U.S. Department of Transportation
Pipeline and Hazardous Materials
Safety Administration

1200 New Jersey Ave, S.E.
Washington, D.C. 20590

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

Mr. M. Dwayne Burton
Vice President, Operations and Engineering
Midcontinent Express Pipeline, LLC
One Allen Center
500 Dallas St
Suite 1000
Houston, TX 77002

RE: Midcontinent Express Pipeline, LLC (MEP); Special Permit: PHMSA-2007-27842

Dear Mr. Burton:

On August 25, 2009, you wrote to the Pipeline and Hazardous Materials Safety Administration (PHMSA) requesting to increase the operating pressure of the Midcontinent Express Pipeline, LLC (MEP) to a pressure corresponding to a maximum hoop stress of 80% of the specified minimum yield strength (SMYS) in accordance with the alternative maximum allowable operating pressure (MAOP) Special Permit, Docket No. PHMSA-2007-27842. MEP currently operates at a pressure corresponding to 72% SMYS. Further, under separate cover, MEP submitted documents supporting the request.

After a thorough review of the documents and consideration of MEP assertions in your August 25, 2009 letter, this letter responds to your request, providing guidance to attain operating pressures above 72% SMYS up to 80% SMYS. The requirements contained herein in "Attachment A"– Integrity Verification of Pipe Properties – September 1, 2009 apply to the pipeline segments experiencing expansion above 0.60% for 42-inch pipe and 0.75% for pipe equal to or less than 36-inch diameter.

On May 21, 2009, PHMSA issued an advisory bulletin (PHMSA-2009-0148), for the Potential for Low and Variable Yield and Tensile Strength and Chemical Compositions in High Strength Line Pipe (ADB), recommending operators to investigate if certain pipelines contain pipe joints not meeting minimum specification requirements (74 FR 23930). The observance of pipe expansions on recently constructed natural gas projects including Kinder Morgan projects led to PHMSA's issuance of the ADB. PHMSA remains concerned about expansion deformations exceeding 1.5% and is particularly concerned with any situation where expansion is present in combination with pipe not meeting mechanical requirements under API 5L. In fact, the basis for the design formula contained in 49 CFR section 192.111 contains specific material property requirements which provides the basis for establishing MAOP under 49 CFR section 192.619.

Therefore, an operator cannot afford to only consider the amount of expansion when reviewing pipeline in-line inspection deformation tool results since expansion may also be evidence of low yield or tensile strength line pipe. Until further studies are complete, PHMSA believes that a conservative approach is necessary that requires the operator to remove excessive pipe expansion anomalies along with performing mechanical testing to confirm if yield strength is a concern. To this end, PHMSA requests MEP to confirm if the following interim guidelines in "Attachment A – Integrity Verification of Pipe Properties" dated September 1, 2009 were met for the MEP pipeline.

MEP must implement all special permit conditions in PHMSA-2007-27842, for the special permit pipeline segments. All DCVG/ACVG surveys must be conducted in accordance with the special permit conditions. The DCVG/ACVG surveys and the pipe coating remediation must be completed within 6 months after operating at the alternative MAOP (above 72% SMYS up to 80% SMYS operating pressure).

Contingent upon your certification and documentation of compliance with the attached interim guidelines, PHMSA will grant authorization to increase the operating pressure of the designated MEP pipeline to a pressure corresponding to 80% SMYS. Please be advised that the interim guidelines covered in the attached document Attachment A – Integrity Verification of Pipe Properties" dated September 1, 2009 are subject to change as new integrity information is acquired through pipe properties testing and research from this and other projects.

Sincerely,

Alan K. Mayberry, P.E.
Director, Engineering and Emergency Support
Office of Pipeline Safety

Cc: Jeffrey Wiese
John Gale
Linda Daugherty
Steve Nanney
Rod Seeley

"ATTACHMENT A"– Integrity Verification of Pipe Properties – September 1, 2009

MEP must remove all pipe joints expanded in excess of 1.50% in diameter, with elastic loading included (i.e., taking into account the pressure on the pipe at the time of measuring the deformation), or the commensurate adjusted expansion without elastic loading on the pipe when expansion is verified in the field without pressure on the pipe.

