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Dominion

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May 15, 2015

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

RE: CPF 1-2015-1007M

Dear Mr. Coy,

This letter is the formal response by Dominion Transmission, Inc. (DTI) to Notice of Amendment (NOA) CPF 1-2015-1007M dated April 15, 2015, which identified five (5) concerns in DTI's Operations and Maintenance procedures that require clarification or further explanation. The following are DTI's responses to each:

1. **§192.915 What knowledge and training must personnel have to carry out an integrity management program?**

(a) …

(b) Persons who carry out assessments and evaluate assessment results. The integrity management program must provide criteria for qualification of any person-

(1) …

(2) Who reviews and analyzes the results from an integrity assessment and evaluation;

DTI's integrity management program is inadequate in that it does not provide criteria for the qualification of any person who reviews and analyzes the results from an integrity assessment and evaluation.

During the inspection, PHMSA reviewed DTI procedure "Integrity Management Program for Gas Transmission Pipelines, Section 18, Training and Operator Qualification, revised September 1, 2012."

1. Section 18.2 references §192.915(b)(2) and states in part that "DTI will provide criteria

for the qualification of any person [w]ho reviews and analyzes the results from an integrity assessment and evaluation."

2. Section 18.4 (Procedures and Supporting Documents) of the procedure references a supporting document titled "IMP Job Descriptions and Qualifications." The referenced document defines the essential functions, qualifications and requirements of a pipeline integrity engineer.

The procedure indicates that the pipeline integrity engineer is "[r]esponsible for analyzing the data provided by the in-line inspection contractor looking for defects that require further analysis." The procedure does not provide details on the training requirements for the pipeline integrity engineer conducting said analysis, such as what courses are required, what topics must be covered, how long is the training, and how the qualifications of the pipeline integrity engineer are evaluated.

DTI Response:

DTI is proposing to add the following requirements to the "Qualifications / Requirements:" in the "IMP Job Descriptions and Qualifications" document

- Responsible for analyzing the data provided by the in-line inspection contractor looking for defects that require further analysis. The following requirements must be met to allow for adequate review of ILI assessment data.
    - Attend at least one industry training, approximately 18 hours, on In-line Inspection (e.g. SGA – Practical In-line Inspection, SGA – Advanced In-line Inspection, Pipeline Pigging and Integrity Management (PPIM) - Pigging and In-Line Inspection, etc.), that cover these or similar topics: Principles of Operation of ILI Tools, Data Handling and Analysis, and Pipeline Defects and Analysis, or:
    - Complete "On the Job Training" with ILI Subject Matter Expert (SME) and document the ILI data review and the process used to conduct the review of data. During this process, the ILI SME will assess the competency of the person and will determine when the person is competent to complete ILI assessments individually. Technical Training will maintain these records.

2. **§192.911 What are the elements of an integrity management program?**
   (a) …
   (b) …
   (c) An identification of threats to each covered pipeline segment, which must include data integration and a risk assessment. An operator must use the threat identification and risk assessment to prioritize covered segments for assessment (§ 192.917) and to evaluate the merits of additional preventive and mitigative measures (§ 192.935) for each covered segment.

DTI's integrity management program is inadequate in that it fails to describe how the program integrates data from ILI results with other data as per 192.917(b).

During the inspection, PHMSA reviewed DTI Procedure "Integrity Management Program for Gas Transmission Pipelines, Section 5.4, Inline Inspection revised September 1, 2012." Section 5.4, step 50 states that "[t]he Pipeline Integrity Engineer integrates additional risk-factor data and new information with the assessment results . . . "

The procedure does not provide details as to what kinds of data must be integrated with ILI results such as what is described in ASME/ANSI B31.8S-Appendix A.

