Cathodic Protection MCA's Rule Making 114

§192.453 General.

The corrosion control procedures required by §192.605(b)(2), including those for the design, installation, operation, and maintenance of cathodic protection systems, must be carried out by, or under the direction of, a person qualified in pipeline corrosion control methods. Not just OQ qualified but also a person qualified in pipeline corrosion control methods. Either through experience or training. Suggest you have a CP knowledgeable person in mind

§192.455 External corrosion control: Buried or submerged pipelines installed after July 31, 1971.

(a)Except as provided in paragraphs (b), (c), and (f) of this section, each buried or submerged pipeline installed after July 31, 1971, must be protected against external corrosion, including the following:

(1) It must have an external protective coating meeting the requirements of §192.461.

(2) It must have a cathodic protection within 1 year after completion of construction.

(f) This section does not apply to electrically isolated, metal alloy fittings in *plastic* pipelines, if:

(1) For the size fitting to be used, an operator can show by test, investigation, or experience in the area of application that adequate corrosion control is provided by the alloy composition; and

(2) The fitting is designed to prevent leakage caused by localized corrosion pitting.

(g) Electrically isolated metal alloy fittings installed after January 22, 2019, that do not meet the requirements of paragraph (f) must be cathodically protected, and must be maintained in accordance with the operator's *integrity management plan*.

Metfit Permasert

Metfit

Lyco

C&W tied to a bare unprotected main.
Pipe also suffered Third Party Damage-TPD
Length of time in which pipe was in service was not known. Could this be called ACTIVE Corrosion?

§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. Document, Document, Document, Operators have had to re-expose piping and perform the inspections.

REPORT OF MAIN AND SERVICE LINE INSPECTION

Form 1

COMPANY: Joes Natural Gas

This form is to be completed each time a transmission or distribution main or service line is uncovered for inspection or any other reason, such as making service connections, main extensions, replacements, etc.

DATE: 1-Jan-06

1. Location: Alley East of 5th , South of Main---30ft East of 5th, 125ft North of Main
2. Name of Inspection: Inspection of LK repair 001-06
3. Designation of Line: Transmission ______ Distribution X Service ______
4. Age of Pipe: 21 Years Line Size: 2.00 Inches
5. Maximum Operating Pressure: 35 PSIG
6. Pipe Specification: 2" C&W, grade B, .125wt
7. Cathodic Protection: by anode
8. Coating: Type FBE--(Fusion Bond Epoxy)
9. External Condition: Smooth ☒ Pitted ☐ Depth of Pits ______
10. Internal Condition: Smooth ☐ Pitted ☐ Depth of Pits ______
11. Other Structures in the Area Endangering Pipeline: None
12. Condition of Right-of-Way: Clear
13. Corrective Measures Taken if Needed: None-
14. Anodes Installed: How many? 1 Size 17 lb Location ______
15. Soil: Kind: Sand (☐) Clay (☐) Loam (☒) Cinders (☐) Refuse (☐)
    Packing: Loose (☐) Medium (☒) Hard (☐)
    Moisture Content: Dry (☐) Damp (☒) Wet (☐)

- **Notice any discrepancies?**

  Location of Dig

- **Other things to consider—P/S taken?**
- **Was internal inspection made? Pipe may not of been separated**

§192.461 External corrosion control: Protective coating.

(a) Each external protective coating, whether conductive or insulating, applied for the purpose of external corrosion control must-

(1) Be applied on a properly prepared surface; Do I wire brush surface or sand blast

(2) Have sufficient adhesion to the metal surface to effectively resist underfilm migration of moisture;

(3) Be sufficiently ductile to resist cracking;

(4) Have sufficient strength to resist damage due to handling and soil *stress*; and,

(5) Have properties compatible with any supplemental cathodic protection.

(b) Each external protective coating which is an electrically insulating type must also have low moisture absorption and high electrical resistance.

(c) Each external protective coating must be inspected just prior to lowering the *pipe* into the ditch and backfilling, and any damage detrimental to effective corrosion control must be repaired. By Jeeping or visual?

