El Paso Natural Gas Company, L.L.C.
a Kinder Morgan company

August 25, 2016

R.M. Seeley,
Director, Southwest Region
Pipeline and Hazardous Materials Safety Administration
Office of Pipeline Safety
8701 S. Gessner Rd, Suite 1110
Houston, TX 77074

Re: Response to CPF 4-2016-1005 - Notice of Probable Violation (NOPV), Proposed Civil Penalty, and Proposed Compliance Order (CO) for El Paso Natural Gas Company, L.L.C. West-North pipeline system

Dear Mr. Seeley,

El Paso Natural Gas Company, L.L.C. (EPNG) has reviewed and analyzed the NOPV referenced above, in which PHMSA alleges that EPNG has committed probable violations of the Pipeline Safety Regulations, Title 49, Code of Federal Regulations and provides the following response.

While EPNG does not agree with each of the allegations, EPNG will not be contesting the findings and we have submitted payment on August 24, 2016 for the civil penalty assessed by the fore mentioned NOPV.

EPNG has also reviewed the associated Proposed Compliance Order (CO). EPNG is not contesting the Proposed CO but is providing additional information and clarifications which we request PHMSA consider when issuing the final order.

For the purposes of clarity, the CO items presented by your office will be restated with EPNG's response immediately following in bold font.

CO Item 1: In regard to Item Number 3 of the Notice pertaining to EPNG failing to provide a level of cathodic protection (CP) that complies with the applicable criteria contained in Appendix D of Part 192, EPNG must review and modify appropriate procedures as necessary to ensure compliance with the regulations. EPNG shall perform and document the appropriate tests to show that the protection that is being applied meet one of the applicable criteria.

EPNG CO Item 1 EPNG Response:

EPNG will perform and document the appropriate tests to show that protection that is being applied meets one of the applicable criteria contained in Appendix D of Part 192 within 180 days of the receipt of the final order.

CO Item 2: In regard to Item Number 10 of the Notice pertaining to EPNG's failure to diligently verify capacities of relief devices installed on the company pipeline system, EPNG must perform a Survey of the overpressure protection devices currently installed on EPNG's natural gas pipeline system. The survey is to evaluate the overpressure protection devices to collect and/or verify data such as inlet and outlet size, the orifice area and coefficient of actual discharge in order to perform sizing calculations. If deficiencies are observed during the calculation of sizing capacities, EPNG must integrate the findings and verify that the regulator and relief devices installed on the facilities have adequate capacities required by 49 CFR §192.743. If the capacity is found to be insufficient, EPNG must install/modify the equipment to provide the required capacity.

EPNG CO Item 2 Response:

Upon receipt of the NOPV, EPNG initiated a plan to survey the overpressure protection devices currently installed on EPNG's natural gas pipeline system. As required by the CO, EPNG will survey these devices to collect and/or verify data such as inlet and outlet size, orifice area and coefficient of actual discharge in order to perform sizing calculations. EPNG qualified personnel will perform and document the calculations as prescribed within *O&M Procedure 703 – Pressure Limiting and Relief Devices and Inspections*.

Observed deficiencies will be integrated into the findings and corrected. If the capacity is found insufficient EPNG will install/modify the equipment to provide the required capacity.

As demonstrated by the post-inspection evaluation of the OPP devices (as noted in NOPV Item 10) and based on EPNG's initial review, the OPP device capacities have been found to be adequate. Based on these initial findings, the scope of survey, with several hundred compressor station, meter station and pipeline OPP devices to evaluate, and in order to ensure consistency with the established inspection intervals, which require capacity calculations once per calendar year not to exceed 15 months, EPNG is requesting an extension to the 180 days specified in the CO to complete the evaluation one (1) year from the receipt of the final order and provide documentation verifying completion 13 months from the receipt of the final order.

CO Item 3. In regard to Item Number 11 of the Notice pertaining to EPNG failing to develop and include a covered task or tasks in the Operator Qualification Plan for loading, launching, receiving and unloading ILI smart tools for both in-service and out-of service pipelines, EPNG must develop a covered task for the ILI process. The covered task must cover the tasks for loading, launching, receiving and unloading ILI smart tools for both in-service and out-of-service pipelines and incorporate them into the OQ Program.