DTI Response:

DTI is proposing to add the following requirements to the DTI Procedure "Integrity Management Program for Gas Transmission Pipelines, Section 5.4. Inline Inspection:

- The Pipeline Integrity Engineer must integrate Inline inspection assessment data with the following data, as applicable: cathodic protection records, previous ILI assessment data, satellite/aerial imagery, GIS system, Transmission Field Inspection Reports (TFIR), CorrEval, and input from operations. ~~additional risk-factor data and new information with the assessment results using tools such as GIS (SAMS), TFIR Reports, Input from Operations, and available aerial photography (such as Google Earth) where appropriate~~. **(Step #50)**

3. **§192.605 Procedural manual for operations, maintenance, and emergencies**
   Each operator shall include the following in its operating and maintenance plan:
   (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.**

DTI's procedure for training the appropriate operating personnel to assure that they are knowledgeable of the emergency procedures and verify that the training is effective as per 192.615(b)(2) is inadequate.

During the inspection, PHMSA reviewed DTI Procedure Section: 110 / Emergency Plans SOP: 01 / Combined Emergency Plan revised 10/15/2012. Section II.B.2. states in part that "Dominion shall [c]onduct Emergency Plan training and testing annually not exceeding 15 months for all applicable personnel. Technical Training will maintain test results."

The procedure does not provide details as to what the training must include, such as mock drills, tabletop exercises, etc.; and how they verify that the training is effective.

DTI Response:

DTI currently requires applicable personnel to review the multiple Emergency Response Scenarios and Emergency personnel roles that are listed within the Combined Emergency Plan at least each calendar year, not to exceed 15 months. Applicable personnel are then tested on the response scenarios to ensure understanding of how to react to the various response scenarios. Therefore, DTI is proposing to modify the current procedure to include the following:

"Dominion shall [c]onduct Emergency Plan training by requiring applicable personnel to review the Emergency Response Scenarios listed in the Combined Emergency Plan and will test applicable personnel to ensure understanding of how to react to these scenarios. This training and testing will be conducted once each calendar year not exceeding 15 months for all applicable personnel. Technical Training will maintain test results."

4. **§192.605 Procedural manual for operations, maintenance, and emergencies**
   Each operator shall include the following in its operating and maintenance plan:
   (a) **...**
   (b) **Maintenance and normal operations. The manual required by paragraph (a) of this section must include procedures for the following, if applicable, to provide safety during maintenance and operations.**
      (1) ...
      (2) Controlling corrosion in accordance with the operations and maintenance requirements of Subpart I of this part.

DTI's procedure for controlling corrosion in accordance with the operations and maintenance requirements of Subpart I, paragraph 192.465(b) is inadequate.

During the inspection, PHMSA reviewed DTI Procedure Section: 070/ Corrosion Control SOP: 08 / Monitoring Cathodic Protection Levels revised 10/15/2012. Section III.A.2 – Specific Galvanic Cathodic Protection Work Measures, states in part that "When a **deficient** [emphasis added] reading is encountered during test-point monitoring, the extent of the problem area should be verified. If remedial work involves applying additional cathodic protection, the effectiveness of the corrective action should be verified by performing a close-interval survey, with a maximum spacing of 25 feet, over the defined problem area."

During the review of the rectifier monitoring test records, an abnormally high reading was discovered on a rectifier named "Unit 2 – Martin Road" in Inspection Unit #1411. The reading was dated March 2013 and showed 156.25 DC amps. Other readings showed values in the 10-20 DC amp range.

The procedure does not provide criteria for a "deficient" reading and does not provide detail on verifying the extent of the problem, such as how this should be done and who is responsible for the analysis.

DTI Response

To address the aforementioned concerns, the following changes have been made to DTI

Procedure Section: 070 / Corrosion Control SOP 08: Monitoring Cathodic Protection Levels and DTI's Corrosion Manual Section 5 – Cathodic Protection Testing and Monitoring and Section 6 – Stray Current Interference. In addition to the noted Procedure modifications, automatic notifications have been built into the Inspection Monitoring System (IMS) where e-mails are sent to the Pipeline Integrity Corrosion Group, to indicate a 50% increase or decrease in circuit resistance (ohms). This automatic notification prompts the Pipeline Integrity Corrosion Group to further investigate the reason for the change and to ensure adequate cathodic protection of the pipeline. The following example from the noted 156.25 DC amp, noted during the audit, demonstrate this added functionality.