MEP must also comply with the following requirements prior to operation of Class 1 pipe above 72% specified minimum yield strength (SMYS):

1) Unless already completed, MEP must run a deformation tool through all pipeline segments on the MEP Pipeline. MEP must use a high resolution deformation tool in lieu of a geometry tool to address the threat of low strength, expanded pipe.
    a. The deformation tool must include multi-finger sensors that contact the pipe internal diameter and have an accuracy of +/- 1% or less to identify expanded pipe and dents. The results of all deformation tool run results for expanded pipe and dents should be analyzed and submitted to the appropriate PHMSA Regional Director. All pipe exhibiting an indicated diameter greater than 0.60 % or 0.75% (based upon pipe diameter 42" or ≥ 36" per API 5L) above the nominal pipe diameter should be noted on the report of potential deformations. Expanded pipe is defined as pipe exhibiting an indicated diameter greater than 0.60 % or 0.75% (based upon pipe diameter 42" or ≥ 36" per API 5L) above the nominal or actual rolled pipe diameter.
    b. MEP must ensure that all deformation tool results are not masked by the approach used to calculate and compare expanded versus non-expanded pipe and the percentage of expansion. MEP must employ procedures to review and compare deformation tool results with other pipe joint diameters to ensure an entire pipe joint is not expanded.
    c. MEP must review with the appropriate PHMSA Regional Director, the deformation tool reports. This analysis must consider pipe properties and property distributions, hydrostatic test pressures and reported test behavior, and pipe end to center variations. Based on local pressure and expected behavior, any expansion exceeding the diameter by more than 1.5% with elastic loading (or the commensurate adjusted expansion with elastic loading on the pipe, when expansion is verified in the field without pressure on the pipe) must be investigated by excavation to determine actual expansion, wall thinning and, if necessary, to verify pipeline special permit segments: tensile strength, yield strength, elongation, chemical composition, carbon equivalent/Pcm, hardness, Charpy – shear area and absorbed energy with full Charpy curves, and drop weight tear test (DWTT) properties ("properties test").

2. Pipe joints with expansions ≥ 1.5 % with elastic loading must be removed and confirmed for strength serviceability as follows:
   a. Perform "properties test" in the transverse direction. MEP must take 2 sets at 3 locations along the pipe section of "properties test" for each removed pipe joint. The expanded pipe joint should be mapped to identify expanded pipe minimum and maximum wall thicknesses with at least 10 thickness readings mapped showing location on the pipe.,
   b. If expanded pipe properties tests in (a.) do not meet special permit requirements, MEP must:
      i. Perform "properties test" of at least two (2) expanded pipe joints over 1% with elastic loading and two (2) non-expanded pipe samples from the steel/pipe supplier of expanded pipe (same OD, wall thickness, Grade, weld seam, steel supplier, pipe manufacturer and rolling campaign) to confirm pipe properties. The non-expanded pipe joints may be from in service or spare pipe inventory.
      ii. Submit remediation plans or a technical justification (fitness for service plan) to PHMSA on how reduced strength pipe meets 49 CFR Part 192.105.
   c. If the deformation tool run in Condition 1 shows no expanded pipe above 1.5% expansion or the pipe "properties test" in Condition 2. b above shows no reduced pipe properties, MEP must excavate two (2) expanded pipe joints with expansion above 1% with elastic loading to determine if there is wall loss or thinning that is detrimental to safe operations, prior to operating at the alternative MAOP. Any wall loss that would reduce the pipe segment operating pressure in accordance with §§ 192.103, 192.105 192.111, 192.112 and 192.619 must be remediated. If these excavations show wall loss below nominal wall thickness, MEP must continue to excavate and remediate expanded pipe joints above 1% with elastic loading until there are no detrimental wall loss pipe joints in service.
3. All deformation tool results, for an initial run on a "pipeline segment", must be confirmed with at least two calibration digs to validate anomaly sizes and tool accuracy. Tool inaccuracies after validation must be considered into expanded pipe evaluations and remediation.
4. MEP must not use the "one class bump" for class change locations where expansions exceeded 1.0% with elastic loading until completion of a "fitness for service" plan and acceptance by PHMSA.
5. The interim guidelines contained herein must be reviewed with PHMSA, Director of Engineering and Emergency Support and PHMSA, Southern and Southwestern Regional Directors at the completion of the investigation, pipe properties testing, and "fitness for service" plan for technical soundness (including a determination of the proper pipe grade to meet § § 192.103, 192.105, 192.111, 192.112 and 192.619 in determining the alternative MAOP or MAOP of the pipeline segment)

MEP must perform the following actions where deformation tool runs indicate expansion greater than 1.5 % or in pipeline segments with low strength pipe.

