DEPARTMENT OF TRANSPORTATION

PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION (PHMSA)

SPECIAL PERMIT

Docket Number:	PHMSA-2006-26617
Pipeline Operator:	TransCanada Keystone Pipeline, L.P.
Date Requested:	November 17, 2006
Code Section(s):	49 CFR 195.106

Grant of Special Permit:

Based on the findings set forth below, the Pipeline and Hazardous Materials Safety Administration (PHMSA) grants this special permit to TransCanada Keystone Pipeline, L.P. (Keystone). This special permit allows Keystone to design, construct and operate two new crude oil pipelines using a design factor and operating stress level of 80 percent of the steel pipe's specified minimum yield strength (SMYS) in rural areas. The current regulations in 49 CFR 195.106 limit the design factor and operating stress level for hazardous liquids pipelines to 72 percent of SMYS. This special permit is subject to the conditions set forth below.

Except for the non-covered portions of the pipelines described below, this special permit covers two proposed pipelines in the United States:

- The 1,025-mile, 30-inch, Mainline from the Canadian border at Cavalier County, North Dakota, traversing the States of South Dakota, Nebraska, Kansas and Missouri, to Wood River, Illinois; and

- The 291-mile, 36-inch, Cushing Extension from Jefferson County, Nebraska, through Kansas, to Cushing (Marion County), Oklahoma.

This special permit does not cover certain portions of the Mainline and Cushing Extension pipelines. These non-covered portions are the following:

- Pipeline segments operating in high consequence areas (HCAs) described as commercially navigable waterways in 49 CFR 195.450;

- Pipeline segments operating in HCAs described as high population areas in 49 CFR 195.450;

- Pipeline segments operating at highway, railroad and road crossings; and
- Piping located within pump stations, mainline valve assemblies, pigging facilities and measurement facilities.

For the purpose of this special permit, the "special permit area" means the area consisting of the entire pipeline right-of-way for those segments of the pipeline that will operate above 72 percent of SMYS.

Findings:

PHMSA finds that granting this special permit to Keystone to operate two new crude oil pipelines at a pressure corresponding to a hoop stress of up to 80 percent SMYS is not inconsistent with pipeline safety. Doing so will provide a level of safety equal to, or greater than, that which would be provided if the pipelines were operated under existing regulations. We do so because the special permit analysis shows the following:

- Keystone's special permit application describes actions for the life cycle of each proposed pipeline addressing pipe and material quality, construction quality control, pre-in service strength testing, the Supervisory Control and Data Acquisition (SCADA) system inclusive of leak detection, operations and maintenance and integrity management. The aggregate affect of these actions and PHMSA's conditions provide for more inspections and oversight than would occur on pipelines installed under existing regulations; and
- The conditions contained in this special permit grant require Keystone to more closely inspect and monitor the pipelines over its operational life than similar pipelines installed without a special permit.

Conditions:

The grant of this special permit is subject to the following conditions:

1) Steel Properties: The skelp/plate must be micro alloyed, fine grain, fully killed steel with calcium treatment and continuous casting.
2) Manufacturing Standards: The pipe must be manufactured according to American Petroleum Institute Specification 5L, *Specification for Line Pipe* (API 5L), product

specification level 2 (PSL 2), supplementary requirements (SR) for maximum operating pressures and minimum operating temperatures. Pipe carbon equivalents must be at or below 0.23 percent based on the material chemistry parameter (Pcm) formula.

3) Transportation Standards: The pipe delivered by rail car must be transported according to the API Recommended Practice 5L1, *Recommended Practice for Railroad Transportation of Line Pipe* (API 5L1).