A follow-up investigation would now be required with the noted 156.25 DC amp reading (41.469 volts/156.25 amps = 0.265 ohms), where the previous readings were 10-20 DC amp range (41.462 volts/10 amps = 4.1462 ohms). Another example why a 50% change is used in place of numerical limits is provided in the following example, where previous readings were four (4) DC amps (41.469 volts/4 amps = 10.367 ohms) were obtained and then a ten (10) DC amp (41.469 volts/10 amps = 4.147 ohms) value is obtained. The rectifier inspection has changed by 50% and further investigation would be prompted by an automatic e-mail forwarded by the (IMS) to the Pipeline Integrity Corrosion Group to further evaluate the reason for this greater than 50% change in circuit resistance.

The recommended procedural changes are noted in the underline redline shown below:

DTI Procedure Section: 070 / Corrosion Control
SOP 08: Monitoring Cathodic Protection Levels

II. MONITORING REQUIREMENTS

A. Each pipeline, including Company and customer-owned service lines required to be cathodically protected, shall be tested at least once each calendar year, at intervals not exceeding 15 months, to determine whether its cathodic protection levels meet the criteria of **Corrosion Control SOP 70-07 Cathodic Protection Criteria.** When annual testing indicates the cathodic protection does not meet a criterion as outlined in SOP 70/07, then the reading is considered deficient. Refer to Section 5.2.4 and 5.3.7 of the Corrosion Manual to identify when and what to do if the annual testing is deficient

C. Each cathodic protection rectifier or other impressed current power source shall be inspected six (6) times each calendar year, at intervals not exceeding 2½ months, to ensure proper operation. Refer to Section 5.4.4 of the Corrosion Manual to identify when and what to do if a rectifier or other impressed current power source is not operating properly. DTI may choose to make these inspections through the use of remote monitoring equipment.

NOTE: Oil-cooled rectifiers should be inspected for leaking oil. If the rectifier is leaking oil, refer to Environmental SOP 120-17 PCB - Response to PCB Spills.

D. Each reverse current switch, each diode, and each interference bond whose failure would jeopardize structure protection shall be electrically checked for proper performance six (6) times each calendar year, at intervals not exceeding 2½ months. Each other interference bond shall be checked at least once each calendar year, at intervals not exceeding 15 months. Refer to Section 6.5.3 of the Corrosion Manual to identify when and what to do if a reverse current switch, diode, or interference bond is not operating properly.

III. REMEDIAL MEASURES

A. Prompt remedial measures shall be taken to correct any deficiencies indicated by required monitoring. Remedial action should be completed within 15 months or by the next required test, inspection or electrical check, whichever is less. If it is not practical to perform and verify the effectiveness of remedial action within this time frame, a plan of action with a proposed time frame for implementation shall be developed and submitted to the Pipeline Integrity Section for approval. While Sections 5 and 6 of the Corrosion Manual provide detail on how to verify the extent of the problem, t~~T~~he following are some examples of general and specific remedial measures:

1. General Cathodic Protection Work Measures

   a. Verify proper operation of cathodic protection system.

   b. Apply or repair protective coating.

   c. Apply cathodic protection.

   d. Isolate electrically.

   e. Control stray currents.

   f. Other methods approved by Pipeline Integrity.

Corrosion Manual:	- **Section 5 – Cathodic Protection Testing and Monitoring** - **Section 6 – Stray Current Interference**

5.2.4 Deficient and Abnormal Measurements of Test Points on a Coated Pipeline

A test point deficiency is a measurement that does not satisfy the criteria defined in Section 5.1.2.

(a) Galvanic Protected Pipeline Deficiency

When a deficient measurement is observed, the corrosion technician is responsible for determining the extent of the problem area and perform the recommended remediation. The extent of the problem area can be determined by performing pipe to soil measurements along the pipeline to identify the sub-criterion area. The area corrosion technician is responsible for identifying the locations for remediation. Section 5.7.4 may be used to guide the corrosion technician with troubleshooting the system.