6. Conduct a re-inspection and remediation of the pipelines with deformation and high resolution magnetic flux leakage (MFL) tools to evaluate for metal loss and expansion anomalies:
    a. Within 36 months of operating above 72% SMYS up to 80% SMYS on any given pipeline segment with expanded or remediated pipe.
    b. Schedule subsequent in-line inspection with MFL tools (ILI) and close interval survey re-inspections for the pipelines based on failure pressure ratios (FPRs) calculated after the first re-inspection, but not to exceed 5 year intervals.
    c. Manage plain dents (in accordance with ANSI B31.8 and § 192.933) not to exceed 6% total strain in pipe body and 2% strain contiguous with weld for future ILI deformation and geometry tool runs.
7. Pipeline operations: Pipeline may be operated up to the alternative MAOP (80% SMYS), after successful completion of the following interim guidelines:
        i. "Properties tests," and a technical review including review of pipe test pressures to confirm that pipe property results meet API 5L specifications and 49 CFR Part 192 requirements for the alternative MAOP or MAOP. The "properties tests" must show conformance with API 5L and alternate MAOP or MAOP criteria.
        ii. "Fitness for service" plan review outlining how integrity threats to the pipeline would be treated to operate at the alternate MAOP or MAOP, based upon pipe "properties test" and any effects of elevated test pressure due to pipe elevation differences may have had on pipe expansion.
        iii. The technical documentation of all "properties test" findings or "fitness for service" plans must be submitted by MEP to PHMSA, Director of Engineering & Emergency Support and the PHMSA, Southern and Southwestern Regional Directors for review. PHMSA must approve all submittals prior to implementation of alternative MAOP; any operating pressures above 72% SMYS.
    b. For pipeline operations, MEP must run:
        i. ILI initially within 3 years of operating at the alternative MAOP and on a maximum 5 year interval thereafter. Anomalies must be evaluated and remediated based upon alternative MAOP or MAOP conditions,
        ii. Conduct close interval surveys (CIS) and remediate pipe in each pipeline segment in accordance with 49 CFR Part 192 on a periodic basis, not to exceed 3 months of running ILI tools.
        iii. MEP must operate in accordance with the "interim guidelines of this document" until PHMSA has developed "go-forward" guidance on expanded pipe removals based upon technical input from research and industry. If the PHMSA technical and safety evaluation of pipe expansion issues results in "go-forward" guidance that differs from the requirements above, MEP must implement the PHMSA "go-

forward" guidance for the alternative MAOP or MAOP ***pipeline segments***.

