CenterPoint Energy

Southeast Supply Header, LLC
1111 Louisiana, Suite 1120
Houston, Texas 77002

November 1, 2011

Wayne T. Lamoi, Director
Office of Pipeline Safety Southern Region
233 Peachtree Street Ste. 600
Atlanta, GA 30303

RE: CPF 2-2011-1007

Dear Mr. Lamoi,

This letter is written in response to the *Notice of Probable Violation, Proposed Civil Penalty and Proposed Compliance* CPF 2-2011-1007 (NOPV) date September 27, 2011, which was received by Southeast Supply Header, LLC (SESH) on October 4, 2011.

On July 17, 2008, PHMSA issued an order granting SESH a special permit with certain conditions and limitations (Order). Subsequent to the grant of the special permit, a representative of the PHMSA Southern Region, Office of Pipeline Safety, pursuant to Chapter 601 of 49 United States Code, initiated inspections and investigations to determine SESH's compliance with the Order. The NOPV was issued from the inspection of SESH's records and procedures in Shreveport, LA, from May 3-7, 2010, and inspection of SESH's pipeline facilities from Delhi, LA, to Coden, AL, from August 2-5, 2010.

SESH sent the civil penalty of $26,800 to the sender bank Friday morning, 10/28/2011 and instructed that the funds be wired 11/2/2011.

SESH is not contesting the findings of the inspection, but would like to submit additional information for the three items below.

The following is a list of items that your correspondence indicated that SESH had probable violations:

1. Condition 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

RECEIVED NOV 0 7 2011

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.

SESH failed to comply with Special Permit Condition 13 as set forth in the Special Permit Order of July 17, 2008, because SESH did not limit compressor station discharge temperatures to 120°F or less at five compressor stations. That is, the temperatures of the discharged natural gas at the Delhi, Gwinville, Collins, Petal, and Lucedale compressor stations exceeded 120°F on various occasions between the elate the pipeline began operating under the Special Permit (November 8, 2008) and
March 31, 2010.

Also, while SESH provided PHMSA with coating disbondment laboratory test data from the pipe manufacturers, SESH did not provide technical coating operating test data to show that the pipe coating will properly withstand the higher operating temperature for long term operations. Moreover, SESH did not provide to the regional offices where the pipe is in service a coating monitoring program or the results from such a program 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 in those areas where the compressor station discharge temperature exceeded l20° F.

The temperature data SESH provided the PHMSA inspector for the Delhi, Gwinville, Collins, Petal, and Lucedale compressor stations indicated temperatures exceeding
120°F at the following locations:

- Delhi Compressor Station: The data provided was identified *as Discharge Temp High for (ea) Delhi Unit 1 and Delhi Unit 2.*
- Gwinville Compressor Station: The data provided was identified as *Gwinville Unit 1 Discharge Temp High.*
- Collins Booster Station: The data provided was identified as Discharge Temp High for (ea) *Collins Unit 1 and Collins Unit 2.*
- Petal Booster Station: The data provided was identified as *Petal Unit 1 Discharge Temp High.*
- Lucedale Compressor Station: The data provided was identified as *Lucedale Unit 1 Discharge Temp High.*

Additional Information: *The SESH special permit requires compressor discharge temperatures be limited to a maximum of 120°F or that a coating monitoring plan be implemented in the areas that experience these temperatures to monitor for possible coating degradation. Temperatures were not expected to exceed 120°F, so the initial effort at monitoring the compressor discharge temperatures included the use of temperature probes located on station piping in close proximity to the compressor units. The probes are primarily designed to* *sound alarms or to shutdown the units in case of malfunction. Although most of the temperatures recorded using these probes met the temperature requirement, short duration spikes were recorded that exceeded the 120°F limit. Investigation of these spikes indicated a relationship to startup or shutdown of the units. As a solution, temperature probes were installed on the SESH mainline just downstream of all compressor inputs to determine if the 120°F limit was being exceeded as the gas enters the special permit section of the line. These probes became operational in August of 2010. A study of the temperature data was performed between August 1, 2010 and October 31, 2010 by comparing the temperatures recorded on the station piping to those of the newly installed probes on the mainline. The data comparisons at each compressor location on the SESH mainline showed that temperature spikes were still occasionally recorded at the station piping probes, while at the same time, no temperatures above 120°F were recorded at the mainline locations on the special permit pipe. Although not definite proof, this evidence appears to indicate that all previous temperature spikes were not likely experienced on the special permit pipe on the SESH mainline and that SESH met the requirements of Condition 13.*

2. Condition 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 arc not practical. The marking of pipelines is also subject to Federal Energy Regulatory Commission orders or environmental permits and local restrictions.