Additional cathodic protection may be recommended as a remedial action for the deficient location. Depending on the current requirement, proximity to other pipelines, and soil conditions, this may require either a galvanic or impressed current installation. If additional cathodic protection is installed, the effectiveness of the cathodic protection should be verified by a close interval survey not to exceed spacing of 25 feet. This data is then reviewed by the area corrosion technician and Pipeline Integrity area corrosion support person.

Other remediation methods include but are not limited to installation of additional isolation, recoating the pipeline, etc. These remediation methods should also be verified by a close interval survey to determine if additional cathodic protection is required to satisfy the criterion in Section 5.1.2

(b) Impressed Current Protected Pipeline Deficiency

For impressed current protected pipelines, when the annual test point measurement does not satisfy a criterion, the corrosion technician is responsible to review the rectifier system history to ensure the rectifier and anode bed system are functioning properly. Section 5.7.4 may be used to guide the corrosion technician with troubleshooting the system. If rectifier and anode beds are functioning as designed, then additional current may be required. If current output has been increased at one or more rectifiers, the change in rectifier output should be recorded on the appropriate form in DTI's Inspection Monitoring System (IMS). With the additional current the test point location must verify that a cathodic protection criterion has been achieved.

(c) Abnormal Measurements

Trending is important when performing pipe to soil measurements on an annual basis. There are cases explained in Section 5.1.5 that may cause measurement errors. Abnormal measurements are typically abrupt changes in the history of the test point location. For example, a test point location that traditionally obtained a polarized potential of between -900 mVcse and -1100 mVcse for several years. If the reading then becomes more negative than -1200 mVcse, there may be an indication of stray current as described in Section 6.2.2. A second example is a test point location that traditionally has measurements between -1150 mVcse and -1180 mVcse. If the measurement decreases to a -900 mVcse, it becomes an abnormal measurement. While abnormal measurements are not a deficiency, they should still be investigated to determine the reason for the abnormal read. The corrosion technician is responsible to identify trending within the data. When performing the annual test point monitoring, the previous inspection is displayed during the inspection to aid the corrosion technician to identify if there has been changes since the previous measurement.

5.3.7 Deficient and Abnormal Measurements of Test Points on a Bare Pipeline

(a) Galvanic Protected Pipeline Deficiency

As described in Section 5.3.5, bare pipe with active corrosion may only be "hot spot" protected with galvanic anodes at anodic areas. These anodic areas are not monitored by test points, but by electrical survey demonstrating Net Protective Current. A deficiency for a bare "hot spot" protected pipeline would be either the identification of an anodic area without a previously installed galvanic anode or when current to the pipeline cannot be verified at the location of an anode.

(b) Impressed Current Protected Pipeline Deficiency

A test point deficiency is a measurement that does not satisfy the criteria defined in Section 5.1.2. For impressed current protected pipelines, when the annual test point measurement does not satisfy a criterion, the corrosion technician is responsible to review the rectifier system history to ensure the rectifier and anode bed system is functioning properly. Section 5.7.4 may be used to guide the corrosion technician with troubleshooting the system. If rectifier and anode beds are functioning as designed, then additional current may be required. If current output has been increased at one or more rectifiers, the change in rectifier output should be recorded on the appropriate form in DTI's Inspection Monitoring System (IMS). With the additional current, the test point location must verify that a cathodic protection criterion has been achieved.

(c) Abnormal Measurements

Trending is important when performing pipe to soil measurements on an annual basis. There are cases explained in Section 5.1.5 that may cause measurement errors. Abnormal measurements are typically abrupt changes in the history of the test point location. For example, a test point location of a 100 mV protected bare line traditionally obtained a polarized potential of between -700 mVcse and -800 mVcse for several years. If the reading then becomes more negative than -1050 mVcse, there may be an indication of stray current as described in Section 6.2.2. A second example is a test point location that traditionally has measurements between -750 mVcse and -800 mVcse. If the measurement decreases to a -650 mVcse, it becomes an abnormal measurement. While abnormal measurements are not a deficiency as long as the 100 mV polarization is still achieved, they should still be investigated to determine the reason for the abnormal read. The corrosion technician is responsible to identify trending within the data. When performing the annual test point monitoring, the previous inspection is displayed during the inspection to aid the corrosion technician to identify if there has been changes since the previous measurement.

