Crestwood™

801 Cherry Street
Suite 3800, Unit 20
Fort Worth, TX 76102

P: (817) 339.5400
F: (817) 339.5401
www.crestwoodlp.com

March 13, 2015

Mr. Byron Coy, PE
Director, Eastern Region
Pipeline and Hazardous Materials Safety Administration
820 Bear Tavern Road, Suite 103
West Trenton, NJ 08628

RE: Notice of Amendment CPF 1-2015-1001M Inspection

Dear Mr. Coy,

In regard to the New York State Department of Public Service inspection of Arlington Storage Company, LLC's ("Arlington Storage") Seneca Lake gas storage facilities in Watkins Glen, New York that occurred between September 1 and October 31, 2013, and the subsequent Notice of Amendment dated January 13, 2014 ("Notice") sent to Crestwood Midstream Partners LP ("Crestwood"). Arlington Storage is an indirect subsidiary of Crestwood and owner and operator of the Seneca Lake gas storage facilities in Watkins Glen, New York.

Arlington Storage did not contest the Notice and is submitting this response to the Notice within the 90 day period specified by the Notice.

- Subsequent to a merger in October 2013 of Crestwood with and into Inergy Midstream, L.P., operations of facilities have been consolidated and combined, and Crestwood's environmental, safety, and regulatory compliance management has and continues to work to implement company-wide compliance programs. As a part of this process, Crestwood is diligently working toward adopting and implementing an Operations and Maintenance Manual with a consistent format for all pipeline locations.

- The Operations and Maintenance Manual for Arlington Storage's Seneca Lake gas storage facilities, which was the document reviewed by NYSDPS, is currently being revised, and amended provisions are set out as a part of our response to the noted inadequacies of the prior Arlington Storage O&M Manual.

On the basis of the 2013 inspection PHMSA identified the "apparent inadequacies found within ASC's plans or procedures," as described below:

1. ASC'S O&M Procedure 906 "was inadequate because the procedure failed to define "corrosive gas" as prescribed in §192.475(a). It did not clearly define what actions need to be taken if corrosive gas or its constituents are discovered."

Response: Prior to transporting any gas, the gas will be tested to determine if the gas is corrosive (sour gas > 4ppm or acid gas > 3 MOL% or more of CO2 or some amount of H2S less than 4 PPM or a combination of both).
Any gas found to be corrosive will not be transported until its corrosive effects on the pipeline can be evaluated. Procedures to reduce the effects of the corrosive nature of the gas will be developed and approved by a Corrosion Professional. The procedures will be followed while transporting corrosive gas and will include monitoring as outlined below.

Whenever any pipe is removed from the pipeline for any reason, the internal surfaces must be visually inspected for evidence of corrosion. **Form OPS.13** "Exposed Pipe Inspection Report" or equivalent shall be used for these inspections.

The Arlington Storage O&M Manual is being revised at Section 6.8.2 to include definitions of Sour Gas and Corrosive Gas and the actions to be taken if corrosive gas or its constituents are discovered, as follows:

"6.8.2 INTERNAL CORROSION STANDARDS

During design of a steel pipeline segment certain determinations of transported material must be made and corrosion mitigation steps considered. The following process will be utilized by the company in evaluating internal corrosion possibilities:

Definitions

1. "Sour Gas" will assume the gas has more than 4 PPM of H2S within the gas stream on a continuing basis.
2. "Acid Gas" will assume that the gas is a wet stream and contains 3 MOL% or more of CO2.
3. Design will recognize and consider that corrosive tendencies of sour service or acid gas service is magnified at higher levels of contaminates, at higher flowing temperatures, and in the presence of water.

Process

1. Prior to final design, gas to be transported will be analyzed by chromatographic analysis or other means to determine levels of H2S and CO2.
2. Determination of moisture content of the gas stream will be made (Level may be due to operational consideration and/or contractual consideration)
3. Based on the results of the foregoing tests, the determination of whether additional mitigation steps should be made and documented. Mitigation steps identified and initiated will be monitored and documented to verify that corrosion on pipeline facilities will not affect its safe operation or additional steps must be identified and taken.

In general, sour gas or acid gas in excess of the concentration stated above and in the presence of free or entrained water will require that corrosion coupons (or other suitable inspection means) be installed within the pipeline to measure corrosion as required by 49 CFR 192.477. Inspection of the corrosion monitoring device will be consistent with

Section 2.15.2.2."

2. ASC's O&M Procedure 906 "was inadequate because procedure failed to clearly define what actions are to be taken if internal corrosion is discovered during an inspection as prescribed in §192.475(b)(3)."

Response: If internal corrosion is found, adjacent pipe must be investigated, by visual inspection, to determine the extent of the internal corrosion. Pipe will be replaced to the extent required by Section 2.15.4.1 of this manual and steps will be taken to minimize further internal corrosion.

The Arlington Storage O&M Manual is being revised to include more detailed instructions to monitor internal corrosion, as follows:

"2.15.2 INTERNAL CORROSION CONTROL [§192.475]

Prior to transporting any gas, it will be tested to determine if the gas is corrosive.