(d) Each external protective coating must be protected from damage resulting from adverse ditch conditions or damage from supporting blocks.

(e) If coated pipe is installed by boring, driving, or other similar method, precautions must be taken to minimize damage to the coating during installation.

Use of Powercrete coating a tougher FBE coating--expensive

§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.

(b) different anodic potential-

(1) The amphoteric metals must be electrically isolated from the remainder of the pipeline and cathodically protected; or

(2) The entire buried or submerged pipeline must be cathodically protected at a cathodic potential that meets the requirements of Appendix D of this part for amphoteric metals.

(c) The amount of cathodic protection must be controlled so as not to damage the protective coating or the pipe. -1200mv off on FBE—if higher can cause disbonding of the coating

§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.

- What is your criteria?
- -.850—most widely used criteria, easiest to use.
- 300 mv shift—used mainly on bare/anode
- 100mv polarization—Time consuming-costly to determine native P/S.
- E-log-I –Not used by operators

§192.465 External corrosion control: Monitoring Effective 5-24-2023

(b) (1) Each cathodic protection rectifier or impressed current power source must be inspected six times each calendar year, but with intervals not exceeding 2 ½ months between inspections, to ensure adequate amperage and voltage levels (Not using the gauges) needed to provide cathodic protection are maintained. This may be done either through remote measurement or through an onsite inspection of the rectifier.

§192.465 External corrosion control: Monitoring.

(b)(2) **After January 1, 2022, each remotely inspected rectifier must be physically inspected for continued safe and reliable operation at least once each calendar year, but with intervals not exceeding 15 months.**

§192.465 External corrosion control: Monitoring. Effective 5-24-2023

(c) Each reverse current switch, each diode, and each interference bond whose failure would jeopardize structure protection must be electrically checked for proper performance six times each calendar year, but with intervals not exceeding 2 1/2 months. Each other interference bond must be checked at least once each calendar year, but with intervals not exceeding 15 months.

(d) Each *operator* must promptly correct any deficiencies indicated by the inspection and testing required by paragraphs (a) through (c) of this section. For onshore gas transmission pipelines, each operator must develop a remedial action plan and apply for any necessary permits within 6 months of completing the inspection or testing that identified the deficiency. Remedial action must be completed promptly, but no later than the earliest of the following: prior to the next inspection or test interval required by this section; within 1 year, not to exceed 15 months, of the inspection or test that identified the deficiency; or as soon as practicable, not to exceed 6 months, after obtaining any necessary permits.

The 2nd part of (d) applies to transmission, there is some PHMSA enforcement guidance basically saying the same for all type of operations.

§192.465 External corrosion control: Monitoring. Effective 5-24-2023

(f) An operator must determine the extent of the area with inadequate cathodic protection for onshore gas transmission pipelines where any annual test station reading (pipe-to-soil potential measurement) indicates cathodic protection levels below the required levels in appendix D to this part.

1) Gas transmission pipeline operators must investigate and mitigate any non-systemic or location-specific causes.

(2) To address systemic causes, an operator must conduct close interval surveys in both directions from the test station with a low cathodic protection reading at a maximum interval of approximately 5 feet or less. An operator must conduct close interval surveys unless it is impractical based upon geographical, technical, or safety reasons. An operator must complete close interval surveys required by this section with the protective current interrupted unless it is impractical to do so for technical or safety reasons. An operator must remediate areas with insufficient cathodic protection levels, or areas where protective current is found to be leaving the pipeline, in accordance with paragraph (d) of this section. An operator must confirm the restoration of adequate cathodic protection following the implementation of remedial actions undertaken to mitigate systemic causes of external corrosion.

Casings

- What potential differences are you looking for on Casing/Soil (C/S)?
- 50mv, 100mv, 200 mv, essential the same—if essential the same, define essential the same? Most operators use 100mv
- What steps do you take, in the event you may have a shorted casing? Panhandle Eastern tests---Do you expose casing and try to correct short or go straight to monitoring? How often do you monitor?

