APPENDIX B

PHMSA 57 Special Conditions for Keystone XL and Keystone Compared to 49 CFR 195

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PHMSA 57 SPECIAL CONDITIONS FOR KEYSTONE XL COMPARED TO 49 CFR 195

Condition	Keystone XL	49 CFR Part 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 API 5L standard, which does not require latest steel making properties.	These properties ensure high quality carbon steel which reduces chance of a pipeline release as compared with Part 195 requirement, thus increasing public safety.
2	**Manufacturing Standards:** Pipe carbon equivalents must be at or below 0.23% based on the material chemistry parameter, carbon equivalent (CE) (Pcm) formula (Ito-Bessyo formula) or 0.40% based on the C-IIW formula (International Institute of Welding formula).	Less prescriptive; references API 5L standard.	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, 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.	Less prescriptive; references API 5L standard.	Provides 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.

Condition	Keystone XL	49 CFR Part 195	Benefits
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 as affecting pipe quality. a) A mill inspection program or internal quality management program must include the following: i. Non-destructive test of the ends and at least 35 percent of the surface of the plate, coil or pipe shall be performed to identify imperfections such as laminations, cracks, and inclusions that may impair serviceability. 100 percent of the pipe sections must be tested. ii. A macro etch test or other equivalent method to identify inclusions that may form centerline segregation during the continuous casting process shall be performed. iii. A quality assurance monitoring program implemented by the operator. iv. 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 PHMSA Region Director(s), Central, Western, and Southwest Region, a histogram of end tolerance and wall thickness data representing physical evidence of compliance for a minimum of 10% of the pipe manufactured by each pipe mill facility. v. 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/field welds.	General, less prescriptive in Code Section 195.112 and references API 5L.	These properties ensure high quality carbon steel.
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.	General, less prescriptive in Code Section 195.112 and references API 5L.	These properties ensure welded seams (helical and straight) are equivalent strength to the pipe or stronger.

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6	**Monitoring for Seam Fatigue from Transportation:** Keystone must inspect weld seams of the delivered pipe using properly calibrated manual or automatic ultrasonic testing techniques. 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 results from a 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.	General, less prescriptive; no defined requirement.	Additional steel properties to resist external mechanical damage, which is the most common cause of pipeline failure.
8	**Mill Hydrostatic Test:** The pipe must be subjected to a mill hydrostatic test pressure of 95% specified minimum yield strength (SMYS) or greater for 10 seconds.	Sections 195.3 and 195.112.	Used to validate mainline pipe and seam integrity in the plant prior to final hydrotest in the 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.	Less prescriptive, Code Section 195.004 requires inspection.	Detailed application process requirements 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.	Provides personnel are trained and are aware of the requirements when applying field joint corrosion protection.
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.	Provides 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-II	Less prescriptive, Code Section 195.118 requires specifications, does not require	Provides pipeline materials are traceable for the life of the pipeline and weldable.

Condition	Keystone XL	49 CFR Part 195	Benefits
	W Formula (International Institute of Welding formula).	level of specificity.	
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 Maximum Operating Pressure (MOP) of the pipeline.	Less prescriptive, Code Section 195.118 requires specifications, does not require level of specificity.	Provides 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 six (6) months prior to beginning construction of the Keystone XL pipeline, Keystone must review with the appropriate PHMSA Regional Directors in Central, Western, and Southwest Regions how High Consequence Areas (HCA's) which could be affected, as defined in 49 CFR § 195.450, were determined (including 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 design of the pipeline associated with those segments. Keystone must identify piping and the design of piping located within pump stations, mainline valve assemblies, pigging facilities, measurement facilities, road crossings, railroad crossings, and segments operating immediately downstream and at lower elevations than a pump station. Keystone must also provide an overland spread analyses in accordance with § 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 fifteen (15) months, to identify changes on the pipeline system that would impact its designation or design.	Less prescriptive, Code Section 195.106 requires 0.72 design factor.	Provides regulatory oversight of design compliance to federal codes and standards and that encroachments near the pipeline such as urban development or new wellhead protection areas (WHPA) are factored into integrity management plans.
15	**Temperature Control:** Normal pump discharge temperatures should remain at or below 120° 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 integrity of the coating.	General, less prescriptive in Code Sections 195.400, 195.401, 195.402, 195.559, and 195.561.	Provides protective measures are in place for corrosion coating protection.