SESH failed to comply with Special Permit Condition 36 as set forth in the Special Permit Order of July 17,2008, because SESH did not employ line-of-sight markings on the pipeline in the special permit area. The PHMSA inspector could not see pipeline markers on August 5, 20 1 0, looking downstream along Line I 00 from the
Hi-Fields tap location at station 13408+54 to the fence-line at station 13417+14. Vegetation obstructed the view of the line marker at the fence-line. While there was an agricultural field between these markers, the agricultural exception in Condition 36 did not apply because the fence-line and adjacent road were at the edge of the
field - not in the agricultural field itself

Additional information: *FERC imposes conditions related to maintenance and repair activities in its orders issuing certificate authorizations. Such conditions may relate to construction techniques, restoration requirements or on-going maintenance of pipeline right-of-way. For example, the FERC routinely includes the following condition in orders authorizing pipeline construction: Routine vegetation maintenance clearing shall not be done more frequently than every 3 years. However, to facilitate periodic corrosion and leak surveys, a corridor not* *exceeding 10 feet in width centered on the pipeline may be maintained annually in an herbaceous state. Routine vegetation maintenance clearing shall not occur between April 15 and August 1 of any year. This condition is also one of the myriad of provisions in FERC's "Upland Erosion Control, Revegetation and Maintenance Plan". By including the provision in its order, FERC is placing this requirement on the pipelines for the life of the pipeline.*

The day of the inspection was August 5. SESH's Annual Right-of-Way maintenance had begun on August 1st and was in progress and moving toward the area that was inspected. Crews performing this maintenance cut the allowed 10-foot-wide corridor the day after discovery (August 6) and replaced the marker in question with an extended height bullet type marker while the inspection was still taking place.

SESH inspects for and adds or replaces line-of-sight markers during normal O&M activities and performs annual surveys, as described in the O&M procedures and approved by PHMSA, to identify and replace missing markers. In addition, markers are inspected during monthly aerial patrols. Downed or missing markers are addressed and repaired as a result of these aerial patrols

3. Condition 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:
... d) Anomaly Assessment Methods
... 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.

SESH failed to comply with Special Permit Condition 43 as set forth in the Special Permit Order of July 17, 2008, because SESH did not adequately evaluate and repair a dent in the Line I 00 pipe per §192.309(b) that was discovered with a baseline geometry tool run.

SESH ran a baseline geometry in-line inspection (ILI) tool on Line I 00 and received a final report from the ILI vendor dated August 21, 2008. The ILI final report showed a 5.3% dent (Feature No. 218) that SESH did not evaluate and repair. Condition 43 required SESH to evaluate and repair a dent that exceeded "*more than 2% of the nominal pipe diameter*" per §192.309(b)(3)(ii).

In April 2010 (20 months later), SESH discovered and removed a "buckle" at this same location during an unrelated excavation. This unplanned discovery and removal of the buckle (and thus the 5.3% dent) did not meet the intent of Condition 43 because it allowed the dent to remain in this Special Permit pipeline from about August 2008 until August w2010. This pipeline was approved to operate above 72% of the specific minimum yield strength (SMYS) in Class 1 locations and began operating under this approval on November 8, 2008.

SESH also did not adequately evaluate the data from the baseline geometry ILI tool run on Line I00 for indications of out-of-roundness. In May 2010 (21 months after the final ILI report), SESH received another report from its contract auditor that stated that Features No. 127 and l34 (as shown in the ILI vendor's August 3, 2008, final report) exceeded 6% out-of-roundness: 6.17% and 6.98%, respectively. While SESH subsequently excavated and assessed the pipe at these locations and determined that no further action was required, this did not meet the intent of Condition 43 because it allowed the out-of-roundness features to remain in this Special Permit pipeline that was approved to operate above 72% of SMYS in Class I locations from about November 2008 until October 2010.

Additional Information: *As previously communicated to PHMSA via e-mail on April 27, 2010, SESH utilized the preliminary caliper tool vendor report to make excavation/investigation decisions relating to pipe deformation indications due to project timing. It is common for an ILI tool vendor to issue a preliminary ILI report which is intended to allow the client to begin assessment of "actionable" features while the final report is prepared. SESH began its baseline assessment of features exceeding the acceptance criteria detailed in CFR 192.309(b) and the special permit with the preliminary report issued on 7/23/2008 by the ILI vendor. The final ILI report (issued 8/21/2008) contained additional "actionable" features which were not included in the preliminary report. ILI vendor did not provide SESH specific notification of such additions and SESH did not detect the additional actionable features. As a result, the deformation features noted in the NOPV were not excavated and investigated prior to the SESH pipeline being placed into service.*

SESH has implemented a number of changes to assure all deformation features are properly identified, classified and investigated prior to placing a new pipeline in service. These steps include:

- *SESH has reviewed its list of approved ILI vendors and only includes those that are capable of performing at industry leading levels of anomaly detection and reporting.*
- *SESH has amended its specification for geometry inspection for new construction to require geometry tool vendors to provide prompt notification of any features annexed to the final report which were not reported in the preliminary, as described below.*

SESH Specification IP-MP2.1, Pipeline Geometry Inspection with Caliper Pigs – New Construction, Section 12A2: *"If, at any time, there are any features annexed to the final report that were not initially identified in the preliminary report, the ILI vendor must provide prompt notification of such additions. Reconciled data, including new wheel counts for new or altered features shall be included with the notification."*

PROPOSED COMPLIANCE ORDER

Pursuant to 49 United States Code§ 60118, the Pipeline and Hazardous Materials Safety Administration (PHMSA) proposes to issue to the Southeast Supply Header, L.L.C. (SESH) a Compliance Order incorporating the following remedial requirements to ensure SESH complies with the Special Permit Order issued on July 17, 2008.