8. For expanded pipe only not meeting 49 CFR Part 192.105 and special permit requirements, implement enhanced corrosion anomaly response and repair criteria:
   a. Anomaly Response Time: Repair Immediately
      - Any anomaly within a ***pipeline segment*** operating up to 80% SMYS with either: (1) a failure pressure ratio (FPR) equal to or less than 1.15; (2) an anomaly depth equal to or greater than 50% wall thickness loss.
      - Any anomaly within a ***pipeline segment*** operating up to 72% SMYS with either: (1) a failure pressure ratio (FPR) equal to or less than 1.25; (2) an anomaly depth equal to or greater than 50% wall thickness loss.
      - Any anomaly within a ***pipeline segment*** operating up to 60% SMYS with either: (1) an FPR equal to or less than 1.40; (2) an anomaly depth equal to or greater than 50% wall thickness loss.
      - Any anomaly within a ***pipeline segment*** operating up to 50% SMYS with either: (1) an FPR equal to or less than 1.5; (2) an anomaly depth equal to or greater than 50% wall thickness loss.
   b. Anomaly Response Time: Repair Within One Year
      - Any anomaly within a ***pipeline segment*** operating at up to 80% SMYS with either: (1) an FPR equal to or less than 1.25; (2) an anomaly depth equal to or greater than 40% wall thickness loss.
      - Any anomaly within a ***pipeline segment*** operating at up to 72% SMYS with either: (1) an FPR equal to or less than 1.39; (2) an anomaly depth equal to or greater than 40% wall thickness loss.
      - Any anomaly within a ***pipeline segment*** operating at up to 60% SMYS with either: (1) an FPR equal to or less than 1.67; (2) an anomaly depth equal to or greater than 40% wall thickness loss.
      - Any anomaly within a ***pipeline segment*** operating at up 50% SMYS with either: (1) an FPR equal to or less than 2.0; (2) an anomaly depth equal to or greater than 40% wall thickness loss.
   c. Anomaly Assessment Methods:
      - MEP must use the most conservative anomaly repair method and take into account the lowest pipe properties for all pipe in a "category" when evaluating an anomaly. "Category" is based upon diameter, class location, steel source, pipe manufacturer, wall thickness, and grade.
9. MEP must review and document all areas along the pipeline to ensure pipe loadings at all crossings meet combined stress limits for all equipment, farm machinery, roads, highways, and railroads to maintain Special Permit design factors based upon the lowest pipe strengths for that pipe grade, wall thickness, design factor, maximum loadings, and depth of cover. MEP must add a provision in its Operations and Maintenance Manual for annual reviews to account for combined stresses.
10. MEP's Operations and Maintenance Procedures must include the interim guidelines of this document within three months of operating at the alternative MAOP. Submit and must be certified by an officer of MEP to the PHMSA, Director of Engineering and Emergency Support and the PHMSA Southern and Southwestern Regional Directors.

U.S. DEPARTMENT OF TRANSPORTATION

PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION (PHMSA)

SPECIAL PERMIT

Docket Number:	PHMSA-2007-27842
Requested By:	Midcontinent Express Pipeline, LLC
Date Requested:	April 4, 2007
Code Sections:	49 CFR §§ 192.111 and 201

Grant of Special Permit:

The Pipeline and Hazardous Materials Safety Administration (PHMSA) grants this special permit to the Midcontinent Express Pipeline, LLC (MEP), subject to the conditions and limitations set forth below, waiving compliance from 49 CFR §§ 192.111 and 192.201 for a proposed 500-mile interstate natural gas transmission pipeline to be operated by MEP, a jointly owned subsidiary of Kinder Morgan Energy Partners, L.P. and Energy Transfer Partners L.P. The new pipeline will consist of approximately 40 miles of 30-inch diameter and 257 miles of 42-inch diameter pipeline in "Zone 1" and approximately 197 miles of 36-inch diameter pipeline in "Zone 2." The pipeline will originate in Bryan County, Oklahoma and run southeasterly through Texas, Louisiana and Mississippi to existing facilities in Choctaw County, Alabama.

This special permit allows MEP to design, construct and operate the MEP pipeline in Class 1 locations only using a design factor in § 192.111 up to 0.80 and at stress levels up to 80% of the specified minimum yield strength (SMYS). This would result in a maximum allowable operating pressure (MAOP) of 1,480 pounds per square inch gauge (psig) for the 42-inch and 36-inch segments and 1,440 psig for the 30-inch segment.

This special permit also allows MEP to design, install and operate pressure relief and limiting devices on the MEP pipeline with a capacity that would ensure the pressure in Class 1 location pipeline segments would not exceed 104% of the MAOP or the pressure that produces a hoop stress of 83.2% SMYS in the event an overpressure situation develops. The pipeline overpressure criteria in Class 2 and 3 locations must conform to existing regulations.

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% SMYS in Class 1 locations.

PHMSA grants this special permit based on the findings set forth in the *"Special Permit Analysis and Findings"* document, which can be read in its entirety in Docket No. PHMSA-2007-27842 in the Federal Docket Management System (FDMS) located on the Internet at www.Regulations.gov.

Conditions

PHMSA grants this special permit 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% based on the material chemistry parameter (Pcm) formula.
3) Fracture Control: API 5L, the American Society of Mechanical Engineers B31.8 Standard (ASME B31.8) and other specifications and standards address 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. MEP must institute an overall fracture control plan addressing steel pipe properties necessary to resist crack initiation and crack propagation and to arrest a fracture within 8 pipe joints with a 99% occurrence probability or within 5 pipe joints with a 90% occurrence probability. 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% minimum average shear area for all X- 70 heats and 80% minimum shear area for all X- 80 heats with a minimum result of 80% shear area for any single test. The test

results must also ensure a ductile fracture and arrest;

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% of the average shear area for all heats with a minimum result of 60% of the shear area for any single test. The test results must also ensure a ductile fracture and arrest.