4) Fracture Control: API 5L and other specifications and standards address the steel pipe toughness properties needed to resist crack initiation. Keystone must institute an overall fracture control plan addressing steel pipe properties necessary to resist crack initiation and propagation. The plan must include acceptable Charpy Impact and Drop Weight Tear Test values, which are measures of a steel pipeline's toughness and resistance to fracture. The fracture control plan, which must be submitted to PHMSA headquarters, must be in accordance with API 5L, Appendix F and must include the following tests:
   a) SR 5A - Fracture Toughness Testing for Shear Area: Test results must indicate at least 85 percent minimum average shear area for all X-70 heats and 80 percent minimum shear area for all X-80 heats with a minimum result of 80 percent shear area for any single test. The test results must also ensure a ductile fracture;
   b) SR 5B – Fracture Toughness Testing for Absorbed Energy; and
   c) SR 6 – Fracture Toughness Testing by Drop Weight Tear Test: Test results must be at least 80 percent of the average shear area for all heats with a minimum result of 60 percent of the shear area for any single test. The test results must also ensure a ductile fracture.

   The above fracture initiation, propagation and arrest plan must account for the entire range of pipeline operating temperatures, pressures and product compositions planned for the pipeline diameter, grade and operating stress levels, including maximum pressures and minimum temperatures for start up and shut down conditions associated with the special permit area. If the fracture control plan for the pipe in the special permit area does not meet these specifications, Keystone must submit to PHMSA headquarters an alternative plan providing an acceptable method to resist crack initiation, crack propagation and to arrest ductile fractures in the special permit area.

5) Steel Plate Quality Control: The steel mill and/or pipe rolling mill must incorporate a comprehensive plate/coil mill and pipe mill inspection program to check for defects and

inclusions that could affect the pipe quality. This program must include a plate or rolled pipe (body and all ends) ultrasonic testing (UT) inspection program per ASTM A578 to check for imperfections such as laminations. An inspection protocol for centerline segregation evaluation using a test method referred to as slab macro-etching must be employed to check for inclusions that may form as the steel plate cools after it has been cast. A minimum of one macro-etch or a suitable alternative test must be performed from the first or second heat (manufacturing run) of each sequence (approximately four heats) and graded on the Mannesmann scale or equivalent. Test results with a Mannesmann scale rating of one or two out of a possible five scale are acceptable.

6) Pipe Seam Quality Control: A quality assurance program must be instituted for pipe weld seams. The pipe weld seam tests must meet the minimum requirements for tensile strength in 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 two readings for each heat affected zone, two readings in the weld metal and two readings in each section of pipe base metal for a total of 10 readings. The pipe weld seam must be 100 percent UT inspected after expansion and hydrostatic testing per APL 5L.

7) Monitoring for Seam Fatigue from Transportation: Keystone must inspect the double submerged arc welded pipe seams of the delivered pipe using properly calibrated manual or automatic UT techniques. For each lay down 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. The entire longitudinal weld seam must be tested and the results appropriately documented. For helical seam submerged arc welded pipe, Keystone must test and document the weld seam in the area along the transportation bearing surfaces and all other exposed weld areas during the test. Each pipe section test record must be traceable to the pipe section tested. PHMSA headquarters must be notified of any flaws that exceeded specifications and needed to be removed. Keystone's findings will determine if PHMSA will require the testing program be expanded to include a larger sampling population for seam defects originating during pipeline transportation.

8) 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.

9) Mill Hydrostatic Test: The pipe must be subjected to a mill hydrostatic test pressure of 95 percent of SMYS or greater for 10 seconds. Any mill hydrostatic test failures must be reported to PHMSA headquarters with the reason for the test failure.

10) Pipe Coating: The application of a corrosion resistant coating to the steel pipe must be subject to a coating application quality control program. The program must address pipe surface cleanliness standards, blast cleaning, application temperature control, adhesion, cathodic disbondment, moisture permeation, bending, minimum coating thickness, coating imperfections and coating repair.

11) Field Coating: Keystone must implement a 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 must be implemented in field conditions. Field joint coatings must be non-shielding to cathodic protection (CP). Field coating applicators must use valid coating procedures and be trained to use these procedures. Keystone will perform follow-up tests on field-applied coating to confirm adequate adhesion to metal and mill coating.

12) Coatings for Trenchless Installation: Coatings used for directional bore, slick bore and other trenchless installation methods must resist abrasions and other damages that may occur due to rocks and other obstructions encountered in this installation technique.