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16	**Overpressure Protection Control:** Keystone must limit mainline pipeline overpressure protection to a maximum of 110% maximum operating pressure (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 shall equip the pipeline with field devices that will stop the transit (intentional or uncommanded) of the mainline valve should an overpressure condition occur or an impending overpressure condition is 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 shall be installed along the pipeline to conduct real time hydraulic modeling, and which can be used to conduct a surge analysis to determine whether pipeline segments have experienced an overpressure condition.	Required in Section 195.406(b), but less prescriptive on surge analysis.	Provides additional assurance that overpressure protection measures are in place.
17	**Construction Plans and Schedule:** At least ninety (90) days prior to the anticipated construction start date, Keystone must submit its construction plans and schedule to the appropriate PHMSA Directors.	Part 195 Code does not require 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 shall use the 20th Edition of American Petroleum Institute 1104 (API 1104), "Welding of Pipelines and Related Facilities" for welding procedure qualification, welder qualification, and weld acceptance criteria. Keystone shall use the 20th Edition of API 1104 for other welding processes. Keystone shall nondestructively test girth welds in accordance with 49 CFR §§ 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% of each welder's girth welds made each day to be nondestructively tested.	This condition, and Keystone's normal practices, ensures that every weld is inspected.
19	**Depth of Cover:** Keystone shall construct the pipeline with soil cover at a minimum depth of forty-eight (48) inches in areas, except in consolidated rock. The minimum depth in consolidated rock areas is thirty-six (36) inches. Keystone shall maintain a depth of cover of 48 inches in cultivated areas and a depth of 42 inches in other areas. In cultivated areas where conditions prevent the maintenance of forty-eight (48) inches of cover, Keystone must employ additional protective measures to alert the public and excavators to the presence of the pipeline. The additional measures shall include: a) Placing warning tape and additional line-of-sight pipeline markers along the affected pipeline segment,	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.	Reduces the probability of mechanical damage through deeper pipeline burial. Requires depth of cover to be maintained at prescribed levels for life of pipeline.

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	b) In areas where threats from chisel plowing or other activities are threats to the pipeline, the top of the pipeline must be installed and maintained at least one foot below the deepest penetration above the pipeline, not to be less than 42-inches of cover. 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 six (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 ten (10) years, and replace cover as soon as practicable, not to exceed six (6) months, to meet the minimum depth of cover requirements specified herein.		
20	**Construction Tasks:** Keystone must prepare and follow an Operator Qualification (OQ) Program for construction tasks that can affect pipeline integrity. The Construction OQ 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. Girth welds must be inspected, repaired and non-destructively examined in accordance with 49 CFR §§ 195.228, 195.230, and 195.234. The NDE examiner must have required and current certifications.	General, less prescriptive. Construction personnel training, such as reading project specifications.	Provides that integrity of girth welds is examined by qualified individuals.
22	**Pressure Test Levels:** The pre-in service hydrostatic test must be to a pressure producing a hoop stress of a minimum 100% SMYS for mainline pipe and 1.39 times MOP for pump stations for eight (8) continuous hours. They hydrostatic test results from each test must be submitted in electronic format to the applicable PHMSA Director(s) in PHMSA Central, Western and Southwest Regions after completion of each pipeline.	Less prescriptive. Code Section 195.304 requires pressure test 1.25 times MOP for 4 hours and 1.1 times MOP for 4 hours.	Provides 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.	Provides no systemic issues are present should a pre-in-service hydrotest failure be experienced.

Condition	Keystone XL	49 CFR Part 195	Benefits
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.	Provides state-of-the-art monitoring and control of the pipeline.
25	**SCADA System – General**: a) Scan rate shall 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 National Transportation Safety Board (NTSB), Supervisory Control and Data Acquisition (SCADA) in Liquid Pipelines, Safety Study, NTSB/SS-05/02. c) Develop and implement shift change procedures for a controller that are scientifically based, sets 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 shall 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.	General, less prescriptive until late 2011 to 2013, when Control Room Management Rule (CRM), Code Section 195.446, is implemented. Most of these items are explicit in CRM or inferred in CRM.	Provides NTSB findings are included from previous pipeline failure investigations.
26	**SCADA – Alarm Management:** Alarm Management Policy and Procedures shall address: a) Alarm priorities determination. b) Controllers' authority and responsibility.	General, less prescriptive until late 2011 to 2013, when Control Room Management Rule (CRM), Code Section	Provides state of the art monitoring and control of the pipeline.