The above fracture initiation, propagation and arrest plan must account for the entire range of pipeline operating temperatures, pressures and gas compositions planned for the pipeline diameter, grade and operating stress levels, including maximum pressures and minimum temperatures for shut-in conditions associated with the *special permit area*. Where the use of stress factors, pipe grade, operating temperatures and gas composition make fracture toughness calculations non-conservative, correction factors must be used. If the fracture control plan for the pipe in the *special permit area* does not meet these specifications, MEP 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*.

4) 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 ultrasonic testing (UT) inspection program to check for imperfections such as laminations. UT inspection must be conducted on all factory beveled pipe ends. In addition, pipe body UT inspection must be conducted on a minimum of 100% of pipe joints and all ends, with a minimum coverage of 35% of the pipe body for those joints inspected. Any laminations identified by the UT inspection program must be evaluated in accordance with the acceptance criteria defined in ASTM International Standard ASTM A578/A578M "*Standard Specification for Straight-Beam Ultrasonic Examination of Rolled Steel Plates for Special Applications (ASTM A578),*" Level B or API 5L Paragraph 7.8.10. 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 4 heats) and graded on the Mannesmann scale or equivalent. Test results with a Mannesmann scale rating of one or two out of a possible four or five scale are acceptable.

5) 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 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% UT inspected after expansion and hydrostatic testing per API 5L.

6) Mill Hydrostatic Test: The pipe must be subjected to a mill hydrostatic test to achieve a minimum stress level of 95% SMYS in the pipe for a minimum duration of 10 seconds. The 95% 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, Appendix K.

7) 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.

8) Field Coating: 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.

9) 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.

10) 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) below 0.42 or a pre-heat procedure must be applied prior to welding for CE above 0.42.

11) Fittings: All pressure rated fittings and components (including flanges, valves, gaskets, pressure vessels and compressors) must be rated for a pressure rating commensurate with the MAOP and class location of the pipeline. Designed fittings (including tees, elbows and caps) must have the same design factor as the adjacent pipe.

12) Design Factor - Pipelines: Pipe installed under this special permit in Class 1 location may use a design factor of 0.80.

13) Temperature Control: The compressor station discharge temperature must be limited to 120° Fahrenheit. A temperature above this maximum temperature of 120° Fahrenheit may be approved if MEP technical coating operating tests show that the pipe coating will properly withstand the higher operating temperature for long term operations. If the temperature exceeds 120° Fahrenheit MEP must also institute 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. This program will be approved by and results provided to the regional offices of PHMSA where the pipe is in service.

14) Overpressure Protection Control: Mainline pipeline overpressure protection must be limited to a maximum of 104% MAOP.

15) Welding Procedures: For automatic or mechanized welding the 20th Edition, of API 1104, "*Welding of Pipelines and Related Facilities,*" will be used for welding procedure qualification, welder qualification and weld acceptance criteria. Operator must use the 19th Edition of API 1104 for all other welding processes. 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.

16) Depth of Cover: The soil cover must be a minimum depth of 36 inches in all areas. In areas where threats from chisel plowing or other activities are threats to the pipeline, the top of the pipeline must be installed at least one foot below the deepest penetration above

the pipeline. If routine patrols or other observed conditions indicate the possible loss of cover over the pipeline, MEP will perform a depth of cover study and replace cover as necessary to meet the minimum depth of cover requirements specified herein.

17) Construction Quality: A construction quality assurance plan to ensure 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 non-destructively examined by radiography or alternative means. The NDE examiner must have all required and current certifications.

18) 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 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's attention by notifying the appropriate regional office. An induced AC program to protect the pipeline from corrosion caused by stray currents must be in place within six months after placing the pipeline in service.

19) Test Level: The pre-in service hydrostatic test must be to a pressure producing a hoop stress of at least 100% SMYS and 1.25 X MAOP in areas to operate to 80% SMYS. Short segments of pipe (up to one mile in length) having a design factor between 72% SMYS and less than 80% SMYS may be tested with 80% SMYS pipe provided the test pressure produces a hoop stress of at least 1.25 X MAOP for all pipe tested.