5.4.4 Monitoring and Maintenance

(c) Rectifier Measurement Deficiency

A rectifier deficiency is when the measurement of the output of the rectifier is zero (0) amps, unless the rectifier is "down for construction" described in section 5.4.4 (e) below. When zero amps are measured during a rectifier inspection, the corrosion technician is responsible for performing the troubleshooting of the rectifier as described in Section 5.4.5. Remediation should be completed by the next scheduled inspection. If a rectifier part needs to be ordered, then a waiver (Gen 6004) needs to be approved by the Pipeline Integrity Corrosion Group. The remediation for the deficiency shall be recorded in DTI's Inspection Monitoring System (IMS).

(d) Rectifier Abnormal Measurement

DC volts and DC amps are measured and recorded on the appropriate inspection monitoring system (IMS) form during the rectifier inspection. Using ohms law, the rectifier circuit resistance is calculated for each inspection in IMS. When the circuit resistance of a rectifier inspection has changed by 50% (either an increase or a decrease), the abnormal measurement indication is automatically forwarded by the IMS by e-mail, to the Pipeline Integrity Corrosion Group for review. The circuit resistance change may be caused by modifications in the pipeline system that required a decrease in cathodic protection current. An increase in circuit resistance may be caused by the factors described Section 5.7.4 (b). An increase or decrease in circuit resistance caused by output increase or decrease during an inspection is not a deficient measurement but may require a follow-up investigation to determine cause of change and to ensure adequate cathodic protection is being maintained. A deficient rectifier inspection is recorded only when a zero (0) amp measurement is obtained.

(e) Rectifier "Down for Construction"

For safety reasons, a rectifier may be "down for construction" while construction activities occur on the existing piping system. A rectifier that is "down for construction" will still need to have an inspection completed at the required intervals until the construction is complete. This inspection is recorded on the appropriate form in the IMS system.

Corrosion Manual Section 6 – Stray Current Interference

6.5.3 Interference Bond Deficiency and Abnormal Measurements

(a) Deficient bond measurements

A deficient bond measurement is when there are zero (0) amps flowing across the bond. A damaged bond wire in which there is no continuity will cause a deficient bond measurement. A deficient bond reading applies to both critical and non-critical bonds. The remediation for a deficient bond includes reinstalling the appropriate resistant bond at the location. The remediation must be recorded on the appropriate form in IMS.

(b) Abnormal bond measurements

During interference testing described in Section 6 of this manual, limits and directions of amperage are established to determine if the bond is critical and the amplitude of the current. Each site determines the amplitude of the current flow and direction. The interference testing is entered into the bond inspection form in IMS.

An abnormal bond measurement is when the amperage or the direction of current may have changed since the original interference testing. The amperage and/or direction may be directly related to rectifier malfunction for either the company or foreign rectifiers. When an abnormal bond measurement is obtained, the corrosion tech is responsible for contacting the foreign operator to determine if there has been a change in the system. For example, this change could be a damaged rectifier, damaged anode bed, or new rectifier installed on the system. Information regarding the abnormal bond measurement should be recorded on the appropriate form in IMS. If the abnormal measurement is due to a condition that is beyond DTI's control, the corrosion technician will continue to document the changes and determine if the bond is still necessary at the location.

5. **§192.605 Procedural manual for operations, maintenance, and emergencies**
   Each operator shall include the following in its operating and maintenance plan:
   (a) **…**
   (b) **Maintenance and normal operations. The manual required by paragraph (a) of this section must include procedures for the following, if applicable, to provide safety during maintenance and operations.**
      (1) …
      (2) **Controlling corrosion in accordance with the operations and maintenance requirements of Subpart I of this part.**

DTI's procedure for controlling corrosion in accordance with the operations and maintenance

requirements of Subpart I, paragraph 192.481 (b) is inadequate.