EPNG CO Item 3 Response:

Based on conversations with the PHMSA Southwest Region inspectors during and following the EPNG West-North pipeline inspection, conducted between November 19, 2014 and August 22, 2014, EPNG implemented *Kinder Morgan OQ Task 14.11.05 – Launching and Receiving Internal Devices*. The task was created on July 7, 2015 and effective October 15, 2015. As required by 49 CFR 192.805, PHMSA's Information Resources Manager received notification of the change on October 2, 2015. The task summary has been attached for PHMSA's review. This item is complete.

CO Item 4. Provide PHMSA with documentation that verifies completion of numbers 1 & 2 above within 180 days following the receipt of the Final Order. For number 3, provide PHMSA with documentation verifying completion within 90 days following receipt of the Final Order.

EPNG CO Item 4 Response:

As noted above, EPNG will provide PHMSA with documentation that verifies completion of the CO Items 1, 2, and 3 as required by CO Item 4 but is requesting an extension to CO Item 2. Therefore, EPNG also requests that PHMSA modify CO Item 4 in the final order to give EPNG 13 months from the receipt of the final order to provide PHMSA with documentation verifying completion of CO Item 2.

Although EPNG is not contesting the NOPV as written, we are providing the following additional supporting information for your consideration related to the NOPV. As before, for the purposes of clarity, the issues presented by your office will be restated with EPNG's response immediately following in bold font.

Item 1: §191.5 Immediate notice of certain incidents.

(a) At the earliest practicable moment following discovery, each operator shall give notice in accordance with paragraph (b) of this section of each incident as defined in §191.3.

EPNG failed to give notice at the earliest practical moment following discovery of each incident as defined in §191.3.

PHMSA reviewed the incident reports for the years 2010-2013 for Inspection System #1720. There were 8 eight reports for this time period. Incident #20110308-16140 in PHMSA Unit 15144 exceeded the notification period of 2 hours. The NRC notification was made 4 hours and 45 minutes following the incident.

EPNG Response 1:

Based on a review of the actions taken, EPNG has determined that under the 2011 incident reporting regulations 49 CFR 191.5 and applicable PHMSA Advisory Bulletins, notice was made at the earliest practical moment following discovery of the incident as defined in §191.3.

The initial event, a leak, was reported to EPNG Gas Control by a contract security guard, not trained to determine whether an event on the pipeline met the definition of an incident under 49 CFR 191.3. EPNG personnel traveled to the site and were then able to determine that this event was an incident as defined in 49 CFR 191.3.

The analysis of whether EPNG reported incidents in a timely manner by only comparing the local time and date of the incident against the time of the initial report to the National Response Center (NRC), as documented on the PHMSA Incident Report Form 7100.2, fails to take into account the time it takes to review an event and make the determination of reportability before making the initial report to the NRC.

Item 2: §192.459 External corrosion control: Examination of buried pipeline when exposed.

Whenever an operator has knowledge that any portion of a buried pipeline is exposed, the exposed portion must be examined for evidence of external corrosion if the pipe is bare, or if the coating is deteriorated. If external corrosion requiring remedial action under Secs. 192.483 through 192.489 is found, the operator shall investigate circumferentially and longitudinally beyond the exposed portion (by visual examination, indirect method, or both) to determine whether additional corrosion requiring remedial action exists in the vicinity of the exposed portion. EPNG failed to perform a visual examination on the segment of exposed buried pipeline (Line 1104) searching for evidence of deteriorated coating and/or external corrosion.

Kinder Morgan *O&M Procedure 918 Inspecting for Atmospheric Corrosion*, section 3.2. *Atmospheric Corrosion Monitoring and Inspection Frequency states, "Buried or submerged pipe that has become exposed to the atmosphere (e.g. by erosion, changing water levels) must be initially inspected and documented on O&M Form OM200-02 – Pipeline Examination Report, then inspected for evidence of atmospheric corrosion according to the frequencies required by this section while the pipe is exposed..."*

Work Order #12-4965319 provided by EPNG was for a patrol conducted on 1/18/2013.