20) 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.

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

22) SCADA Procedures: A detailed procedure for establishing and maintaining accurate

SCADA set points must be established to ensure the pipeline operates within acceptable design limits at all times.

23) Mainline Valve Control: Mainline valves located on either side of a pipeline segment containing a High Consequence Area (HCA) where personnel response time to the valve exceeds one hour must be remotely controlled via the SCADA system. The SCADA system must be capable of closing these mainline valves and monitoring the valve position, as well as upstream pressure and downstream pressure at the mainline valve. As an alternative, a leak detection system for mainline valve control is acceptable.

24) 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.

25) Gas Quality Monitoring: An acceptable gas quality monitoring and mitigation program must be instituted to not exceed the following limits:
    a) H_2S (1.0 grain per 100 standard cubic feet or 16 parts per million (ppm), maximum);
    b) CO_2 (3% maximum);
    c) H_2O (less than or equal to 7 pounds per million standard cubic feet and no free water); and
    d) Other deleterious constituents that may impact the integrity of the pipeline.

26) The pipeline must have an ongoing pigging and liquids sampling plan to identify, mitigate and remove deleterious constituents where applicable.

27) If H_2S is above 8 ppm up to a maximum of 16 ppm, the gas stream constituents must be reviewed for implementation of a quarterly pigging/inhibitor injection program, including follow up sampling of liquids at receipt points.

28) Gas Quality Control: Separators or Filters/separators must be installed at locations where gas is received into the pipeline where the incoming gas stream quality includes potentially deleterious free liquids and/or particulates to minimize the entry of contaminants and to protect the integrity of downstream pipeline segments.

29) Gas Quality Monitoring Equipment: Equipment, including moisture analyzer, chromatograph and semi-annual H_2S sampling (quarterly sampling where H_2S is above 8 ppm), must be installed to permit the operator to manage and limit the introduction of contaminants and free liquids into the pipeline.

30) Cathodic Protection: The initial CP system must be operational within 12 months of placing any pipeline segment in service.

31) 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, MEP will determine if there have been any adverse affects to the pipeline and mitigate the affects as necessary. MEP will report the results of any negative finding and the associated mitigative efforts to the appropriate PHMSA regional office.

32) 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.

33) Verification of Cathodic Protection: An interrupted close interval survey (CIS) must be performed in concert and integrated with ILI in accordance with 49 CFR Part 192 Subpart O reassessment intervals for all HCA pipeline mileage. At least one CP test station must be located within each HCA with a maximum spacing between test stations of one-half mile within an HCA. If any annual test station reading fails to meet 49 CFR Part 192, Subpart I requirements, remedial actions must occur within six months. Remedial actions must include a CIS on each side of the affected test station and all modifications to the CP system necessary to ensure adequate external corrosion control.

34) 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.

35) Initial Coating Assessment – MEP must assess the integrity of the pipeline coating after completion of padding and backfill during construction through use of coating indirect assessment methods such as DCVG or ACVG surveys or equivalent methods. MEP must remediate any damaged coating found during these assessments that are classified as minor and at or above 15% IR for DCVG or at or above 30 dBμV for ACVG, moderate or severe based on NACE International Recommended Practice 0502-2002, *Pipeline External*

Corrosion Direct Assessment Methodology, (NACE RP 0502-2002). A minimum of two coating survey assessment classifications must be excavated, classified and/or remediated per each survey crew and compressor station discharge pipeline section to verify survey results.

36) Pipeline Markers: MEP 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 not practical. The marking of pipelines is also subject to Federal Energy Regulatory Commission orders or environmental permits and local restrictions.

37) Pipeline Patrolling: Pipeline patrolling must be conducted at least monthly (12 times per calendar year), not to exceed 45 days, to inspect for excavation activities, ground movement, wash-outs, leakage or other activities and conditions affecting the safe operation of the pipeline.

38) 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.

39) Initial ILI: MEP 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. MEP must perform a baseline geometry tool run after completion of the hydrostatic strength test and backfill of the pipeline, (just prior to placing the pipeline in service) but no later than six months after placing the pipeline in service in accordance with the conditions allowed by the special permit.