13) Bends Quality: Certification records of factory induction bends and/or factory weld bends must be obtained and retained. All bends, flanges and fittings must have carbon equivalents (CE) equal to or below 0.42 or a pre-heat procedure must be applied prior to welding for CE above 0.42.

14) Fittings: All pressure rated fittings and components (including flanges, valves, gaskets, pressure vessels and pumps) must be rated for a pressure rating commensurate with the MOP of the pipeline.

15) Design Factor - Pipelines: Pipe installed under this special permit may use a 0.80 design factor. Pipe installed in pump stations, road crossings, railroad crossings, launcher/receiver fabrications, population HCAs and navigable waters must comply with the design factor in 49 CFR 195.106. If portions of the pipeline become population HCAs during the operational life of the pipeline, Keystone will apply to PHMSA headquarters for a special permit for the affected pipeline sections.
16) Temperature Control: The pipeline operating temperatures must be less than 150 degrees Fahrenheit.
17) Overpressure Protection Control: Mainline pipeline overpressure protection must be limited to a maximum of 110 percent MOP consistent with 49 CFR 195.406(b).
18) Construction Plans and Schedule: The construction plans, schedule and specifications must be submitted to the appropriate PHMSA regional office for review within two months of the anticipated construction start date. Subsequent plans and schedule revisions must also be submitted to the PHMSA regional office.
19) Welding Procedures: The appropriate PHMSA regional office must be notified within 14 days of the beginning of welding procedure qualification activities. Automated or manual welding procedure documentation must be submitted to the same PHMSA regional office for review. For X-80 pipe, Keystone must conform to revised procedures contained in the 20th edition of API Standard 1104, *Welding of Pipelines and Related Facilities* (API 1104), Appendix A, or by an alternative procedure approved by PHMSA headquarters.
20) Depth of Cover: The soil cover must be maintained at a minimum depth of 48 inches in all areas except consolidated rock. In areas where conditions prevent the maintenance of 42 inches of cover, Keystone must employ additional protective measures to alert the public and excavators to the presence of the pipeline. The additional measures shall include placing warning tape and additional pipeline markers along the affected pipeline segment. In areas where the pipeline is susceptible to threats from chisel plowing or other activities, the top of the pipeline must be installed at least one foot below the deepest penetration above the pipeline. If routine patrols indicate the possible loss of cover over the pipeline, Keystone must perform a depth of cover study and replace cover as necessary to meet the minimum depth of cover requirements specified herein. If the replacement of cover is impractical or not possible, Keystone must install other protective measures including warning tape and closely spaced signs.

21) Construction Quality: A construction quality assurance plan for quality standards and controls must be maintained throughout the construction phase with respect to: inspection, pipe hauling and stringing, field bending, welding, non-destructive examination (NDE) of girth welds, field joint coating, pipeline coating integrity tests, lowering of the pipeline in the ditch, padding materials to protect the pipeline, backfilling, alternating current (AC) interference mitigation and CP systems. All girth welds must be NDE by radiography or alternative means. The NDE examiner must have all current required certifications.

22) Interference Currents Control: Control of induced alternating current from parallel electric transmission lines and other interference issues that may affect the pipeline must be incorporated into the design of the pipeline and addressed during the construction phase. Issues identified and not originally addressed in the design phase must be brought to PHMSA headquarters' attention. An induced AC program to protect the pipeline from corrosion caused by stray currents must be in place and functioning within six months after placing the pipeline in service.

23) Test Level: The pre-in service hydrostatic test must be to a pressure producing a hoop stress of 100 percent SMYS and 1.25 X MOP in areas to operate to 80 percent SMYS. The hydrostatic test results from each test after completion of each pipeline must be submitted to PHMSA headquarters.

24) Assessment of Test Failures: Any pipe failure occurring during the pre-in service hydrostatic test must undergo a root cause failure analysis to include a metallurgical examination of the failed pipe. The results of this examination must preclude a systemic pipeline material issue and the results must be reported to PHMSA headquarters and the appropriate PHMSA regional office.