Line 1104 had been exposed by runoff waters following a rainstorm. The patrol record had a photo attached showing the exposure. There was a follow-up WO #13-319519 created, but no form OM200-02 was found documenting the inspection (i.e. visual examination) was performed prior to the reburial of the pipeline.

A visual examination of the coating on the exposed portion of Line 1104 was not performed.

EPNG Response 2:

For clarity purposes, note that up until March 1, 2014 EPNG personnel were operating under the interim Kinder Morgan O&M Procedure 970 – *Corrosion Control Procedures, EPPG Section 308.2 External Corrosion Control*, which did not require the use of O&M 200-02. After March 1, 2013 all EPNG personnel were operating under the Kinder Morgan *O&M Procedure 918 – Inspecting for Atmospheric Corrosion* and therefore were required to use *O&M Form OM200-02 – Pipeline Examination Report.*

EPNG will continue to document the visual examination of pipeline that has become exposed to the atmosphere in conformance with *O&M Procedure 918 – Inspecting for Atmospheric Corrosion* and 49 CFR 192.459, as it has done since March 1, 2013.

Item 3: §192.463 External corrosion control: Cathodic protection.

(a) Each cathodic protection system required by this subpart must provide a level of cathodic protection that complies with one or more of the applicable criteria contained in Appendix D of this part. If none of these criteria is applicable, the cathodic protection system must provide a level of cathodic protection at least equal to that provided by compliance with one or more of these criteria.

EPNG did not provide a level of cathodic protection (CP) on Line 1300 that complies with the applicable criteria contained in Appendix D of Part 192.

PHMSA reviewed the CP Survey records for Line 1300 Plains to San Juan, MP 53 0+00 through MP 236 0+00. EPNG identified the section of pipeline between MP 53 0+00 to MP 122 0+00 as being protected by applying the 100 mV polarization decay criteria. The annual surveys were reviewed and indicate the protection was below the level of CP that complies with the applicable criteria. Over the period 2012 through 2014, thirty-seven (37) test points had P/S reads that did not meet the 100 mV polarization shift.

EPNG Response 3:

Refer to *EPNG CO Item 1 Response* above.

Item 4: §192.465 External corrosion control: Monitoring.

(a) Each pipeline that is under cathodic protection must be tested at least once each calendar year, but with intervals not exceeding 15 months, to determine whether the cathodic protection meets the requirements of §192.463. However, if tests at those intervals are impractical for separately protected short sections of mains or transmission line, not in excess of 100 feet (30 meters), or separately protected service line, these pipelines may be surveyed on a sampling basis. At least 10 percent of these protected structures, distributed over the entire system must be surveyed each calendar year, with a different 10 percent checked each subsequent year, so that the entire system is tested in each 10-year period. EPNG failed to test each pipeline that is under cathodic protection at least once each calendar year, but with intervals not exceeding 15 months, to determine whether the cathodic protection met the requirements of §192.463.

Kinder Morgan Procedure O&M 903 *External Corrosion Control for Buried or Submerged Pipelines*, section 3.4 *CP Surveys, Monitoring and Adjustments*, sub-section 3.4.1 *Pipe-to-Soil Surveys* states,

"Measure pipe-to-soil readings at least once each calendar year, not to exceed 15 months at all established test points on all pipelines and appurtenances needed to meet the applicable criteria. Increase inspection frequency when conditions warrant."

PHMSA reviewed EPNG Annual Cathodic Protection Survey records for inspection system #1720 for the years 2011 through 2014. The review identified the failure of EPNG to perform the annual surveys on Lines 1104, 1112, 1113, 1208, 2134, the Dutch Flat Compressor Station underground piping located in unit 55334 (Topock Area ACC) and Line 1300 – Roswell at MP 59 0+00 within the required 15-month interval. The Line 1300 survey also skipped the calendar year 2012. The survey dates were as follows:

Line 1104 5/14-21/2012 through 9/1-4/2013,
Line 1112 5/21-24/2012 through 9/5/2013,
Line 1113 5/21-24/2012 through 9/5/2013,
Line 1208 5/21-23/2012 through 9/5/2013,
Line 2134 5/17/2012 through 9/4/2013, and
Line 1300 8/28/2011 through 7/28/2013

In each instance, the 15-month interval was exceeded.