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	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 (AOCs). i) Combination AOCs or sequential alarms and events. j) Workload concerns. i. This alarm management policy and procedure review shall 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).	195.446, is implemented. Most of these items are explicit in CRM.	
27	**SCADA – Leak Detection System (LDS):** The LDS Plan shall include provisions for: a) Implementing applicable provisions in American Petroleum Institute Recommended Practice 1130, Computational Pipeline Monitoring for Liquid Pipelines, (API RP 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. Developing data validation plan (ensure input data to SCADA is valid) c) Defining lead detection criteria in the following areas: **i.** Providing redundancy plans for hardware and software and a periodic test requirement for equipment to be used live (also applies to SCADA equipment).	General, less prescriptive Code Section 195.134 and 195.444, not as detailed.	Provides state-of-the-art monitoring and control of the pipeline.
28	**SCADA – Pipeline Model and Simulator:** The Thermal-Hydraulic Pipeline Model / Simulator including pressure control system shall include a Model Validation / Verification Plan.	General, less prescriptive until late 2011 to 2013, when Control Room Management Rule (CRM) is implemented.	Provides state-of-the-art monitoring and control of the pipeline.
29	**SCADA – Training:** The training and qualification plan (including simulator training) for controllers shall: a) Emphasize procedures for detecting and mitigating leaks. b) Include a fatigue management plan and implementation of a shift	General, less prescriptive until late 2011 to 2013, when Control Room Management Rule (CRM) is implemented.	Provides state-of-the-art monitoring and control of the pipeline.

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	rotation schedule that minimizes possible fatigue concerns and is scientifically based, sets appropriate work and rest schedules, and consider 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 (5) times per year that allow controllers to provide feedback to the exercises, participate in exercise scenario development and be active participants in the exercise.		
30	**SCADA – Calibration and Maintenance:** The calibration and maintenance plan for the instrumentation and SCADA system shall be developed using guidance provided in American Petroleum Institute Recommended Practice 1130, Computational Pipeline Monitoring for Liquid Pipelines, (API RP 1130 1st Edition 2007). Instrumentation repairs shall be tracked and documentation provided regarding prioritization of these repairs. Controller log notes shall be periodically be reviewed for concerns regarding mechanical problems. This information shall be tracked and prioritized.	General, less prescriptive until late 2011 to 2013, when Control Room Management Rule (CRM) is implemented. Code Section 195.446(c) (2) will require conducting a point-to-point verification between SCADA displays and related field equipment when added or removed.	Provides state-of-the-art monitoring and control of the pipeline through fully functional SCADA system.
31	**SCADA – Leak Detection Manual:** The Leak Detection Manual shall 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 Code Sections 195.134 and 195.444 for leak detection which does reference API 1130.	Provides 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 shall locate valves in accordance with 49 CFR § 195.260 and by taking into consideration elevation, population, and environmentally sensitive locations, to minimize the consequences of a release from the pipeline. Mainline valves must be placed based on the analysis above or no more than twenty (20) miles apart, whichever is smaller. Mainline valves must	General Valve Requirements in Code Section 195.260.	Provides increased instrumentation feeding back data to reduce leak detection times, reduces potential spill volumes though prescriptive valve spacing, and ensures valves can close when loss of primary power is experienced.

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	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 too fast of a closure. 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 level of safety. For valves that cannot be remotely actuated, Keystone must document on a yearly basis not to exceed fifteen (15) months that personnel response time to these valves will not take over an hour.		Also ensures 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 in-line inspection (ILI) tools. [Keystone shall 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 can be internally inspected and requires direct assessment plan for pump stations and other facilities.

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34	**Internal Corrosion:** Keystone shall limit basic sediment and water (BS&W) to 0.5% by volume and report BS&W testing results to PHMSA in the annual report. Keystone shall 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 location 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 shall review the program at least quarterly based upon 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.	Provides management of internal corrosion threat during operations.
35	**Cathodic Protection:** The initial CP system must be operational within six (6) months of placing a pipeline segment in service.	Required in Code Sections 195.563–within one year.	Provides early management of external corrosion threat during operations.
36	**Interference Current Surveys:** Keystone must perform interference surveys over the entire Keystone XL pipeline within six months of placing the pipeline in service to ensure compliance with applicable NACE International Recommended Practices 0169 (2002 or the latest version incorporated by reference in §195.3) and 0177 (2007 or the latest version referenced thorough 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 shall determine if there have been adverse effects on the pipeline and mitigate such efforts as necessary.	Required in Code Sections 195.575 and 195.577–no timing guidelines.	Provides early management of external corrosion threat during operations.
37	**Corrosion Surveys:** Keystone must complete corrosion surveys within six (6) months of placing the respective CP system(s) in operation to ensure adequate external corrosion protection per NACE RP 0169. The survey shall also address the proper number and location of CP test stations as well as alternating current (AC) interference mitigation and AC grounding programs per NACE RP 0177. At least one (1) CP test station must be located within each HCA with a maximum spacing between test stations of	Required in Code Sections 195.571 and 195.573–timing of 2 years.	Provides early management of external corrosion threat during operations.