Shorted casings

- PHMSA is pushing to fix
- Dig and clear
- Pump the casing with High Dielectric fill or corrosion inhibiting materials
- Monitor with ILI tools
- If we go to leak survey and have a leak—not a good deal
- Call Bruce's brother in law and have him come out and bore in new pipe—eliminating the casing

§192.469 External corrosion control: Test stations.

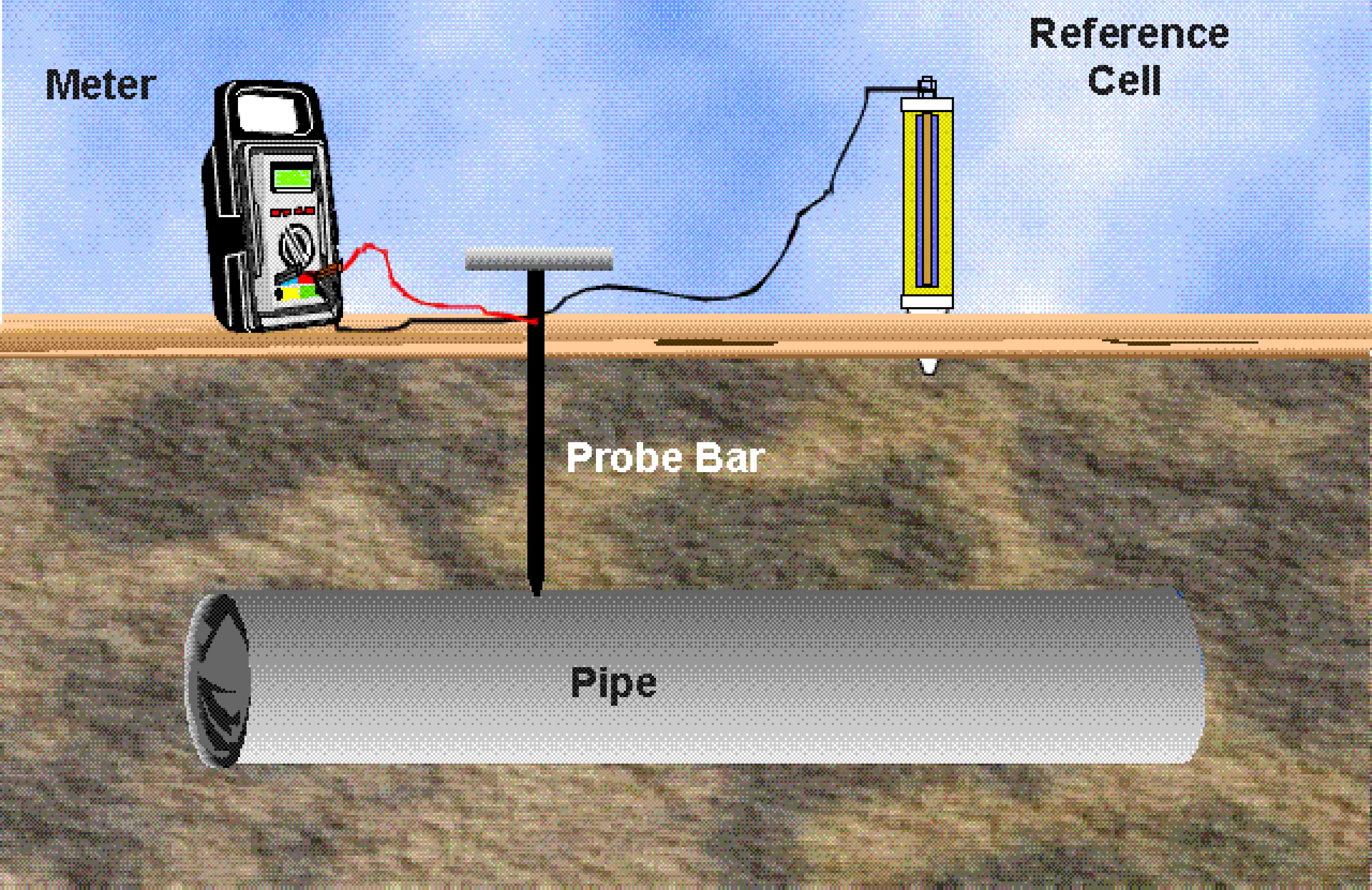
Each pipeline under cathodic protection required by this subpart must have sufficient test stations or other contact points for electrical measurement to determine the adequacy of cathodic protection. Every mile on rectifier pipe—more often on anode pipe—sufficient test stations

Do you use test leads or pipe structures? If pipe structure is available use it.