During the inspection, DTI provided the following procedures for monitoring pipe under thermal insulation:

1. DTI Procedure Section: 070 / Corrosion Control SOP: 16 / Atmospheric Corrosion revised 10/15/2012.
2. DTI Corrosion Manual, Sec. 3.6.4.2 (Rev 1/31/2013)
3. DTI Corrosion Manual Appendix 3.12 (Rev 1/31/2008)

PHMSA reviewed the procedures above and found the following inadequacies:

1. In the procedure noted below, DTI uses the term "*should*" in its procedures where the regulation requires the term "*must*."
    a. DTI O&M Sec. 070, SOP 16 Section VII.A. states that … Particular attention *should* be given to locations such as clamps … under thermal insulation…
    b. DTI Corrosion Manual, Sec. 3.6.4.2 (Rev 1/31/2013) states that … special attention *should* be paid to …
2. DTI Corrosion Manual, Sec. 3.6.4.2 (Rev 1/31/2013) states in part that:
    a. "During the atmospheric corrosion inspection special attention should be paid to bulging insulation, dripping moisture from the insulation, and/or rust stains are signs that moisture is forming under the insulation creating a corrosive environment. These signs should be recorded on the appropriate form." The procedure does provide guidance on how to provide "special attention" to determine the condition of the pipe surface under thermal insulation, such as by removal of a portion of the insulation when bulging insulation, dripping moisture from the insulation, and/or rust stains are observed.
    b. "Inspection ports should be incorporated in the design of new thermal insulation and facilities. If inspection ports exist, the plug should be removed and the coating and/or substrate should be examined for atmospheric corrosion," The procedure does not specify what must be done to determine the condition of the pipe surface under thermal insulation if the piping does not have inspection ports.
3. DTI Corrosion Manual Appendix 3.12 (Rev 1/31/2008) – Sec IV titled "Insulated Pipe / Vessel Inspections" states in part that "The exterior insulation of all insulated pipe and vessels shall be visually inspected at intervals stated above. Inspection shall include determinations of the condition of the exterior insulation. It is not necessary to remove any insulation if the temperature of the entire vessel shell is maintained sufficiently low or sufficiently high to prevent the condensation of moisture"

    The temperatures noted as "sufficiently low" and "sufficiently high" are not specified. In addition, the procedure does not specify which piping and vessels fall into this category, how they will ensure / document that the temperature of the pipe or vessel remains in the specified temperature range and what methods must be used to ensure that there is no corrosion under the insulation.

    The procedure also states in part that "Specific areas that should be inspected on insulated pipe or vessels include:
    A. All surfaces exposed to frequent hot/cold temperature cycling;
    B. Horizontal piping, particularly at joints or piping branches, and on the bottom of the

pipe;

C. Towers or other vessels at four inspection points around the tower/vessel with a 90 deg. separation and at two elevations near bottom and near top;
D. Wherever the insulation weather barrier has been mechanically damaged or removed such as the damaged insulation;
E. Wherever the insulation has changed shape or started to swell, indicating a possible rust buildup."

DTI does not specify which piping and vessels fall into the "frequent hot/cold temperature cycling" category, and what methods must be used to ensure that there is no corrosion under the insulation. In addition, the procedure does not specify what must be done to determine the condition of the pipe under thermal insulation wherever the insulation weather barrier has been mechanically damaged or removed such as the damaged insulation, or whenever the insulation has changed shape or started to swell.

DTI Response:

As a result of the 2013 PHMSA audit, held March 11 to April 5, 2013, DTI modified Section: 070 / Corrosion Control SOP: 16 / Atmospheric Corrosion during the 2013 annual SOP review to address the concern. The modifications to the SOP have been communicated and reviewed with personnel.

VII. DETERMINING AREAS OF ATMOSPHERIC CORROSION

A. The presence of atmospheric corrosion can best be detected by visual inspection. This may require ladders, scaffolds, hoists or other suitable means of permitting inspector access to the structure. Particular attention shall be given to locations such as clamps, rest plates, at pipe supports, in splash zones, at deck penetrations, sleeved openings, under thermal insulation, under disbonded coatings, spans over water, and air-to-soil interface areas.