Condition	Keystone XL	49 CFR Part 195	Benefits
	one-half mile.		
38	**Initial Close Interval Survey (CIS):** A CIS must be performed on the pipeline within one 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 six (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 ICS to confirm cathodic protection systems are performing to protect the pipeline from corrosion.	Provides management of external corrosion threat during operations.
39	**Coating Condition Survey:** Keystone must perform a Direct Current Voltage Gradient (DCVG) survey or an Alternating Current Voltage Gradient (ACVG) survey within six (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.	Part 195 Code does not require operator to conduct coating surveys after the pipe has been backfilled and graded.	Provides 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 local restrictions. Additional markers must be placed along the pipeline in areas where the pipeline is buried less than forty-eight (48) inches. Keystone must replace removed or damaged line-of-sight markers, during pipeline patrols and maintenance on the right-of-way.	Required in Code Section 195.410, but does not require same level of markers or marker replacement program.	Reduces probability of mechanical damage threat and public awareness of high pressure utility.
41	**Pipeline Patrolling:** Patrol the right-of-way at intervals not exceeding three (3) weeks, but at least twenty-six (26) times each calendar year, to inspect for excavation activities, ground movement, unstable soil, wash outs, leakage, or other activities or conditions affecting the safety operation of the pipeline.	Required in Code Section 195.412, ROW patrols every 3 weeks and 26 times per year, but is less prescriptive on items to look for during surveys.	Reduces probability of mechanical damage threat, erosion control, and other threats.
42	**Initial ILI:** Within three (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 six (6) months after placing the pipeline in service.	Required in Code Section 195.452 within 5 years of placing in-service.	Provides early management of external and internal corrosion threat during operations.

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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.	Provides 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 close interval surveys (CIS) along the entire pipeline with current interrupted to confirm voltage drops in association with periodic ILI assessments under §195.452(j) (3). b) CIS must be conducted within three (3) months of running ILI surveys when using a five (5) year ILI frequency, not to exceed sixty-eight (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.	Provides enhanced management of external and internal corrosion threat during operations while overlapping data sets to cross check for issues.
45	**Verification of Reassessment Interval:** Keystone must submit a new fatigue analysis to validate the pipeline reassessment interval annually for the first five (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.	Provides enhanced management of fatigue threat during operations and review by PHMSA.
46	**Flaw Growth Assessment:** Two (2) years after the pipeline in-service date, Keystone shall use data gathered on 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 shall be performed by an independent party agreed upon by Keystone and PHMSA.	General, less prescriptive in Code Section 195.452, which requires reassessment intervals to be considered in high consequence areas.	Provides 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.	Provides enhanced management of corrosion threat during operation for non-piggable sections of piping inside facilities.

Condition	Keystone XL	49 CFR Part 195	Benefits
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.	Provides enhanced public awareness as part of damage control programs.
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%; d) Predicted metal loss is greater than 40% of nominal wall that is located at crossing of another pipeline and; i. Gouge or groove greater than 8% of nominal wall. e) Each anomaly not repaired under the immediate repair requirements must have a corrosion growth rate and ILI tool tolerance assigned per the Integrity Management Program (IMP) to determine the maximum re-inspection interval. f) 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 also use the most conservative method until confirmation of the proper method is made to PHMSA headquarters. g) Flow Stress: Remaining strength calculations for X-80 pipe must use a flow stress equal to the average of the ultimate (tensile) strength and SMYS.	General, less prescriptive. Required in Code Section 195.452, except Code does not require immediate repair when Failure Pressure Ratio is less than 1.16 (Code requires less than 1.0, which is less than Maximum Operating Pressure with no safety factor) and does not require 180-day repair if wall loss is less than 50%.	Provides timely investigation and prompt repair of anomalies in the pipeline reported via in-line inspection.

Condition	Keystone XL	49 CFR Part 195	Benefits
	h) Dents: For initial construction and the initial geometry tool run, Keystone must remove dents with a depth greater than two percent (2%) 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 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 Part 195, and shall notify the appropriate PHMSA regional office within twenty-four (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 shall report on its compliance with these conditions to the PHMSA Associate Administrator and the appropriate PHMSA Directors in Central, Western, and Southwest Region.	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. 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	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	49 CFR Part 195	Benefits
	k) Company mergers, acquisitions, transfers of assets, or other events affecting the regulatory responsibility of the company operating the pipeline.		
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.	Provides state-of-the-art integrity management practices are employed across entire pipeline system and risks are identified and plans developed.
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).	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 (MAOP) Rule, 80% SMYS.	Provides increased ROW 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 pipeline life.	Provides compliance records are maintained for the life of the pipeline.

Condition	Keystone XL	49 CFR Part 195	Benefits
56	**Certification:** A senior executive officer of Keystone must certify in writing the following: a) That Keystone has met the conditions described herein; b) That the written design, construction, and operating and maintenance (O&M) 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.	Provides Senior Management accountability and visibility to aspects of the project's design, construction and operations.
57	Within one (1) year of the in-service date, Keystone shall provide a detailed technical briefing, in person, to the appropriate PHMSA Directors in Central, Western, and Southwest Regions. The briefing shall 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 one-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.

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