There have been questions asked when an operator uses test leads when there is a metallic contact present. In other words why do we use a test lead when pipe is present.

Be careful when using curb boxes. It's questionable when the wire in a curb box reads –1.70 on asphalt coated pipe. The max potential of a mag anode is about –1.70.---- Operators have been asked to tie on to the test lead with a locator to insure the test lead is tied to the pipe.

Is a Holiday (hole in coating) created?



§192.471 External corrosion control: Test leads.

- (a) Each test lead wire must be connected to the pipeline so as to remain mechanically secure and electrically conductive.
- (b) Each test lead wire must be attached to the pipeline so as to minimize stress concentration on the pipe.
- (c) Each bared test lead wire and bared metallic area at point of connection to the pipeline must be coated with an electrical insulating material compatible with the pipe coating and the insulation on the wire.—If the directions on a bucket of Mastic or other material instructs you to wait 2 hours before back filling-then wait 2 hours.

§192.473 External corrosion control: Interference currents.

(a) Each operator whose pipeline system is subjected to stray currents shall have in effect a continuing program to minimize the detrimental effects of such currents.

(b) Each impressed current type cathodic protection system or galvanic anode system must be designed and installed so as to minimize any adverse effects on existing adjacent underground metallic structures. What are your procedures on new or replaced groundbed installations to insure you do not effect other underground metallic structures? Do you have procedures?

- A lot of operators use a 200 foot circumference and take potentials on other metallic structures before and after energizing the rectifier.

§192.473 External corrosion control: Interference currents.
Effective May 24, 2023

(c) For onshore gas transmission pipelines, the program required by paragraph (a) of this section must include:

(1) Interference surveys for a pipeline system to detect the presence and level of any electrical stray current. Interference surveys must be conducted when potential monitoring indicates a significant increase in stray current, or when new potential stray current sources are introduced, such as through co-located pipelines, structures, or high voltage alternating current (HVAC) power lines, including from additional generation, a voltage up-rating, additional lines, new or enlarged power substations, or new pipelines or other structures;

(2) Analysis of the results of the survey to determine the cause of the interference and whether the level could cause significant corrosion, impede safe operation, or adversely affect the environment or public;

(3) Development of a remedial action plan to correct any instances where interference current is greater than or equal to 100 amps per meter squared or if it impedes the safe operation of a pipeline, or if it may cause a condition that would adversely impact the environment or the public; and

(4) Application for any necessary permits within 6 months of completing the interference survey that identified the deficiency. An operator must complete remedial actions promptly, but no later than the earliest of the following: within 15 months after completing the interference survey that identified the deficiency; or as soon as practicable, but not to exceed 6 months, after obtaining any necessary permits.

§192.473 External corrosion control: Interference currents.

This was discussed at the seminar—It can be a problem when piping is in the vicinity of wind generators or solar collectors.

What kind of AC voltage are you looking for—Had a company whose procedure said 10 volts ac—they had to do a repair and the pipe only had 9 volts ac.

NACE SP0177-2007(it is not IBR) says 15 volts ac

Thinking OSHA is 15 volts ac

This will take someone with Corrosion experience

§192.475 Internal corrosion control: General.

(a) Corrosive gas may not be transported by pipeline, unless the corrosive effect of the gas on the pipeline has been investigated and steps have been taken to minimize internal corrosion. If coming off of a gathering system- do we ask for a gas analysis. Hydrocarbon permeation of plastic

(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- Document—If it is not documented—it was not done. Coupons from Hot taps- as well as the cut outs when tying in the new pipe.

(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.

