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David Lykken- Director of Pipeline Safety Program
State of Washington Utilities and Transportation Commission
1300 S. Evergreen Park Dr. SW
P.O. Box 47250
Olympia, WA 98504-7250

Subject: Response to 2103 Natural Gas Standard Inspection – Bellingham District

Dear Mr. Lykken,

This letter is intended to address all probable state safety code violations and areas of concern. We specifically are addressing how and when we plan to bring the probable violations and areas of concern into full compliance. The inspection was conducted on May 13-16, 2013 in Bellingham, Washington.

The following is in response to one probable violation and two areas of concern:

PROBABLE VIOLATIONS

1. 49 CFR §192.619 Maximum allowable operating pressure (MAOP)- Steel or plastic pipelines

(a) No person may operate a segment of steel or plastic pipeline at a pressure that exceeds a maximum allowable operating pressure determined under paragraph (c) or (d) of this section, or the lowest of the following:

(1) The design pressure of the weakest element in the segment, determined in accordance with subparts C and D of this part.

(2) The pressure obtained by dividing the pressure to which the segment was tested after construction as follows:

(i) For plastic pipe in all locations, the test pressure is divided by a factor of 1.5.

(ii) For steel pipe operated at 100 p.s. i. (689 kPa) gage or more, the test pressure is divided by a factor determined in accordance with the following table:

Factors (see Note)

Class location	*Segment Installed Before Nov. 12, 1970*	*Segment Installed After Nov. 11, 1970*	*Segment Converted under§192.14*
1	*1.1*	*1.1*	*1.25*
2	*1.25*	*1.25*	*1.25*
3	*1.4*	*1.5*	*1.5*
4	*1.4*	*1.5*	*1.5*

Note: For offshore segments installed, or updated, or converted after July 31, 1977, that are not located on an offshore platform, the factor is 1.25. For segments installed, uprated, or converted after July 31, 1977 that are located on an offshore platform or on a platform in inland navigable waters including a pipe riser, the factor is 1.5.

(3) The highest actual operating pressure to which the segment was subjected during the 5 years preceding the applicable date in the second column. This pressure restriction applies unless the segment was tested according to the requirements in paragraph (a)(2) of this section after the applicable date in the third column or the segment was uprated according to the requirements in subpart K of this part:

Pipeline segment	*Pressure date*	*Test date*
-Onshore gathering line that first became subject to this part (other than §192.612) after April 13, 2006. *-Onshore transmission line that was a gathering line not subject to this part before March 15, 2006.*	*March 15, 2006, or date line becomes subject to this part, whichever is later.*	*5 years preceding applicable date in second column.*
Offshore gathering lines	July 1, 1976	July 1, 1971
All other pipelines	July 1, 1970	July 1, 1965

(4) The pressure determined by the operator to be the maximum safe pressure after considering the history of the segment, particularly known corrosion and the actual operating pressure.

(b) No person may operate a segment to which paragraph (a)(4) of this section is *applicable, unless overpressure protective devices are installed on the segment in a manner that will prevent the maximum allowable operating pressure fi'om being exceeded, in accordance with § 19 2.19 5.*

(c) The requirements on pressure restrictions in this section do not apply in the following instance. An operator may operate a segment of pipeline found to be in satisfactory condition, considering its operating and maintenance his/my, at the highest actual operating pressure to which the segment was subjected during the 5 years preceding the applicable date in the second column of the table in paragraph (a)(3) of this section. An operator must still comply with §192.611.

(d) The operator of a pipeline segment of steel pipeline meeting the conditions prescribed in§ 192.620(b) may elect to operate the segment at a maximum allowable operating pressure determined under§ 192.620(a).

Finding(s):

During the records review to confirm MAOP of HP lines, CNG staff were asked to produce the MAOP confirming documents for Line 1-8" Bellingham HP. CNG at the time of the inspection could not produce supporting MAOP documents for this line. This line was installed in 1957. The two documents CNG did produce cannot be considered reliable records. One was undated and titled "Construction Specification for Proposed Pipeline (Order Cause Nos.U-8799-8800, Rule 20)". This document notes the pipeline was to be tested to a pressure of 500 psi. The other document was a 1970 letter to Lee Johnson & Associates which states that the line was "built to the following specifications" including pipe grade, diameter, thickness, coating and construction test pressure. These documents do not provide a definitive answer supporting the current MAOP of 380 psi as they are not original record documents. CNG is searching their files for any additional information on this pipeline, however, the records available during the inspection do not allow confirmation of MAOP according to this subpart.