EPNG Response 4:

We have reviewed our procedures and processes to ensure we complete our inspections on time and that the processes address the requirements of O&M Procedure 903 - *External Corrosion Control for Buried or Submerged Pipelines* and 49 CFR 192.465. For clarity, the survey for the entire Line 1300 was not skipped in the calendar year 2012.

Item 5. §192.475 Internal corrosion control: General.

(b) Whenever any pipe is removed from a pipeline for any reason, the internal surface must be inspected for evidence of corrosion. If internal corrosion is found-

(1) The adjacent pipe must be investigated to determine the extent of internal corrosion:

(2) Replacement must be made to the extent required by the applicable paragraphs of §§192.485, 192.487, or 192,489; and,

(3) Steps must be taken to minimize the internal corrosion.

EPNG failed to inspect the internal surface of a section of a cut out pipe for evidence of internal corrosion as required by §192.475(b). The Operator was unable to locate and provide records to verify that the internal pipe surface inspection was performed. Kinder Morgan Procedure O&M 906 *Internal Corrosion Control*, section 3.6 *Internal Corrosion Inspection - Pipeline Repairs* states, *"Whenever any pipe is removed from a pipeline for any reason, inspect the internal surface for evidence of corrosion"*.

When reviewing Project AFE 63171 involving the excavation, inspection and recondition of 420 feet of Line 3201, the PHMSA inspector learned EPNG observed extensive lamination during the UT wall thickness survey. As a result, EPNG decided to cut out and replaced 41 feet of pipe. A review of the Pipeline Examination Report – IMP (Form OM200-02) revealed EPNG marked "N/A – Inside Surface of Pipe Not Exposed". PHMSA raised this question and EPNG personnel stated the replacement of pipe project was under AFE 91222. Upon review of Project AFE91222, PHMSA found the Pipeline Examination Report marked "N/A – Inside Surface of Pipe Not Exposed". EPNG stated they would investigate further to locate records. On 7/7/2014, EPNG provided a corrected Pipeline Examination Report along with the qualification records for the employee who was said to have performed internal inspection. When the PHMSA inspector questioned the revised form OM200-02IMP, EPNG personnel stated the form was corrected after the PHMSA inspector brought it their attention. EPNG also provided a signed affidavit of an employee dated 7/18/2014 indicating he performed an internal inspection, after the PHMSA inspection.

EPNG Response 5:

As noted within the NOPV Item 5, the work was completed as required but was not documented completely at the time the work was performed. EPNG personnel will document all inspections of the pipeline's internal surface for evidence of corrosion in conformance with *O&M Procedure 906 –Internal Corrosion Control* and 49 CFR 192.475.

Item 6: §192.605 Procedural manual for operations, maintenance, and emergencies

(a) General. Each operator shall prepare and follow for each pipeline, a manual of written procedures for conducting operations and maintenance activities and for emergency response. For transmission lines, the manual must also include procedures for handling abnormal operations. This manual must be reviewed and updated by the operator at intervals not exceeding 15 months, but at least one each calendar year. This manual must be prepared before operations of a pipeline system commence. Appropriate parts of the manual must be kept at locations where operations and maintenance activities are conducted.

§192.736 Compressor stations: Gas detection.
(c) Each gas detection and alarm system required by this section must be maintained to function properly. The maintenance must include performance tests. EPNG failed to follow procedures and maintain the gas detection and alarm equipment at San Juan compressor station to function properly as required by §192.736(c) and Kinder Morgan Engineering Design Manual E0200 *Compression*.

Kinder Morgan Engineering Design Manual Procedure E0200 *Compression*, section 17.1

Gas Detectors states, *"Gas detectors with high and low alarm set points shall be installed in all compressor buildings and in all turbine engine enclosures. The low set point shall be in conformance with Company O&M Procedure 550 - Testing Gas and Fire Detection Systems. This alarm shall provide a visual and audible warning inside the compressor building. To warn personnel approaching the compressor building, visual alarm(s) shall be installed outside the building or enclosure consisting of a minimum of two strobe lights, one each on opposite corners of the building, located so that at least one light is clearly visible from all building entrances..."*

Kinder Morgan Procedure O&M 550 *Testing Gas and Fire Detection Systems*, section 2 *Scope* states,

"This procedure outlines minimum requirements for calibrating and testing gas and fire detection equipment installed at Company owned and/or Company-operated facilities."