(c) Gas containing more than 0.25 grain of hydrogen sulfide per 100 standard cubic feet (5.8 milligrams/m3) at standard conditions (4 parts per million) may not be stored in pipe-type or bottle-type holders.


1F
11
12
13
14

§192.477 Internal corrosion control: Monitoring.

- If corrosive gas is being transported, coupons or other suitable means must be used to determine the effectiveness of the steps taken to minimize internal corrosion. Each coupon or other means of monitoring internal corrosion must be checked two times each calendar year, but with interval not exceeding 7 1/2 months. Normally does not apply to distribution. If it does, Where are your coupons?

  Are they located in the low points or the high points of your system.

§192.479 Atmospheric corrosion control; General.

(a) Each operator must clean and coat each pipeline or portion of pipeline that is exposed to the atmosphere, except pipelines under paragraph (c) of this section.

(b) Coating material must be suitable for the prevention of atmospheric corrosion.

(c) Except portions of pipelines in offshore splash zones or soil-to-air interfaces, the operator need not protect from atmospheric corrosion any pipeline for which the operator demonstrates by test, investigation, or experience appropriate to the environment of the pipeline that corrosion will—

(1) Only be a light surface oxide; or

(2) Not affect the safe operation of the pipeline before the next scheduled inspection.

§192.481 Atmospheric corrosion control: Monitoring.

(a) Each operator must inspect each pipeline or portion of pipeline that is exposed to the atmosphere for evidence of atmospheric corrosion, as follows:

If the pipeline is located:	Then the frequency of inspection is:
Onshore other than a service line	At least once every 3 calendar years, but with intervals not exceeding 39 months
Onshore service line	At least once every 5 calendar years, but with intervals not exceeding 63 months, except as provided in paragraph (d) of this section.
Offshore	At least once each calendar year, but with intervals not exceeding 15 months

§192.481 Atmospheric corrosion control: Monitoring.

c) During inspections the operator must give particular attention to pipe at soil-to-air interfaces, under thermal insulation, under disbonded coatings, at pipe supports, in splash zones, at deck penetrations, and in spans over water.

d) If atmospheric corrosion is found on a service line during the most recent inspection, then the next inspection of that pipeline or portion of pipeline must be within 3 calendar years, but with intervals not exceeding 39 months.

Operator did not know he was to inspect under the coating.

Operators can be assisted in getting pipe replaced.


2002 9 27

Picture is rotated, picture taken upside down.

§192.483 Remedial measures: General.

- (a) Each segment of metallic pipe that replaces pipe removed from a buried or submerged pipeline because of external corrosion must have a properly prepared surface and must be provided with an external protective coating that meets the requirements of Sec. 192.461.
- (b) Each segment of metallic pipe that replaces pipe removed from a buried or submerged pipeline because of external corrosion must be cathodically protected in accordance with this subpart.
- (c) Except for cast iron or ductile iron pipe, each segment of buried or submerged pipe that is required to be repaired because of external corrosion must be cathodically protected in accordance with this subpart.

§192.485 Remedial measures: Transmission Lines effective 5-24-2023

(a) General corrosion. Each segment of *transmission line* with general corrosion and with a remaining wall *thickness* less than that required for the *MAOP* of the *pipeline* must be replaced or the operating *pressure* reduced commensurate with the strength of the *pipe* based on actual remaining wall thickness. However, corroded pipe may be repaired by a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe. Corrosion pitting so closely grouped as to affect the overall strength of the pipe is considered general corrosion for the purpose of this paragraph.

(b) Localized corrosion pitting. Each segment of transmission line pipe with localized corrosion pitting to a degree where leakage might result must be replaced or repaired, or the operating pressure must be reduced commensurate with the strength of the pipe, based on the actual remaining wall thickness in the pits

(c) Calculating remaining strength. Under paragraphs (a) and (b) of this section, the strength of pipe based on actual remaining wall thickness must be determined and documented in accordance with § 192.712

§192.487 Remedial measures: Distribution lines other than cast iron or ductile iron lines.

