed Project. Therefore, E[x]ponent suggests that Keystone would conduct a bi-annual consultation with USFWS to identify areas of high potential for use by special status species and to update the proposed Project ERPs as appropriate.

f. Given the 50-year projected lifespan of the proposed Project and the possibility that one or more special status species may move into the Project vicinity during that timeframe, E[x]ponent concludes that the monitoring outlined in 49 CFR 195 may be insufficient to protect special status species over the lifespan of the Project. Specifically, E[x]ponent recommends that, in addition to monitoring physical factors that might impact pipeline integrity, Keystone develop a biological monitoring plan for these special and unique special status habitats to periodically determine whether T&E and other special status species are using these habitats within the Project area and whether they are afforded sufficient protection under the ERP.

23. Knowledge on the chemistry of dilbit continues to increase, and that new information should be incorporated into planning and operations as appropriate (e.g., to improve spill response planning).

24. Based on location-specific analyses of fate and effects of spills that Keystone would undertake prior to construction, Keystone should consider the use of additional valves and/or noninvasive boring technologies at the small stream crossings that E[x]ponent identified as associated with additional potentially sensitive ecological areas, and where Keystone's release analysis shows the potential exists for medium to very large spills.

25. Keystone should rely upon stream-specific scour analyses for small stream crossings to identify where the pipeline should be buried deeper than 5 feet or where horizontal

directional drilling may be warranted. The particular small stream crossings identified by E^{x}ponent should be given attention in this regard.

26. Both the likelihood (incident frequency) and the consequences were found to vary significantly between the discrete elements (e.g., stations, tanks, etc.) and lineal elements (e.g., pipeline, mainline valves, etc.) with large differences also evident between the system components and the facilities that comprise the discrete elements. Such results cast uncertainty on the use of aggregated metrics for risk, and equally cast uncertainty on the use of aggregated "professional engineering judgment," because the aggregation tends to mask potentially opposed trends. Accordingly, Keystone should assess risk at the level of these three elements, and use a rate other than a per-mile-year-average rate for the discrete elements.

27. Keystone should uncouple the currently coupled threats involving internal corrosion and external corrosion, and those involving material versus construction threats, unless statistically valid reasons are established to pool these data.

28. The model and the process that were used by Keystone in its previous risk analysis to ensure that valves are placed to minimize the total outflow from a breach appear to be correct and should continue to be used. Keystone will redo portions of the outflow analysis that reflect the proposed Project route.

29. Adopting the All Spills outcomes relative to those for other choices based on the General Cause categories in the PHMSA database could significantly underestimate the median spill volume relative to the environmental exposure along the pipeline right-of-way (ROW). Trending the cumulative distributions of spill volumes shows that the Keystone benchmark under-predicts the likelihood of larger spills except at the higher percentiles, where all trends converge. The results indicate that parsing on the Incorrect Operations, Natural Forces, Third-Party Damage (TPD), and Pipeline/Mainline Valve (MLV) General Cause categories lead to larger values for the median spill and at the 90th percentile. Accordingly, there is the potential for much larger spills than has been considered relative to the All Spills benchmark case. Because such trends represent a system-level analysis of historic incidents that typically involve much smaller diameter line pipe as compared to the proposed Project, there is the potential for still larger spills where unique site-specific threats exist along the ROW. Keystone's Risk Assessment should give consideration to a broader assessment of the environmental consequences relative to the probability of occurrence and spill volume, including the potential implications of pipe diameter. Spill analysis should focus on the threats associated with the major General Cause categories such as facilities, the pipeline, and its system components, which should present a clearer picture of the spill potential for the proposed Project. In turn, this should facilitate focusing the spill prevention, protection, and mitigation where it is most relevant.

30. To the extent practicable, future risk assessments should divide the pipeline system into component parts, assess the risk for each component, and then calculate the system risk from its components. The Battelle risk analysis shows that the subsystems that generate most of the risk are the mainline pipe and the fixed facilities such as the pumping stations. Thus, when developing preventive, protective, and mitigative programs, equal focus should be on the mainline pipe and the fixed facilities.

31. Naphthenic acids are a class of compounds found in crude oils (including Canadian oil sands) that can potentially result in aquatic toxicity if released into the environment; they have been the subject of significant research. Given the perceived link between tar sands processing and aquatic toxicity due to naphthenic acids, to the extent available, Keystone would obtain additional information on the naphthenic acid content of the oils to be transported.

32. Although PAH concentrations in petroleum are low compared to some environmental sources, this class of compounds can be a long-term driver for remediation and risk management following an oil spill. To the extent available, Keystone would obtain additional information on the chemistry of the oils as this information will be needed for developing cleanup and remediation plans. An understanding of the PAH profiles of pipeline oils would allow for differentiation between baseline and spill impacts.