On June 18, 2014, the PHMSA inspector randomly selected one detector at the San Juan Compressor Station building for the field test. During the test, the gas detector was activated by applying a known concentration of gas in air to the respective sensor. An emergency shut-down alarm was acknowledged at the control room. However, the gas detector failed to initiate the visual alarm system (strobe lights) inside and outside of the building. The visual alarm system (strobe lights) was found not operational.

EPNG Response 6:

Following the inspection on June 18, 2014, an investigation into the visual alarm system failure was conducted. Remedial actions were taken, and the system was tested successfully on August 8, 2014. For clarity, EPNG notes that although the compressor station emergency system was designed with a visual alarm system, the station itself was not designed and constructed under Kinder Morgan Engineering Design Manual E0200 – *Compression.* Therefore this design standard cannot be applied to this facility retroactively.

Item 7: §192.707 Line markers for mains and transmission lines.

(a) Buried pipelines. Except as provided in paragraph (b) of this section, a line marker must be placed and maintained as close as practical over each buried main and transmission line:

(1) At each crossing of a public road and railroad; and

(2) Wherever necessary to identify the location of the transmission line or main to reduce the possibility of damage or interference.

EPNG failed to place and maintain pipeline markers as close as practical over each buried transmission line at each crossing of a public road as required by §192.707(a)(1).

Kinder Morgan Procedure O&M 205 *Pipeline Markers and Cover*, section 3.1.1 *Buried Pipelines*, paragraph 3.1.1.2 *All Buried Pipelines (except as covered in 3.1.1.3 Alternative MAOP, Waiver, or Special Permit pipelines)* states,

"After verification of pipeline location, place line markers as close as practical over each buried pipeline, on each side of the edge of public roads, railroads, and highway rights-of-way. Consider placing additional signs in areas where third party damage to the pipe is possible..."

The PHMSA representative noticed line markers on Line 2121 within the median of Marina Road were not installed where the pipeline crosses underneath Hualapai Drive and Oliver Drive inside Bullhead City limits.

EPNG Response 7:

Although the Line Markers were not present on the day of the inspection, EPNG maintains line markers in compliance with O&M Procedure 205 – *Pipeline Markers and Cover* and 49 CFR 192.707. The two line marker installation locations specified are in an unpaved median area where traffic is known to illegally cross over and damage or destroy line markers. Line Markers were reinstalled at this location the day after discovery. In addition, because the median in this area is not protected from vehicular traffic, this location is patrolled by EPNG on a regular basis and when markers are found damaged or missing they are replaced promptly. EPNG is in the process of evaluating the use of flush to the ground markers in these locations.

Item 8: §192.735 Compressor stations: Storage of combustible materials.

(a) Flammable or combustible materials in quantities beyond those required for everyday use, or other than those normally used in compressor buildings, must be stored a safe distance from the compressor building.

EPNG failed to store a large quantity of foam cleaning pigs (flammable/combustible materials) a safe distance from the compressor building.

The Kinder Morgan Procedure O&M 119 *Flammable and Combustible Liquid Storage*, section 3.4.4 Storage in Compressor Buildings states,
"Flammable or combustible materials in quantities beyond those required for a day's use or other than those normally used in compressor buildings shall not be stored in compressor buildings."

During the field inspection at the Williams Compressor Station, the PHMSA representative found a large quantity of foam cleaning pigs stored inside the C Plant Building. The C Plant Building was the active compressor unit at the time of the inspection. The foam cleaning pigs are flammable combustible materials.

EPNG Flagstaff personnel promptly moved the foam pigs out of the C Plant Building during the week of July 21, 2014.

EPNG Response 8:

As noted in NOPV Item 8, EPNG station personnel promptly moved the foam pigs a safe distance from the compressor building. Based on this finding, EPNG area operations management have reviewed procedures with EPNG station personnel to ensure that the requirements of O&M Procedure 119 - *Flammable and Combustible Liquid Storage* and 49 CFR 192.735 are followed.

Item 9: §192.739 Pressure limiting and regulating stations: Inspection and testing.