40) Future ILI: A second high-resolution MFL inspection must be performed and completed on the pipe subject to this special permit within the first reassessment interval required by 49 CFR Pat 192, Subpart O, regardless of HCA classification. Future ILI must be performed on a frequency consistent with Subpart O for the entire pipeline covered by this special permit.

41) Direct Assessment Plan: Headers, mainline valve bypasses and other sections in the *special permit area* 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).

42) Damage Prevention Program: The Common Ground Alliance's (CGA) damage prevention

best practices applicable to pipelines must be incorporated into the MEP damage prevention program.

43) Anomaly Evaluation and Repair: Anomaly evaluations and repairs in the *special permit area*, regardless of HCA status, must be performed based upon the following:

a) Anomaly Response Time: Repair Immediately

- Any anomaly within a *special permit area* operating up to 80% SMYS with a failure pressure ratio (FPR) equal to or less than 1.1 and/or an anomaly depth equal to or greater than 80% wall thickness.

b) Anomaly Response Time: Repair Within One Year

- Any anomaly within a *special permit area* operating at up to 80% SMYS with a FPR equal to or less than 1.25.

c) Anomaly Response Time: Monitored Conditions

- Anomalies not requiring immediate or one year repairs per paragraphs a and b above must be reassessed according to 49 CFR Part 192, Subpart O reassessment intervals.
- Each anomaly not repaired under the immediate repair requirements must have a corrosion growth rate and ILI tool tolerance assigned per the Gas Integrity Management Program (IMP) to determine the maximum re-inspection interval.

d) Anomaly Assessment Methods

- MEP must confirm the remaining strength (R-STRENG) effective area method, 0.85dL and ASME B31G assessment methods are valid for the pipe diameter, wall thickness, grade, operating pressure, operating stress level and operating temperature. MEP must also use the most conservative method until confirmation of the proper method is made to PHMSA Headquarters.
- Dents in the pipe in the *special permit area* must be evaluated and repaired per 49 CFR § 192.309(b) for the baseline geometry tool run and per 49 CFR § 192.933(d) for future ILI.

44) Potential Impact Radius Calculation Updates: If the pipeline operating pressures and gas quality are determined to be outside the parameters of the C-FER Study, a revised study with the updated parameters must be incorporated into the IMP.

45) Reporting - Immediate: MEP must notify the appropriate PHMSA regional office within

24 hours of any non-reportable leaks occurring in the *special permit area.*

46) Reporting – 30 Day: At least thirty (30) days prior to the pipeline in- service date under this special permit, MEP must report on its compliance with special permit conditions to PHMSA headquarters and the appropriate regional offices.

   a) Special Permit Conditions 1 through 25, 28, 29, 35, 36, 44 and 46 must be completed and implemented with documentation available for PHMSA review prior to operating at the Special Permit MAOP.
   b) Special Permit Conditions 3, 13, 14, 16, 18, 21, 22 through 34, 36 through 43, 45 and 47 must be included in the operator's written operating and maintenance (O&M) procedures manual concerning permit condition requirements with documentation available for PHMSA review prior to operating at the Special Permit MAOP.

47) Annual Reporting: MEP must report the following to the appropriate PHMSA regional offices annually[1]:

   a) The results of any ILI or direct assessment results performed within the *special permit area* during the previous year;
   b) Any new integrity threats identified within the *special permit area* during the previous year;
   c) The number of new residences, other structures intended for human occupancy and public gathering areas built within the *special permit area*;
   d) Any class or HCA changes in the *special permit area* during the previous year;
   e) Any reportable incidents associated with the *special permit area* that occurred during the previous year;
   f) Any leaks on the pipeline in the *special permit area* that occurred during the previous year;
   g) A list of all repairs on the pipeline in the *special permit area* made during the previous year;
   h) On-going damage prevention initiatives on the pipeline in the *special permit area* and a discussion of their success or failure;
   i) Any changes in procedures used to assess and/or monitor the pipeline operating under

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[1] Annual reports must be received by PHMSA by the last day of the month in which the Special Permit is dated. For example, the annual report for a Special Permit dated March 4, 2008, must be received by PHMSA no later than March 31st each year beginning in 2009.

this special permit; and

j) 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.