Records (and their management), especially of MAOP confirming documents, must be complete, accurate and readily available. CNG needs to have documents which support all the "facts" outlined in the 1970 letter to Lee Johnson & Associates for Line 1-8" Bellingham HP. If pipe material cannot be ascertained, then 49 CFR 192.105 requires using 24,000 as the pipe strength in the design pressure formula to calculate MAOP.

Additionally, records management (not being able to find MAOP confirming documents) was also an issue during the 2013 CNG Longview inspection. It appears that this is not an isolated incident. Therefore, CNG must confirm the MAOP of all their HP lines with supporting documentation for Bellingham as well as all other districts. Please tell us the date by which CNG can produce the confirmation with supporting documentation.

Cascade Response

Cascade Natural Gas Corporation (CNGC) acknowledges that MAOP confirming documents for Line 1 8" Bellingham HP were not available during the audit. A review of all CNGC HP records has been initiated and is anticipated to be completed by September 30, 2013. As part of this review, CNGC will address any HP lines whose MAOP confirming documents cannot be located.

AREAS OF CONCERN OR FIELD OBSERVATIONS

2. WAC 480-93-124 Pipeline Markers

(1) Each gas pipeline company must place pipeline markers at the following locations:

(a) Where practical, over pipelines operating above two hundred fifty psig;

(b) Over mains and transmission lines crossing navigable waterways (custom signage may be required to ensure visibility);

(c) Over mains and transmission lines at river, creek, drainage ditch, or irrigation canal crossings where hydraulic scouring, dredging, or other activity could pose a risk to the pipeline (custom signage may be required to ensure visibility);

(d) Over gas pipelines at railroad crossings;

(e) At above ground gas pipelines except service risers, meter set assemblies, and gas pipeline company owned piping downstream of the meter set assembly. The minimum lettering size requirements located in 49 CFR § 192.707 (d)(I) do not apply to services;

(f) Over mains located in Class I and 2 locations;

(g) Over transmission lines in Class 1 and 2 locations, and where practical, over transmission lines in Class 3 and 4locations; and

(h) Over mains and transmission lines at interstate, US and state route crossings where practical.

(2) If practical, the gas pipeline company must place markers on both sides of any crossing listed in subsection (I) of this section.

Finding(s):

During pre-inspection field reconnaissance it was noted that at several locations-Sumas Ave. at Johnson Creek, Double Ditch Rd at Main St. in Lynden and E. Badger Rd at Fishtrap Creek in Lynden- CNG markers were not present. When asked about these locations, CNG sent personnel out to evaluate. It was determined that markers were needed. CNG generated work-orders and had these installed before end of inspection. However, it brings up the question as to how many more water: crossings might need markers. CNG needs to evaluate all water crossings per (1) (c) above and determine if markers are needed. If markers are needed, they shall be installed and added to CNG's GIS system. Please tell us the date by which CNG will have this evaluation completed.

Cascade Response

CNGC has initiated the supplementary pipeline marker evaluation in the Bellingham district. The evaluation is anticipated to be completed by December 31, 2013. A correction should be noted for one of the field locations cited in the finding. Markers were not placed on East Badger Road at Fishtrap Creek as CNGC does not have a main or a transmission line that crosses the creek at this location but other crossings near this area were inspected for markers and remediation was made where needed.

3. 192.467 External corrosion control: Electrical isolation

(d) Inspection and electrical tests must be made to assure that electrical isolation is adequate.

Finding(s):

During the field inspection of the Sumas Gate station, CNG personnel noted that they cannot check isolation between the CNG and Spectra piping as this would require a border crossing to physically test. CNG stated that their corrosion personnel are aware of this and are working on a solution. CNG must be able to inspect and test the isolation between the two systems. Please tell us the date by which CNG will have a solution for this area of concern

Cascade Response

During the field inspection, CNGC's staff performed the OQ task as assigned, however answering the question regarding electrical isolation was beyond the scope of his expertise. CNGC's Corrosion Department has responsibility for monitoring all work performed in the field as it relates to corrosion control. To address the isolation question posed by WUTC staff, the Manager of Corrosion Control was consulted to explain the process for checking electrical isolation at the Sumas Gate Station and to verify it is being monitored. He indicated this takes place during the annual CP surveys. The process is to take a pipe to soil potential within the Sumas Gate Station to verify normal CP operations. Should the potential indicate a change in normal CP operations, a Corrosion Control Tech. would initiate troubleshooting to determine the cause of the deficiency. CNGC will continue to monitor electrical isolations during the annual survey.

Please contact Steve Kessie at 509-734-4575 with questions or comments.

Respectfully Submitted,

Eric Martuscelli,
Vice President, Operations
Cascade Natural Gas Corporation