(a) Each pressure limiting station, relief device (except rupture discs), and Pressure regulating station and its equipment must be subjected at intervals not exceeding 15 months, but at least once each calendar year, to inspections and tests to determine that it is-

(3) Except as provided in paragraph (b) of this section, set to control or relieve at the

correct pressure consistent with the pressure limits of §192.201(a);

EPNG failed to demonstrate the Relief Valve on the Auxiliary Generator at the Roswell Station was set at the correct pressure.

Kinder Morgan Procedure O&M 703 *Pressure Limiting and Relief Devices and Inspections*, section 3.1 MAOP, MAEP, *and Set Points* states,

"Each facility shall include adequate overpressure protection in its original design, including:
- *MAOP documentation*
- *Overpressure protection equipment and associated documentation*
- *Set points for each device…"*

On July 23, 2014, the PHMSA inspector randomly selected a first cut fuel relief valve at the Roswell Station to verify the set point in the field. According to Kinder Morgan's last test on 8/13/2013, the relief valve #0043 set point was left at 178 psig. During the field inspection, the PHMSA inspector observed the relief valve fail to relieve pressure at 200 psig. As a result, Kinder Morgan personnel isolated this relief valve by lock out/tag out.

On July 27, 2014, Kinder Morgan responded via email which stated "As of Friday, July 25, 2014, Lucas Moreno and Michael Bruner rebuilt the pilot then checked the Relief Valve operation twice. Each time, the valve relieved properly at 178 psig. Lock out/tag out was removed and the auxiliary generator was returned to service".

EPNG Response 9:

As noted in NOPV Item 9, EPNG retested and verified that the relief valve was set and relieving at the correct set pressure of 178psig. EPNG will test, document and correct any observed deficiencies found during the annual inspection intervals as required by *O&M Procedure 703 – Pressure Limiting and Relief Devices and Inspections* and 49 CFR 192.739.

Item 10: §192.743 Pressure limiting and regulating stations: Capacity of relief devices

(a) Pressure relief devices at pressure limiting stations and pressure regulating stations must have sufficient capacity to protect the facilities to which they are connected. Except as provided in §192.739(b), the capacity must be consistent with the pressure limits of §192.201(a). This capacity must be determined at intervals not exceeding 15 months, but at least once each calendar year, by testing the devices in place or by review and calculations.

EPNG failed to determine the necessary capacity of the relief devices at intervals not exceeding 15 months, but at least once each calendar year for the following devices:

1) Kat Generator Fuel Gas at Lincoln 6552 Station (Reference Drawing/Record Number: 1001-0849) – EPNG failed to verify the relief valve orifice ID and the outlet size. As a result, the capacity calculation was found to be inaccurate for the calendar years 2011, 2012 & 2013. EPNG's investigation to this issue was initiated after the PHMSA inspector's findings. This was corrected on 10/14/2014 and the capacity was found adequate.
2) 1st Cut for Generator Fuel at Rio Vista 6577 Station (Reference Drawing/Record Number: 1001-2215) – EPNG failed to provide capacity calculations for the

calendar years 2011, 2012 & 2013. EPNG's investigation was initiated after the PHMSA inspector's findings. This was corrected on 10/13/2014 and the capacity was found adequate.

3) Generator Fuel Gas at Bondad 6210 Station (Reference Drawing/Record Number: 1000-8383) – EPNG failed to provide regulator calculated/input capacity calculations for the calendar years 2011, 2012 & 2013. EPNG found and corrected this on 10/15/2014 and the capacity was found adequate.

4) Line 1300/1301 – Women's Correctional Facility –DPC 20596 – MP 331+4669 Regulator 1 Relief Valve 1 at Gallup 6538 Mainline Device (Reference Drawing/Record Number: 1001-2497 & 1001-2498) - EPNG failed to provide capacity calculations for the calendar years 2011 & 2012. Relief valve capacity summary sheet for 2013 was based on assuming relief valve is series 80 type 81 with orifice ID= 8 and required verification of relief valve data. This issue was verified as a result of PHMSA audit and corrected on 10/14/2014 and the capacity was found adequate.