DTI Corrosion Manual Section 3.6.4.2 Under Thermal Insulation has been modified to address the above mentioned concerns:

3.6.4.2 Under Thermal Insulation

Thermal insulation is used to reduce the amount of heat leaving the pipe surface, which would reduce the temperature of the material inside the pipe. At elevated temperatures, the pipe tends to sweat leaving moisture on the surface on the pipe. Having moisture under thermal insulation creates a corrosive environment. During the atmospheric corrosion inspection special attention ~~should~~ must be paid to bulging insulation, dripping moisture from the insulation, and/or rust stains are signs that moisture is forming under the insulation creating a corrosive environment. These signs ~~should~~ must be further investigated by removing the insulation to observe for corrosion and recorded on the appropriate form.

~~Inspection ports must be installed on insulated piping and vessels. However, they are not needed inside of buildings unless you see rust stain or bulging.~~ Inspection ports allow the pipe surface to be inspected under the thermal insulation. These ports are usually placed in locations where the moisture is most likely to form under the insulation and that are more susceptible to corrosion. Inspection ports allow the exterior surface of the pipe to be inspected for corrosion. If the pipe is externally painted the inspection port will allow the condition of the paint to be observed at that point on the pipe. Inspection ports should be incorporated in the design of new thermal insulation and facilities. If no inspection ports exist, then they must be installed.

Inspection ports must be installed on insulated piping and vessels, excpepet insulated piping and vessels located inside of a building or vessels ~~that have factory applied insulation~~that have the vessel shell maintain constant operation below 30°F or above 215 °F, per manufacturer specifications.~~-~~ Piping located within a building is less likely to come in contact with direct moisture. ~~Factory applied insulation on vessels, such as salt bath heaters, have well applied insulation.~~ During atmospheric corrosion inspections of all vessels, subject to CFR Part 192, particular attention shall be paid to locations where bulging, swelling, and rust bleed is occurring in the insulation. If these are identified during the atmospheric corrosion inspection, the insulation must be removed and the substrate must be inspected for corrosion. If missing or damaged weather barrier, then the substrate must be inspected for corrosion and the weather barrier shall be repaired or replaced.

~~During atmospheric corrosion inspections, the insulation on these vessels should be inspected for bulging, swelling, or rust bleed through the insulation. If bulging or rust bleed are identified during the atmospheric corrosion inspection, the insulation must be removed and the substrate must be inspected for corrosion.~~

For vessels that have the vessel shell maintain constant operation below 30°F or above 215 °F, condensation of moisture is absent when temperatures are maintained below 30 °F and above 215 °F. Examples of vessels that operate below 30 °F and above 215 °F include but are not limited to salt bath heaters, cryogenic vessels, etc. These vessels should not have inspection ports installed since this allows a place for moisture to collect under the insulation.

DTI Corrosion Manual Appendix 3.12 has been modified to address insulated vessels and the required inspections for insulated vessels. Insulated piping inspections are addressed in the Corrosion Manual Section 3.6.4.2, and references have been removed from Appendix 3.12

IV. Insulated ~~Pipe/~~Vessel Inspections

The exterior insulation of all insulated ~~pipe and~~ vessels shall be visually inspected at intervals stated ~~above~~in II. Inspection Intervals~~.~~ Inspection shall include determination~~s~~ of the condition of the exterior insulation and weather barrier. During atmospheric corrosion inspections of all vessels, subject to CFR Part 192, particular attention shall be paid to locations where bulging, swelling, and rust bleed is occurring in the insulation. If these are identified during the atmospheric corrosion inspection, the insulation must be removed and the substrate must be inspected for corrosion. If missing or damaged weather barrier, then the substrate must be inspected for corrosion and the weather barrier shall be repaired or replaced.

All vessels, subject to CFR Part 192, shall have exterior insulation removed for inspection if the entire vessel shell does not maintain constant operation below 30°F or above 215 °F, per manufacturer specifications. Insulation removal is not required since condensation of moisture is absent when temperatures are maintained below 30 °F and above 215 °F. Examples of vessels that operate below 30 °F and above 215 °F include but are not limited to cryogenic vessels, salt bath heaters, etc. These vessels should not have inspection ports installed since this allows a place for moisture to collect under the insulation.