33. Keystone, as part of the final Project design, should further evaluate overland flow (spreading analysis) of spilled oil, and further evaluate the transport of spilled oil in small streams (e.g., the downstream distance crude oil could travel from the proposed pipeline centerline) for purposes of the ERP. These analyses should take into account potential density and viscosity increases associated with the loss of volatiles from heavy crudes and diluted bitumen.

34. Keystone should use the screening criteria (e.g., well depth, depth of release compared to water table, lithology between pipeline and aquifer) suggested in [E^{x}ponent] report for identifying vulnerable/sensitive groundwater resources adjacent to the pipeline that do not classify as HCAs, but that may be more vulnerable to exposure to a benzene plume in the event of a an oil spill. For example, these could be defined as clusters of both domestic and irrigation wells within 1,000 feet of a pipeline segment where an oil spill could occur in or within a few feet of the water table. E^{x}ponent recommends that additional modeling be performed as part of the final Project design to further refine the appropriate downgradient distance criteria to be used for identifying sensitive clusters of wells. E^{x}ponent recommends that these non-HCA groundwater resources be afforded a degree of protection from the occurrence of an oil spill and from the consequences of a spill similar to what is currently afforded to groundwater resources that are defined HCAs.

35. It is recommended that Keystone use a distance of at least 10 miles downstream from the proposed pipeline centerline to identify sensitive areas and to identify contributory pipeline segments (CPSs) during the final Project design phase.[8]

4.0 ADDITIONAL MITIGATION MEASURES

Keystone has committed to a number of measures beyond the spill cleanup measures described above, including specifically addressing several issues in its Emergency Response Plan and Oil Spill Response Plan (and the detailed risk analysis used in developing those plans). These measures include:

1. Develop a plan for long term sampling/monitoring in the event of an oil discharge to assess and monitor these impacts as part of the spill response plan.

[8] Keystone has indicated that it uses a distance of 24 miles downstream per analysis provided by PHMSA Special Condition 14.

2. Include spill contingency plans in the Emergency Response Plan to address submerged oil, floating oil, and cold-weather responses.
3. Consider In detail locations to pre-position response assets, including equipment to address submerged oil, and actual pre-positioning of those assets.
4. Specify in the ERP that spill drills and exercises include strategies and equipment deployment to address floating and submerged oil.
5. Consult and communicate with the Local Emergency Response Planning Committees and other emergency service agencies during ERP development to ensure ERPs are aligned.
6. In the event that a spill affects a paleontological resource, prepare a paleontological mitigation plan to protect significant fossil resources.
7. In the event that a spill contaminates potable water supplies, be responsible for cleanup and restoration. Keystone would be responsible for providing an appropriate alternative potable water supply of comparable volume and quality to those impacted or provide compensation, if this option is agreed upon by the affected parties and Keystone. For groundwater used for industrial or irrigation purposes, Keystone may provide either an alternate supply of water or appropriate compensation for those facilities impacted, as may be agreed upon among the affected parties and Keystone. If the permit were approved, Keystone would memorialize that agreement through an appropriate written agreement with the Environmental Protection Agency.
8. File the following documents with Nebraska Department of Environmental Quality (NDEQ) by May 1 of each year:
    a. Certificate of insurance as evidence that it is carrying a minimum of $200 million in third-party liability insurance, with the NDEQ, as specified in the NDEQ’s December 2012 Final Evaluation Report, and with the Montana Department of Environmental Quality (MDEQ), as required by Keystone’s Certificate issued by MDEQ under the Montana Major Facility Siting Act (MFSA).
    b. Copy of Keystone’s Securities and Exchange Commission (SEC) Form 10-K and Annual Report. (Keystone’s MFSA Certificate contains a similar requirement.)
9. On request, file the documents listed in item 8 above with other appropriate state agencies.
10. Continue to assess the efficacy of implementing groundwater monitoring wells based on results of its risk assessments accounting for significant threats and in situ conditions. In-line leak inspection using Smart Ball, MFL, and UT would remain the primary focus of leak detection and integrity management. In the event of a release either inside or outside of an HCA, Keystone would consider the installation of groundwater monitoring wells to delineate the release extent and the threat to groundwater resources.
11. In the event of a release, provide the specific Material Safety Data Sheets (MSDSs) of the product(s) shipped (and released) to emergency responders (including any state, local, or federal agencies involved in spill response actions) within 1 hour of the release. Keystone would maintain a point of contact who would be authorized to release the MSDS and chemical composition information to first responders. The point of contact would be available (when a release occurs) for requests for MSDSs and to identify the composition of

the product (both crude and diluents) shipped in the pipeline. Keystone would establish a procedure for first responders to contact the point of contact with this hour timeframe.