(a) General corrosion. Except for cast iron or ductile iron pipe, each segment of generally corroded distribution line pipe with a remaining wall thickness less than that required for the MAOP of the pipeline, or a remaining wall thickness less than 30 percent of the nominal wall thickness, must be replaced. However, corroded pipe may be repaired by a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe. Corrosion pitting so closely grouped as to affect the overall strength of the pipe is considered general corrosion for the purpose of this paragraph. Asphalt coated pipe is bad about trapping water and corroding under coating at Meter risers & regulator stations.

(b) Localized corrosion pitting. Except for cast iron or ductile iron pipe, each segment of distribution line pipe with localized corrosion pitting to a degree where leakage might result must be replaced or repaired.

§192.491 Corrosion control records.

(a) Each operator shall maintain records or maps to show the location of cathodically protected piping, cathodic protection facilities, galvanic anodes, and neighboring structures bonded to the cathodic protection system. Records or maps showing a stated number of anodes, installed in a stated manner or spacing, need not show specific distances to each buried anode.

(b) Each record or map required by paragraph (a) of this section must be retained for as long as the pipeline remains in service.

(c) Each operator shall maintain a record of each test, survey, or inspection required by this subpart in sufficient detail to demonstrate the adequacy of corrosion control measures or that a corrosive condition does not exist. These records must be retained for at least 5 years, except that records related to §§192.465(a) and (e) and 192.475(b) must be retained for as long as the pipeline remains in service. .465 A & E are P/S reads and areas of active corrosion, .475 B is Internal corrosion inspections.

Things to remember

- If it is not documented– it was not done.

- If your have any questions on how and when to perform a DOT inspection, consult your O&M and/or your supervisor.

192.710 Transmission lines: Assessments outside of high consequence areas
MCA's

(a) *Applicability*: This section applies to onshore *steel* transmission *pipeline* segments with a maximum allowable operating *pressure* of greater than or equal to 30% of the specified minimum *yield strength* and are located in:

(1) A Class 3 or Class 4 location; or

(2) A *moderate consequence area* as defined in §192.3, if the pipeline segment can accommodate inspection by means of an instrumented inline inspection tool (*i.e.*, "smart pig").

(3) This section does not apply to a pipeline segment located in a *high consequence area* as defined in §192.903.

(b) *General* -

(1) *Initial assessment*. An *operator* must perform initial assessments in accordance with this section based on a risk-based prioritization schedule and complete initial assessment for all applicable pipeline segments no later than July 3, 2034, or as soon as practicable but not to exceed 10 years after the pipeline segment first meets the conditions of §192.710(a) (e.g., due to a change in class location or the area becomes a moderate consequence area), whichever is later.

Moderate consequence area means:

(1) An onshore area that is within a potential impact circle, as defined in §192.903 containing either:

- (i) Five or more buildings intended for human occupancy; or
- (ii) Any portion of the paved surface, including shoulders, of a designated interstate, other freeway, or expressway, as well as any other principal arterial roadway with 4 or more lanes, as defined in the Federal Highway Administration's Highway Functional Classification Concepts, Criteria and Procedures, Section 3.1 (see: *https://www.fhwa.dot.gov/planning/processes/statewide/related/highway_functional_classifications/fcauab.pdf*), and that does not meet the definition of high consequence area, as defined in §192.903.

(2)The length of the moderate consequence area extends axially along the length of the pipeline from the outermost edge of the first potential impact circle containing either 5 or more buildings intended for human occupancy; or any portion of the paved surface, including shoulders, of any designated interstate, freeway, or expressway, as well as any other principal arterial roadway with 4 or more lanes, to the outermost edge of the last contiguous potential impact circle that contains either 5 or more buildings intended for human occupancy, or any portion of the paved surface, including shoulders, of any designated interstate, freeway, or expressway, as well as any other principal arterial roadway with 4 or more lanes.

114 Inspections
Reduction of emissions

Have approximately 50 left to do—you will be inspected in 2023. You should have procedures in place. They were due December 27, 2021

Commission Rule Making

Rule making is/has been made for excavation damage.

Encourage all to sign up GovDelivery at Our website [OCC Website]

https://oklahoma.gov/occ/public-meetings.html ers

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QUESTIONS