5) Turbine 2 Expansion Gas at White Rock 6597 Station (Reference Drawing/Record Number: 1000-8405) – EPNG failed to verify the Inlet Pressure and MAOP upstream during calendar years 2011 and 2013. As a result, the capacity calculation was found inaccurate (based on 10/29/2014 report). EPNG did not verify the capacity calculation in 2012. EPNG corrected this on 10/15/2014 and the capacity was found adequate.

EPNG Response 10:

Refer to *EPNG CO Item 2 Response* above.

Item 11: §192.805 Qualification program.

Each operator shall have and follow a written qualification program. The program shall include provisions to:

(a) Identify covered tasks;

EPNG has failed to develop and include a covered task or tasks in its Operator Qualification Plan for loading, launching, receiving and unloading in-line inspection (ILI) smart tools used to perform integrity assessments to meet the requirements of §192.937(c)(1) and other in-line tools used for cleaning, batching, etc.

Loading, launching, receiving, and unloading in-line tools are covered maintenance tasks and meet the four part test required by §192.801(b). The loading, launching, receiving, and unloading functions of running an ILI tools is performed on a pipeline facility, is an operations and maintenance task, is performed as a requirement of this part within the integrity management requirements, and it affects the operations and integrity of the pipeline.

When the PHMSA inspector inquired about a covered task(s) for loading, launching, receiving and unloading in-line inspection tools, EPNG responded via email and stated Legacy El Paso and Kinder Morgan natural gas pipelines do not have a specific task for launching and receiving in-line inspection tools. EPNG further stated that the company uses a combination of natural gas pipeline operator qualification tasks for in-line tool inspection projects. Subsequently, the PHMSA inspector requested EPNG to provide specific covered tasks that encompass the steps required for pigging operations such as isolating pipeline barrels, relieving pressure, inserting or removing internal devices, pressurizing barrel and launching/receiving internal devices. EPNG identified the following covered tasks:

- *004.01.01: Corrosion Monitoring – Atmospheric, External, and*
- *Internal: General;*
- *04.01.02: Corrosion Monitoring – Atmospheric, External, and*
- *Internal: Offshore Pipelines;*
- *08.01.01: Locating pipelines;*
- *14.10.01: Line Markers;*
- *14.11.03: Pipeline Shutdown, Startup or Pressure Change;*
- *Operating Identified Valve(s);*
- *14.20.01: Valve Maintenance: Inspection & Partial Operation,*
- *14.20.02: Valve Maintenance: Maintenance;*
- *18.01.01: Pressure Regulating, Limiting, & Relief Device –*
- *O&M; and*
- *27.01.1: Gas control.*

Upon review, PHMSA inspector learned these tasks do not encompass the training and qualification requirements specific to loading ILI tools, launching, receiving, and unloading these tools from both in-service and out of service lines.

Specifically, 004.01.01, 04.01.02, 08.01.01, 14.10.01, 14.11.03, 14.20.01. 14.20.02, 18.01.01 and 27.01.01 did not encompass those steps required for pigging operations. Specifically they did not have requirements for identifying the procedures, practices, and equipment needed for conducting pigging operations; the identification of associated valves; steps for associated isolation and lockout/tagout (LOTO) procedures (isolating the barrel from pipeline); relieving pressure within the barrel and/or, inserting or removing internal devices into/from the barrel, pressurizing the barrel to pipeline pressures; launching, monitoring, and/or receiving/removing ILI tools; nor realigning all identified valves to normal operations. These covered tasks did not reflect the marked differences in pigging operations on in-service and out-of-service lines such as use of product to propel the ILI tool and specific Abnormal Operating Conditions that individuals performing loading, launching, receiving, and unloading need to be qualified in.

The PHMSA inspector reviewed the Kinder Morgan Procedure O&M 235: *Pigging Operations* (Revised date 2006-01-01), section 4 Training which states, *"Review this procedure and other relevant procedures before pigging projects. Document all training in the employee's local file"*.

No covered task in The Kinder Morgan Operator Qualification Program Appendix A *Table of Gas Covered Tasks* (Revised date: 4/30/2014) reference procedure O&M 235.

The Kinder Morgan Procedure O&M 916 In-Line Inspections does not reference covered task(s) that are necessary for qualification to perform ILI runs.