The specific areas listed below should be nondestructively inspected at the intervals stated above. Specific areas that should be inspected on insulated ~~pipe or~~ vessels include:

A. All surfaces exposed to frequent hot/cold temperature cycling;

B. Horizontal ~~piping~~vessels, particularly at joints ~~or piping branches~~, and on the bottom ~~of the pipe~~;

C. Towers or other vessels at four inspection points around the tower/vessel with a 90 deg. separation and at two elevations near bottom and near top;

D. Wherever the insulation weather barrier has been mechanically damaged or removed such as the damaged insulation;

E. Wherever the insulation has changed shape or started to swell, indicating a possible rust buildup.

Plugs or windows should be cut in the insulation, exposing the steel for ultrasonic thickness testing. Information on NDT Inspection Plugs and location of plugs can be found in Appendix Section 3.09.01 NDT Inspection Plugs and Labels and Section 3.09 NDT Inspection Plug Locations. A baseline thickness measurement should be made at each inspection plug or window.

The most active corrosion sites are those where the steel passes through the insulation and on horizontal metal shapes (i.e., piers, ~~pipe~~ vessel supports~~holders~~, etc.)

~~The other major corrosion problem develops in situations where there are c~~Cycling temperatures that vary from below the dew point to above ambient temperature, as part of normal operations, allows condensation to develop on the vessel surface and possibly cause corrosion ~~on routine basis as a functionally of the piping system~~. Ambient temperature under insulation is considered at temperatures 30 °F to 215 °F. In this case,

the classic wet/dry cycle occurs when the cold metal develops water condensation that is then baked off during the hot/dry cycle. Cold/wet cycles can occur during ambient conditions on the ~~pipeline~~vessel. The ~~H~~hot/dry cycle ~~is~~occurs when the temperature is above 215 °F. - The transition from cold/wet to hot/dry includes an interim period of damp/warm conditions with accompanying high corrosion rates. - An example of a ~~piping~~vessel that ~~is associated with~~experiences hot/cold temperature cycling is regeneration ~~piping~~of natural gas dehydration towers. The ~~piping~~vessel may be at ambient temperature during normal operation, however, when a dehydration tower is undergoing regeneration, the temperature can exceed 215 °F for a few hours. Then the ~~piping~~vessel is cooled to ambient temperatures until the next regeneration cycle. Inspection ports shall be installed on the vessels subject to temperature cycling. ~~T~~to determine the coating condition or ~~possible~~to evaluate the vessel surface ~~corrosion~~ under the insulation ~~insulation that is subject to hot/cold cycles, inspection ports shall be installed on pipingthe vessel where corrosion may occur~~.

During atmospheric corrosion inspections, particular attention shall be paid to locations where bulging, ~~started to~~ swelling, and rust bleed is occurring in the insulation. Inspection shall include determination of the condition of the exterior insulation and weather barrier. ~~When~~If bulging and rust bleed ~~occurring~~are found during the inspection, the insulation shall be removed and the coating and ~~pipe~~vessel surface shall be inspected for corrosion. If missing or damaged weather barrier, then the substrate must be inspected for corrosion and the weather barrier shall be repaired or replaced. If corrosion has occurred, then ~~a corroded pipe evaluation (CorrEval) should be completed for corrosion greater than 20% wall loss~~it may be necessary to acquire a ~~bring in an Authorized~~Qualified Inspector to evaluate the corrosion and the vessel integrity. If the integrity of the ~~pipe~~vessel is acceptable, the area should be painted with an acceptable paint system and insulation should be re-installed. It is recommended to place inspection ports in locations where corrosion has previously occurred.

Whenever re-coating is needed under the insulation as it is removed or replaced, blast clean the old surface and apply the appropriate paint system as described in the Paint Design Guide.

For each item of concern, the proposed changes have been incorporated into the annual review processes for each document. Upon completion of the annual review process, the proposed changes will be communicated and reviewed with personnel prior to implementation. If you have any questions, or should require additional information, please do not hesitate to contact Kirk Wissmar at (304) 627-3369.

Respectfully,

Brian C. Sheppard

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