Any gas found to be corrosive will not be transported until its corrosive effects on the pipeline can be evaluated. Procedures to reduce the effects of the corrosive nature of the gas will be developed and approved by a Corrosion Professional. The procedures will be followed while transporting corrosive gas and will include monitoring as outlined below.

Whenever any pipe is removed from the pipeline for any reason, the internal surfaces must be visually inspected for evidence of corrosion. **Form OPS.13** "Exposed Pipe Inspection Report" or equivalent shall be used for these inspections.

If internal corrosion is found, adjacent pipe must be investigated, by visual inspection, to determine the extent of the internal corrosion. Pipe will be replaced to the extent required by Section 2.15.4.1 of this manual and steps will be taken to minimize further internal corrosion."

3. ASC's O&M Procedure 906 "was inadequate because the procedure fails to clearly define when coupons or other suitable devices are required as prescribed in §192.477. In addition the procedure does not provide information as to where these devices would need to be installed and there are no instructions on the frequency that these devices would need to be inspected."

Response: If corrosive gas is being transported, it will be mitigated as described above. Corrosion effects will be monitored by internal monitoring devices such as, but not limited to, coupons, ER probes, LPR probes, and/or H probes. Locations for placement of monitoring devices should be selected for the worst case scenario. Suggested placement locations may include, but not limited to, low points where fluids may collect, locations of turbulent flow where multiple lines may converge, where leaks have occurred in the past, etc. If utilized, monitoring devices will be inspected at intervals not exceeding 7 1/2 months, but at least twice each calendar year.

The Arlington Storage O&M Manual is being revised at Section 2.15.2.2 to describe when coupons or other suitable devices are required, information as to where these devices are to be installed, and inspection frequencies, as follows:

"2.15.2.2 INTERNAL CORROSION MONITORING [§192.477]

If corrosive gas is being transported, it will be mitigated as described above. Corrosion effects will be monitored by internal monitoring devices such as, but not limited to, coupons, ER probes, LPR probes, and/or H probes. Locations for placement of monitoring devices should be selected for the worst case scenario. Suggested placement locations may include, but not limited to, low points where fluids may collect, locations of turbulent flow where multiple lines may converge, where leaks have occurred in the past, etc. If utilized, monitoring devices will be inspected at intervals not exceeding 7 1/2 months, but at least twice each calendar year."

In addition, the Arlington Storage O&M Manual is being revised at Section 2.15.2.1 to provide information as to where suitable devices would need to be installed, as follows:

"2.15.2.1 <u>INTERNAL CORROSION DESIGN & CONSTRUCTION</u> [§192.476]

Each new regulated pipeline and each replacement of pipe, valve fitting or other line component must have features incorporated into its design and construction to reduce risk of internal corrosion. There are exceptions to applicability. This does not apply to offshore pipelines and pipelines installed or line pipe, valve, fitting or other line component replaced before May 23, 2007. When a change is made to the configuration of an existing pipeline, the impact of the change on internal corrosion risk downstream must be evaluated. Monitoring of internal corrosion and a means for removal of liquids must be provided for in this evaluation.

Records reflecting the evaluation for design must be prepared and supported by drawings, engineering calculations or other construction records and maintained for life of pipeline."

4. ASC's procedures for Atmospheric Corrosion Control "were inadequate in that they did not adequately detail how they meet the requirements prescribed in §192.479.

<u>Response</u>: Each above ground portion of the pipeline system that is exposed to the atmosphere will be cleaned and coated with an appropriate material to prevent atmospheric corrosion unless it is apparent that non-coating will produce only a slight surface oxide and will not affect the integrity of the pipeline before the next inspection. Nonetheless, all onshore soil to air interfaces must be coated. Company's paint and coating specifications, if available, may be referenced for approved material.

The Arlington Storage O&M Manual is being revised at Section 6.8.3 to include more detailed procedures for atmospheric corrosion control, as follows:

"6.8.3 ATMOSPHERIC CORROSION PROTECTION STANDARDS

During the design phase of pipeline construction the atmospheric conditions within the area where above ground installations will be made must be considered and documented. Some areas of construction may never be subject to atmospheric corrosion (Wyoming as an example) and other areas may incur quick and severe atmospheric corrosion (South Louisiana as an example). Nonetheless, the company as a prudent operator will utilize the following process in its construction techniques to address atmospheric corrosion.

1. Onshore-Each "soil to air" location where buried pipe exits the soil into the open air will be coated with suitable coating to an elevation of at least 6" above ground level. Coating may be of the same type that exists on the underground piping providing that this coating is not harmed or deteriorated by UV rays or it may be a standalone type coating or a combination of both. Regardless of coating material type, manufacturer installation instructions will be followed when installing.
2. Offshore – Each regulated pipe installed within the "splash zone" or at "deck penetrations" will be coated with material appropriate for this severe application. Typically these locations may be coated with two part epoxy type coating but this type coating is not a requirement. However, the coating selected must be suitable for the service.
3. Other Locations – Generally, other above ground locations, whether required or not, will be coated at the time of construction with a coating suitable for the prevention of atmospheric corrosion. Coatings will be selected from products available at the time of construction and approved and documented by the design engineer."

