U.S. DEPARTMENT OF TRANSPORTATION

PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMINISTRATION (PHMSA)

SPECIAL PERMIT

Docket Number:	PHMSA-2007-27607
Pipeline Operator:	Southeast Supply Header, LLC (SESH)
Date Requested:	February 6, 2007
Code Section(s):	49 CFR §§ 192.111 and 192.201

Grant of Special Permit:

The Pipeline and Hazardous Materials Safety Administration (PHMSA) grants this special permit to the Southeast Supply Header, LLC (SESH), subject to the conditions and limitations set forth below, waiving compliance from 49 CFR §§ 192.111 and 192.201 for the SESH pipeline, a proposed 269-mile, 36-inch and 42-inch diameter, natural gas transmission pipeline to be installed from Delhi, Louisiana to Coden, Alabama. The SESH pipeline has approximately 104.5 miles of 42-inch pipe and 164.5 miles of 36-inch pipe in Class 1 locations.

This special permit allows SESH to design, construct and operate the SESH 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). The pipeline maximum allowable operating pressures (MAOP) will vary from 1200 pounds per square inch gauge (psig) to 1300 psig as follows:

SOUTHEAST SUPPLY HEADER DESIGN PRESSURES				
Class 1 location	**Diameter**	**Wall Thickness**	**MAOP**	**SMYS**
Line pipe	42-inch	0.427-inch	1300 psig	80%
Line pipe	42-inch	0.450-inch	1200 psig	80%
Line pipe	36-inch	0.402-inch	1250 psig	80%
Line pipe	36-inch	0.386-inch	1200 psig	80%

This special permit also allows SESH to design, install and operate pressure relief and limiting devices on the SESH 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-2007-27607 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. SESH 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, SESH 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 40% of pipe joints, with a minimum coverage of 35% of the pipe body for those joints inspected. Any laminations identified by the UT inspection program will be evaluated in accordance with the acceptance criteria defined in 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.

a) Pipe Transportation: All pipe transportation must be conducted in accordance with the applicable requirements of API 5L (e.g. API RP 5L1 for railroad transportation, API RP 5LW for waterway transportation). In the event of truck transportation, a fatigue analysis must be conducted to assure that no fatigue damage occurs during transportation.

b) An assessment must be conducted for all major material suppliers for the supply of pipe skelp, pipe manufacturing and coating application/materials. Significant deficiencies noted during these assessments must be corrected prior to commencing pipe skelp, pipe manufacturing or coating application/materials for the SESH Project.

c) In the event that a mid-wall lamination is identified during field construction welding or weld inspection, a metallurgical investigation must be required.

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 APL 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 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 SESH 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 SESH 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 and results must be 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: SESH must use the 20^{th} Edition, July 2007 Errata of API 1104, "*Welding of Pipelines and Related Facilities*" for welding procedures qualification, welder qualification and weld acceptance criteria for automatic or mechanized welding and the 19^{th} Edition of API 1104 for all other welding processes. SESH must inspect repair welds as required by API 1104 as follows:
    a) Manual UT inspection of 100% of the repair welds along with
    b) X-ray inspection of at least 75% of the repair welds.

    The appropriate PHMSA regional office must be notified within 14 days of the beginning of welding procedures qualification activities. Automated or manual welding procedures 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, SESH 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 (0.5 grain per 100 standard cubic feet or 8 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.

27) If H_2S is above 8 parts 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 6 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, SESH will determine if there have been any adverse affects to the pipeline and mitigate the affects as necessary. SESH 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 – SESH 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. SESH 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 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: SESH 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: SESH 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. SESH 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 SESH 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 60% wall thickness loss.

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 and/or an anomaly depth equal to or greater than 40% wall thickness loss.

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
- SESH 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. SESH 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. Pipe must be evaluated for out-of-roundness on the baseline geometry tool run and all indications in the pipeline above 6% out-of-roundness must be remediated.

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: SESH 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, SESH 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 - 34, 36 - 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: SESH 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 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 SESH has complied with the specified conditions of this special permit.
2) Should SESH fail to comply with any of the specified conditions of this special permit, PHMSA may revoke this special permit and require SESH to comply with the regulatory requirements in 49 CFR §§ 192.111 and 192.201.

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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.

3) PHMSA may revoke, suspend or modify a special permit based on any finding listed in 49 CFR § 190.341(h)(1) and require SESH 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 SESH in writing of the proposed action and provide SESH 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 JUL 1 7 2008.

Jeffrey D. Wiese,
Associate Administrator for Pipeline Safety.