25) Supervisory Control and Data Acquisition (SCADA) System: A SCADA system to provide remote monitoring and control of the entire pipeline system must be employed.

26) 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, *Supervisory Control and Data Acquisition (SCADA) in Liquid Pipelines,* Safety Study, NTSB/SS-05/02 specifically including:

- Operator displays shall adhere to guidance provided in API Recommended Practice 1165, *Recommended Practice for Pipeline SCADA Display* (API RP 1165)
- Operators must have a policy for the review/audit of alarms for false alarm reduction and near miss or lessons learned criteria
- SCADA controller training shall include simulator for controller recognition of abnormal operating conditions, in particular leak events
- See item 27b below on fatigue management
- Install computer-based leak detection system on all lines unless an engineering analysis determines that such a system is not necessary

c) Develop and implement shift change procedures for controllers;

d) Verify point-to-point display screens and SCADA system inputs before placing the line in service;

e) Implement individual controller log-in provisions;

f) Establish and maintain a secure operating control room environment;

g) Establish controls to functionally test the pipeline in an off-line mode prior to beginning the line fill and placing the pipeline in service; and

h) Provide SCADA computer process load information tracking.

27) SCADA – Alarm Management: Alarm Management Policy and Procedures shall 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) Controllers' performance regarding alarm or event response;

h) Alarm indication of abnormal operating conditions (AOCs);

i) Combination AOCs or sequential alarms and events; and

j) Workload concerns.

28) SCADA – Leak Detection System (LDS): The LDS Plan shall include provisions for:

a) Implementing applicable provisions in API Recommended Practice 1130, *Computational Pipeline Monitoring for Liquid Pipelines* (API RP 1130), as appropriate;

b) Addressing the following leak detection system testing and validation issues:
   - Routine testing to ensure degradation has not affected functionality
   - Validation of the ability of the LDS to detect small leaks and modification of the LDS as necessary to enhance its accuracy to detect small leaks
   - Conduct a risk analysis of pipeline segments to identify additional actions that would enhance public safety or environmental protection
c) Developing data validation plan (ensure input data to SCADA is valid);
d) Defining leak detection criteria in the following areas:
   - Minimum size of leak to be detected regardless of pipeline operating conditions including slack and transient conditions
   - Leak location accuracy for various pipeline conditions
   - Response time for various pipeline conditions
e) Providing redundancy plans for hardware and software and a periodic test requirement for equipment to be used live (also applies to SCADA equipment).

29) SCADA – Pipeline Model and Simulator: The Thermal-Hydraulic Pipeline Model/ Simulator including pressure control system shall include a Model Validation/Verification Plan.

30) SCADA – Training: The training and qualification plan (including simulator training) for controllers shall:
   a) Emphasize procedures for detecting and mitigating leaks;
   b) Include a fatigue management plan and implementation of a shift rotation schedule that minimizes possible fatigue concerns;
   c) Define controller maximum hours of service limitations;
   d) Meet the requirements of regulations developed as a result of the guidance provided in the American Society of Mechanical Engineers Standard 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 near miss or lesson learned scenarios for training purposes;
   f) Implement tabletop exercises periodically that allow controllers to provide feedback to the exercises, participate in exercise scenario development and actively participate in the exercise;

g) Include field visits for controllers accompanied by field personnel who will respond to call-outs for that specific facility location;

h) Provide facility specifics in regard to the position certain equipment devices will default to upon power loss;

i) Include color blind and hearing provisions and testing if these are required to identify alarm priority or equipment status;

j) Training components for task specific abnormal operating conditions and generic abnormal operating conditions;

k) If controllers are required to respond to "800" calls, include a training program conveying proper procedures for responding to emergency calls, notification of other pipeline operators in the area when affecting a common pipeline corridor and education on the types of communications supplied to emergency responders and the public using API Recommended Practice 1162, *Public Awareness Programs for Pipeline Operators* (API RP 1162);

l) Implement on-the-job training component intervals established by performance review to include thorough documentation of all items covered during oral communication instruction; and

m) Implement a substantiated qualification program for re-qualification intervals addressing program requirements for circumstances resulting in disqualification, procedure documentation for maximum controller absences before a period of review, shadowing, retraining, and addressing interim performance verification measures between re-qualification intervals.