5. ASC's procedures for Atmospheric Corrosion Control Inspections "were inadequate because it lacked detailed instructions to monitor atmospheric corrosion."

Response: Each onshore portion of pipeline that is exposed to the atmosphere will be inspected at intervals of three years not to exceed 39 months. More frequent inspections may be conducted, such as during pipe to soil inspections, at the discretion of the pipeline supervisor or designee. The Pipeline Supervisor or designee will ensure that remedial measures are taken whenever atmospheric corrosion is detected. ***Form OPS.23*** "Atmospheric Corrosion Inspection Report" or equivalent will be utilized to document the inspection.

Areas that may be especially susceptible to atmospheric corrosion and will require special attention include:

- Soil/air interfaces
- Under thermal insulation
- Under disbonded coating
- Around pipe supports

The Arlington Storage O&M Manual is being revised to include more detailed instructions for monitoring atmospheric corrosion, as follows:

"2.15.3 ATMOSPHERIC CORROSION CONTROL [§192.479 and 192.481]

Each above ground portion of the pipeline system that is exposed to the atmosphere will be cleaned and coated with appropriate material to prevent atmospheric corrosion unless it is apparent that non-coating will produce only a slight surface oxide and will not affect the integrity of the pipeline before the next inspection. Nonetheless, all offshore splash zones and onshore soil to air interfaces must be coated. Company's paint and coating specifications, if available, may be referenced for approved material.

Each onshore portion of pipeline that is exposed to the atmosphere will be inspected at intervals of three years not to exceed 39 months and offshore portions of exposed pipelines will be inspected once per calendar year, not to exceed 15 months. More frequent inspections may be conducted, such as during pipe to soil inspections, at the discretion of the pipeline supervisor or designee. The Pipeline Supervisor or designee will ensure that remedial measures are taken whenever atmospheric corrosion is detected. **Form OPS.23** "Atmospheric Corrosion Inspection Report" or equivalent will be utilized to document the inspection.

Areas that may be especially susceptible to atmospheric corrosion and will require special attention includes:

- Soil/air interfaces
- Under thermal insulation
- Under disbonded coating
- Around pipe supports
- Within splash zones
- At deck penetrations
- On over water spans"

We believe these responses and revisions address each of the items identified in the Notice of Amendment as required by 49 CFR §192.

Should you have any questions concerning the above, please contact me at 817-339-5498 or alice.ratcliffe@crestwoodlp.com.

Respectfully,

Alice Ratcliffe

Alice Ratcliffe
Pipeline Compliance Manager

Attachments:

Form OPS.13 Exposed Pipe Inspection Report

Form OPS.23 Atmospheric Corrosion Inspection Report

OPS.13

Crestwood

Exposed Pipe Inspection Report

Field Office: ______________________ Date: __________

System Name: ______________________

Location: ______________________

GENERAL INFORMATION

Pipe Inspector's Name: Employer: __________

Depth of Cover: ________ Wall Thickness: ________ Pipeline size: ________ Operating Pressure: ________

Reason for Exposure: ______________________

Age of pipeline (if known): __________

EXTERNAL CONDITION

General description of exposure: ______________________

Did you observe any evidence of corrosion? ________ General: ________ Localized ________

If localized corrosion- Location of pits: ________ Max pit depth: ________

Additional Comments: ______________________

Type of Coating ______________________

Condition of Coating: Good ☐ Fair ☐ Poor ☐

If Coating has failed or is about to fail, state reason: ______________________

Examples: poor installation, wrong coating for type of service, excavation damage, defective material, rock or backfill damage, exposed to excessive heat, etc.

List valves or fittings that have been exposed: ______________________

Were they coated? ________ Did you observe any problems? ________

If so, what kind: ______________________

Cathodic Protection data; P/S at surface: ________ P/S at pipe depth: ________

Person performing test: ________ Date Taken ________

INTERNAL

(If exposed metal pipe allows for internal inspections, it must be inspected> If significant corrosion is apparent, adjacent exposed metal pipe internal walls must be inspected also.)

Describe internal surface of exposed pipe ______________________

Did you observe any evidence of corrosion ________; If so, classify:

General: ________, Localized ________, Other ________

Description: ______________________

Was coupon retained: ________ (if coupon retained ID 12 O'clock, position and flow direction)

Maximum Pit Depth: ________

Repairs Made

Describe repairs made ______________________

Additional Comments: ______________________

Note: Perform B31G or Rstreng calculation if corrosion is found.

(Use back of form or attach additional pages for additional information, comments and sketches/drawings)

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Atmospheric Corrosion Inspection Report

Field Office: ______________________ Field: ______________________

Performed By: ______________________ Pipeline Segment: ______________________

Title: ______________________

Date	Location Description	Pipe Size	Type of Exposure (I.E. Meter run, Block Valve)	Coating Condition	External Corrosion Present (Y/N)	If Yes, General or pitting	Max Depth	Wall Thicknes	*Maintenance Required	Remarks

* If signifigant corrosion is found repairs or recalculation of MAOP are required (49 CFR Part 192.485)