Limitations:

PHMSA grants this special permit subject to the following limitations:

1) PHMSA has the sole authority to make all determinations on whether MEP has complied with the specified conditions of this special permit.
2) Should MEP fail to comply with any of the specified conditions of this special permit, PHMSA may revoke this special permit and require MEP to comply with the regulatory requirements in 49 CFR §§ 192.111 and 192.201.
3) PHMSA may revoke, suspend or modify a special permit based on any finding listed in 49 CFR § 190.341(h)(1) and require MEP to comply with the regulatory requirements in 49 CFR §§ 192.111 and 192.201.
4) Should PHMSA revoke, suspend or modify a special permit based on any finding listed in 49 CFR § 190.341(h)(1), PHMSA will notify MEP in writing of the proposed action and provide MEP an opportunity to show cause why the action should not be taken unless PHMSA determines that taking such action is immediately necessary to avoid the risk of significant harm to persons, property or the environment (see 49 CFR § 190.341(h)(2)).
5) The terms and conditions of any corrective action order, compliance order or other order applicable to a pipeline facility covered by this special permit will take precedence over the terms of this special permit in accordance with 49 CFR § 190.341(h)(4).

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

Issued in Washington, DC on DEC 5 2008

JWiese

Jeffrey D. Wiese,
Associate Administrator for Pipeline Safety

U.S. Department
of Transportation

**Pipeline and Hazardous
Materials Safety
Administration**

1200 New Jersey Avenue, SE
Washington, D.C. 20590

DEC 5 2008

Mr. M. Dwayne Burton
Vice President, Gas Pipeline Operations and Engineering
Kinder Morgan, Inc.
One Allen Center
500 Dallas Street, Suite 1000
Houston, TX 77002

Docket No. PHMSA-2007-27842

Dear Mr. Burton:

On April 4, 2007, you wrote to the Pipeline and Hazardous Materials Safety Administration (PHMSA) requesting a waiver of compliance from the Federal pipeline safety regulations in 49 CFR §§ 192.111 and 192.201 for approximately 500-miles of proposed interstate natural gas transmission pipeline. This pipeline will be operated by Midcontinent Express Pipeline, LLC (MEP), a jointly owned subsidiary of Kinder Morgan Energy Partners, L.P., and Energy Transfer Partners L.P. The new pipeline will originate in Bryan County, Oklahoma, and run southeasterly through Texas, Louisiana and Mississippi to existing facilities in Choctaw County, Alabama.

On October 13, 2008, PHMSA published the final rule, Standards for Increasing the Maximum Allowable Operating Pressure for Gas Transmission Pipelines, which becomes effective 30 days after publication. The rule covers the requirements for any pipeline to operate at a design factor of up to 0.80 in Class 1 areas. PHMSA is proceeding with issuing the Midcontinent Express Pipeline special permit as a result of the thorough analysis contained in the Special Permit Analysis and Findings document, prepared well in advance of the final rule. Moreover, since the Midcontinent Express pipeline varies from certain provisions of the final rule, this special permit is necessary to cover all requested variances from regulations and required conditions, and is consistent with, or more stringent than, prior grants of special permit for existing pipelines.

PHMSA is granting this waiver through the enclosed special permit, which allows MEP to design, construct and operate the MEP pipeline in Class 1 locations, using a design factor in § 192.111 up to 0.80 and at stress levels up to 80% of the specified minimum yield strength (SMYS). This would result in a maximum allowable operating pressure (MAOP) of 1,480 psig. This special permit also allows MEP to design, install and operate pressure relief and limiting devices on the MEP pipeline, with a capacity that would ensure the pressure in Class 1 location pipeline segments would not exceed 104% of the MAOP, or the pressure that produces a hoop stress of 83.2% SMYS in the event an overpressure situation develops. This special permit has conditions and limitations and provides some relief from the Federal pipeline safety regulations for the MEP pipeline, while ensuring that pipeline safety is not compromised.

Docket No. PHMSA-2007-27842

My staff would be pleased to discuss this special permit or any other regulatory matter with you. John Gale, Director of Regulations, (202-366-0434), may be contacted on regulatory matters and Alan Mayberry, Director of Engineering and Emergency Support (202-366-5124), may be contacted on matters specific to this special permit.

Sincerely,

Jeffrey D. Wiese
Associate Administrator for Pipeline Safety

Enclosure: Special Permit