Also, the PHMSA inspector noted on 4/1/2013, EPNG reported an Abnormal Operation Incident # 201304017437 (EPNG Dimmitt Station unit 2 discharge relief valve event) due to improper block valve operation during pig launching operation at 5793 Springlake, TX. The root cause investigation performed by EPNG attributed the incident to a lack of knowledge.

EPNG Response 11:

Refer to *EPNG CO Item 3 Response* above.

Item 12: §192.805 Qualification program.

Each operator shall have and follow a written qualification program. The program shall include provisions to:

(b) Ensure through evaluation that individuals performing covered tasks are qualified;

EPNG failed to ensure through evaluation an employee was qualified to perform a covered task.

The Kinder Morgan OQ Program section 1 Scope, second paragraph states,

"...KM's OQ Program is designed to ensure that all individuals working on KM's DOT-regulated pipeline facilities are OQ qualified to perform specific covered tasks, to document that qualification and to reduce the probability and consequences of incidents and accidents..."

Also, section 3.1.2 Initial OQ Qualification states,

"Individual(s) will receive training, as appropriate, in preparation for initial qualification evaluations, as part of KM's training program. Trainees will not be allowed to independently perform covered tasks until qualification evaluations are passed."

While reviewing records associated with an Encroachment/One Call ticket, the PHMSA inspector observed that EPNG received a line-locate request (ticket #2013500358) on 12/9/2013 with the work start date on 12/11/2013. While installing a water line, the contractor uncovered 2 feet of 30" pipeline. An EPNG employee conducted the visual inspection of the external coating on 12/9/2014. The employee completed Form OM200-02: *Pipeline Examination Report* indicating he visually inspected the coating and found it in good condition. The PHMSA inspector reviewed the qualification records for the individual and found the individual was not qualified to perform this covered task. EPNG failed to ensure through evaluation that the employee was qualified to perform the covered task. The covered task the employee was unqualified for is task 004.01.03 *Visual Inspection of Buried Pipe and Components When Exposed*. EPNG stated that the employee was qualified on covered task 14.09.01: Inspection: Compliance with Procedures. When the PHMSA inspector reviewed the "Training Modules" for this covered task, it did not encompass those steps required for the inspection of buried pipe and components when exposed.

According to Kinder Morgan OQ Program Appendix A: *Table of Gas Covered Tasks*(Revised 04/30/2014), covered tasks 04.01.03 references Kinder Morgan Procedures O&M 903: *External Corrosion Control for Buried or Submerged Pipelines*, and O&M 918: *Inspecting for Atmospheric Corrosion*; whereas covered task 14.09.01 references Kinder Morgan Procedures O&M 204: *Construction Near Company Facilities*, Kinder Morgan Construction Inspection Manual *Essential Requirement of the Pipeline Inspector* and C1040: *Unloading, Hauling, and Stringing Materials*.

If aforementioned covered task 004.01.03 was performed by a non-qualified individual, Kinder Morgan's OQ Program Appendix A *Table of Gas Covered Tasks* (revised 04/30/2014) requires a span of control of a one to one. According to the inspection documentations provided by KM, a qualified employee was not present to observe or to direct this individual at the work site.

EPNG Response 12:

EPNG will ensure that the requirements of *Kinder Morgan OQ Program* and 49 CFR 192.805 are followed, and that only Operator Qualified employees perform covered tasks.

Thank you for your consideration of this information. As detailed above, EPNG requests that PHMSA modify the deadlines in Item 4 of the Consent Order. Please contact Reji George at 713-420-5433 or me at 713-369-8463 should you wish to discuss the information provided above.

Sincerely,

Gary Buchler
Chief Operating Officer
Kinder Morgan Natural Gas Division

cc: Jorge Torres, Vice President, Engineering
Ken Grubb, Vice President, Operation
Reji George, Director, Compliance / Codes and Standards
Toby Fore, Director, Engineering
Philip Baca, Director, Operations
Frank Causey, Operations Supervisor, PHMSA Southwest Region
Kumar Desai, Staff Engineer/Inspector, PHMSA Southwest Region
Greg Taylor, Interim Pipeline Safety Manager, Arizona Corporation Commission

Attachments: Kinder Morgan OQ Task 14.11.05 – Launching and Receiving Internal Devices