31) SCADA – Calibration and Maintenance: The calibration and maintenance plan for the instrumentation and SCADA system shall be developed using guidance provided in API 1130. Instrumentation repairs shall be tracked and documentation provided regarding prioritization of these repairs. Controller log notes shall periodically be reviewed for concerns regarding mechanical problems. This information will be tracked and prioritized.

32) SCADA – Leak Detection Manual: The Leak Detection Manual shall be prepared using guidance provided in Canadian Standards Association, *Oil and Gas Pipeline Systems*, CSA Z662-03, Annex E, Section E.5.2, Leak Detection Manual.

33) Mainline Valve Control: Mainline valves located on either side of a pipeline segment containing an HCA where personnel response time to the valve exceeds one hour must be

remotely controlled by the SCADA system. The SCADA system must be capable of opening and closing the valve and monitoring the valve position, upstream pressure and downstream pressure.

34) Pipeline Inspection: The pipeline must be capable of passing in line inspection (ILI) tools. All headers and other segments covered under this special permit that do not allow the passage of an ILI device must have a corrosion mitigation plan.

35) Internal Corrosion: Keystone shall limit sediment and water (S&W) to 0.5 percent by volume and report S&W testing results to PHMSA in the 180-day and annual reports. Keystone shall also report upset conditions causing S&W level excursions above the limit. This report shall also contain remedial measures Keystone has taken to prevent a recurrence of excursions above the S&W limits. Keystone must run cleaning pigs twice in the first full year of operation and as necessary in succeeding years based on the analysis of oil constituents, weight loss coupons located in areas with the greatest internal corrosion threat and other internal corrosion threats. Keystone will send their analyses and further actions, if any, to PHMSA.

36) Cathodic Protection (CP): The initial CP system must be operational within six months of placing a pipeline segment in service.

37) Interference Current Surveys: Interference surveys must be performed within six months of placing the pipeline in service to ensure compliance with applicable NACE International Standard Recommended Practices 0169 and 0177 (NACE RP 0169 and NACE RP 0177) for interference current levels. If interference currents are found, Keystone will determine if there have been any adverse affects to the pipeline and mitigate the affects as necessary. Keystone will report the results of any negative finding and the associated mitigative efforts to the appropriate PHMSA regional office.

38) Corrosion Surveys: Corrosion surveys of the affected pipeline must be completed within six months of placing the respective CP system(s) in operation to ensure adequate external corrosion protection per NACE RP 0169. The survey will also address the proper number and location of CP test stations as well as AC interference mitigation and AC grounding programs per NACE RP 0177. At least one CP test station must be located within each HCA with a maximum spacing between test stations of one-half mile within the HCA. If placement of a test station within an HCA is impractical, the test station must be placed at the nearest practical location. If any annual test station reading fails to meet 49 CFR 195,

Subpart H requirements, remedial actions must occur within six months. Remedial actions must include a close interval survey on each side of the affected test station and all modifications to the CP system necessary to ensure adequate external corrosion control.

39) Initial Close Interval Survey (CIS) - Initial: A CIS must be performed on the pipeline within two years of the pipeline in-service date. The CIS results must be integrated with the baseline ILI to determine whether further action is needed.

40) Pipeline Markers: Keystone must employ line-of-sight markings on the pipeline in the special permit area except in agricultural areas or large water crossings such as lakes where line of sight markers are impractical. The marking of pipelines is also subject to Federal Energy Regulatory Commission orders or environmental permits and local restrictions. Additional markers must be placed along the pipeline in areas where the pipeline is buried less than 42 inches.

41) Monitoring of Ground Movement: An effective monitoring/mitigation plan must be in place to monitor for and mitigate issues of unstable soil and ground movement.