1. In regard to Item Number 1 of the Notice pertaining to the failure of SESH to limit the compressor station discharge temperatures to 120°F at the Delhi, Gwinville, Collins, Petal, and Lucedale compressor stations, SESH must

a. modify its compressor station operations, procedures, and/or facilities to ensure that the discharge temperature at each of the five compressor stations on Line I 00 does not exceed 120°F as required by Special Permit Condition# 13

OR

b. notify the Director, Office of Pipeline Safety, PHMSA Southern Region in writing of its intent to operate Line I 00 at discharge temperatures above 120°F. To do so, SESH must provide PHMSA with technical coating operating tests to show that the pipe coating can properly withstand the higher operating temperatures for long term operations and SESH must institute and provide to PHMSA a coating monitoring program as described in Special Permit Condition# 13.

SESH must complete either Item (a) or (b) above within 60 clays of receipt of the Final Order or PHMSA may issue a show cause letter modifying, revoking, or suspending the Order issued under PHMSA-2007-27607.

2. In regard to Item Number I of the Notice pertaining to the failure of SESH to limit the compressor station discharge temperatures to l20°F at five compressor stations, and notwithstanding Compliance Order Item 1 above, SESH must develop and implement a coating assessment program downstream of the five compressor stations on Line 100 to ensure the coating has not been damaged or compromised. This assessment must be completed using

   - Direct Current Voltage Gradient (DCVG) surveys,
   - Alternating Current Voltage Gradient (ACVG) surveys; or,
   - other testing to demonstrate the integrity of the coating.

In the coating assessment program, SESH must address

a. The coating on the pipe at least 5 miles downstream of each of the five compressor stations or to a point on each pipeline where the actual or predicted temperature consistently dropped below 120°F, whichever is further downstream.
b. A technical analyses to determine or predict the highest temperature that Line 100

experienced, or was projected to experience, immediately downstream of each of the five compressor stations, and to determine a point on each pipeline where the actual or predicted temperature consistently dropped below 120°F.

c. Technical coating operating tests to show the pipe coating could properly withstand the operating temperatures determined or predicted.
d. If using DCVG and/or ACVG, define threshold survey indication values (% IR for DCVG and dBµV for ACVG). The values should represent the mid-range of the "Moderate" category in the severity classification used to characterize survey indications.
e. Excavation and remediation of all indications found above the threshold values.
f. A calibration dig on at least one anomaly classified as "Minor" to ensure findings that are not all indications found above the threshold,values in the remediation plan are not detrimental to the pipeline.
g. Perform holiday voltage tests (jeep) and coating adhesion tests at all excavations.
h. Disbonded, blistered or coating with cracking and/or other damage that could compromise cathodic protection found during excavations must be removed and new coating applied.
1. The coating assessment must be completed no later than 6 months after the date of this Compliance Order.
J. Submit the results of the coating assessment to the Director, Office of Pipeline Safety, PHMSA Southern Region for review and approval no later than 90 days after the coating assessment is complete but not later than 9 months after the date of this Compliance Order.

SESH must complete Item 2 above within 90 days of receipt of the Final Order or PHMSA may issue a show cause letter modifying, revoking, or suspending the Order issued under PHMSA-2007-27607.

Based upon the additional information provided in Item 2 above, SESH requests the PHMSA review the need for this Proposed Compliance Order. However, if the Proposed Compliance Order stays in effect, SESH is seeking further clarification related to the timeline for Item 2. Item 2.l. states that the coating assessment must be completed no later than 6 months after the date of the Compliance Order. Item 2.j. states that the results of the coating assessment be provided for review no later than 90 days after the coating assessment is complete but not later than 9 months after the date of this Compliance Order. Following, the Compliance Order states that "SESH must complete Item 2 within 90 days of receipt of the Final Order . . ." which appears to be in conflict with the requirements of Item 2 stated above. Please clarify the timeline by which Item 2 must be completed.

SESH believes in a safety culture and is committed to the continuous improvement and effectiveness of our pipeline safety programs as exhibited by the steps taken to address the issues identified in this response.

9

If you have any questions concerning the actions we have taken, please feel free to give me a call.

Sincerely,

Walter Ferguson

Walter Ferguson
Division Sr. VP MidStream Field Operations, Engineering & Construction

CC:	Pete Kirsch	Royce Brown
	Chris Bullock	Johnny Cavitt