42) Initial In-Line Inspection (ILI): Keystone must perform a baseline ILI in association with the construction of the pipeline using a high-resolution Magnetic Flux Leakage (MFL) tool to be completed within three years of placing a pipeline segment in service. The high-resolution MFL tool must be capable of gouge detection. Keystone must perform a baseline geometry tool run after completion of the hydrostatic strength test and backfill of the pipeline, but no later than six months after placing the pipeline in service under a special permit. The ILI data summary sheets and planned digs with associated ILI tool readings will be sent to the PHMSA regional office. The PHMSA regional office will be given at least 14 days notice before confirmation digs are executed on site. The dimensional data and other characteristics extracted from these digs will be shared with the PHMSA regional office. Keystone will also compare dimensional data and other characteristics extracted from the digs and compare them with ILI tool data. If there are large variations between dig data and ILI tool data, Keystone will submit PHMSA a plan on further actions, inclusive of more digs, to calibrate their analysis and remediation process.

43) Future ILI: Future ILI inspection must be performed on the entire pipeline subject to the special permit, on a frequency consistent with 49 CFR 195.452(j)(3), assessment intervals,

or on a frequency determined by fatigue studies based on actual operating conditions, inclusive of flaw and corrosion growth models.

44) Verification of Reassessment Interval: Keystone must submit a new fatigue analysis to validate the pipeline reassessment interval annually for the first five years after placing the pipeline subject to this special permit in service. The analysis must be performed on the segment experiencing the most severe historical pressure cycling conditions using actual pipeline pressure data.

45) Two years after the pipeline in-service date, Keystone will use all data gathered on pipeline section experiencing the most pressure cycles to determine effect on flaw growth that passed manufacturing standards and installation specifications. This study will be performed by an independent party agreed to by Keystone and PHMSA headquarters. Furthermore, this study will be shared with PHMSA headquarters as soon as practical after its completion, preferably before baseline assessment begins. These findings will determine if an ultrasonic crack detection tool must be launched in that pipeline section to confirm crack growth with Keystone's crack growth predictive models.

46) Direct Assessment Plan: Headers, mainline valve bypasses and other sections covered by this special permit that cannot accommodate ILI tools must be part of a Direct Assessment (DA) plan or other acceptable integrity monitoring method using External and Internal Corrosion Direct Assessment criteria (ECDA/ICDA).

47) Damage Prevention Program: The Common Ground Alliance (CGA) damage prevention best practices applicable to pipelines must be incorporated into the Keystone's damage prevention program.

48) Anomaly Evaluation and Repair: Anomaly evaluations and repairs in the special permit area must be performed based upon the following:
    a) Immediate Repair Conditions: Follow 195.452(h)(4)(i) except designate the calculated remaining strength failure pressure ratio (FPR) = < 1.16;
    b) 60-Day Conditions: No changes to 195.452(h)(4)(ii);
    c) 180-Day Conditions: Follow 195.452(H)(4)(iii) with exceptions for the following conditions which must be scheduled for repair within 180 days:
        - Calculated FPR = < 1.32
        - Areas of general corrosion with predicted metal loss greater than 40 percent

- Predicted metal loss is greater than 40 percent of nominal wall that is located at a crossing of another pipeline
- Gouge or groove greater than 8 percent of nominal wall

d) Each anomaly not repaired under the immediate repair requirements must have a corrosion growth rate and ILI tool tolerance assigned per the Integrity Management Program (IMP) to determine the maximum re-inspection interval.

e) Anomaly Assessment Methods: Keystone must confirm the remaining strength (R-STRENG) effective area, R-STRENG - 0.85dL and ASME B31G assessment methods are valid for the pipe diameter, wall thickness, grade, operating pressure, operating stress level and operating temperature. Keystone must also use the most conservative method until confirmation of the proper method 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 the ultimate (tensile) strength and the SMYS.

g) Dents: For initial construction and the initial geometry tool run, any dent with a depth greater than 2 percent of the nominal pipe diameter must be removed unless the dent is repaired by a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe. For the purposes of this condition, a "dent" is a depression that produces a gross disturbance in the curvature of the pipe wall without reducing the pipe wall thickness. The depth of the dent is measured as the gap between the lowest point of the dent and the prolongation of the original contour of the pipe.

49) Reporting - Immediate: Keystone must notify the appropriate PHMSA regional office within 24 hours of any non-reportable leaks originating in the pipe body in the special permit area.

50) Reporting – 180 Day: Within 180 days of the pipeline in-service date under a special permit, Keystone shall report on its compliance with special permit conditions to PHMSA headquarters and the appropriate regional office. The report must also include pipeline operating pressure data, including all pressures and pressure cycles versus time. The data format must include both raw data in a tabular format and a graphical format. Any alternative formats must be approved by PHMSA headquarters.

51) Annual Reporting: Following approval of the special permit, Keystone must annually report the following:

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

Limitations:

Should Keystone fail to comply with any conditions of this special permit, or should PHMSA determine this special permit is no longer appropriate or that this special permit is inconsistent with pipeline safety, PHMSA may revoke this special permit and require Keystone to comply with the regulatory requirements in 49 CFR 195.106.

Background and process:

The Keystone Pipeline is a 1,845-mile international and interstate crude oil pipeline project developed by TransCanada Keystone Pipeline L.P., a wholly owned subsidiary of TransCanada Pipelines Limited. The Keystone Pipeline will transport a nominal capacity of 435,000 barrels per day of crude oil from western Canada's sedimentary basin producing areas in Alberta to refineries in the United States. Keystone indicates it has filed an application with the U.S. Department of State for a Presidential Permit for the Keystone Pipeline since the project involves construction, operation and maintenance of facilities for the importation of petroleum from a foreign country. Keystone anticipates receiving all necessary government approvals by November 2007 and beginning construction in late 2007. The targeted in-service date is during the fourth quarter of 2009.

The existing regulations in 49 CFR 195.106 provide the method used by pipeline operators to establish the MOP of a proposed pipeline by using the design formula contained in that section. The formula incorporates a design factor, also called a de-rating factor, which is fixed at 0.72 for an onshore pipeline. Keystone requests the use of a 0.80 design factor in the formula instead of 0.72 design factor.

PHMSA previously granted waivers to four natural gas pipeline operators to operate certain pipelines at a hoop stresses up to 80 percent SMYS. The Keystone pipeline project represents the first request by an operator in the United States for approval to design and operate a hazardous liquid (crude oil) pipeline beyond the existing regulatory maximum level. Canadian standards already allow operators to design and operate hazardous liquids pipelines at 80 percent SMYS.

On January 15, March 27, and April 17, 2006, PHMSA conducted technical meetings to learn more about the technical merits of Keystone's proposal to operate at 80 percent SMYS and to answer questions posed by internal and external subject matter experts. The meetings resulted in numerous technical information requests and deliverables, to which Keystone satisfactorily responded.

PHMSA also secured the services of experts in the field of steel pipeline fracture mechanics, leak detection and SCADA systems to assist in the review of appropriate areas of Keystone's application. The experts' reports are included in the public docket.

On February 8, 2007, PHMSA posted a notice of this special permit request in the Federal Register (FR) (72 FR 6042). In the same FR notice we informed the public that we have changed the name granting such a request to a special permit. The request letter, the FR notice, supplemental information and all other pertinent documents are available for review under Docket Number PHMSA-2006-26617, in the DOT's Document Management System.

Two comments were received and posted to the public docket concerning the Keystone pipeline project request for a special permit. One commenter listed a number of recommended and relevant conditions for hazardous liquid pipelines to operate at 80 percent SMYS. The conditions developed by PHMSA and incorporated into the grant of special permit include the concerns of the commenter. The second commenter did not provide substantive comments relevant to the special permit request.

AUTHORITY: 49 U.S.C. 60118(c) and 49 CFR 1.53.

Issued in Washington, DC on APR 30 2007.

Jeffrey D. Wiese,

Acting Associate Administrator for Pipeline Safety.