Job Description

Job Name: ______________________________

PO Number: ______________________________

Job Description: ______________________________

____

____

____

Start Date: ______________________________

Completion Date: ______________________________

Replace this sheet with a simple map of the project

WTG

New Construction Checklist - Steel

Once task is completed check box

Tab 1 ☐ Notes Page
-Daily Notes

Tab 2 ☐ Inspector Resume
-Keep record of resume/qualifications

Tab 3 ☐ Daily Welding Inspections
-Weld Inspections P-192.241

Tab 4 ☐ Daily Coating Inspections
-Apply and Repair External Coating P-192.461

Tab 5 ☐ Daily Installation Inspections
-Installation of Pipe in a Ditch P-192.319

Tab 6 ☐ Project Maps, State Permits, County Permits, ETC
- Keep record of submittal and approvals

Tab 7 ☐ Fill-out and submit RRC New construction Form PS-48 if required
-Keep record of submital and approval

Tab 8 ☐ Ensure project is covered by digtess grids. See 4.3.2 of Texas Damage Prevention Plan
- if not covered, send mapping department a proposed route prior to start of construction

Tab 9 ☐ Bids and Signed Contract

Tab 10 ☐ Run a report of contractors EWN qualifications prior to start of project
- Records should include all personnel involved with covered tasks

Tab 11 ☐ Contractor given the O&M Procedures to have on sight
- Contractor is required to follow O&M Procedures
- Document on signature page within Tab 6

Tab 12 ☐ Pipe Delivery Inspections and MTR's. P-192.305 General Inspection
- Inspect delivered pipe and fill out form
- Collect MTR's, Invoices, Pictures, etc

Tab 13 ☐ Component Delivery Inspections and MTR's. P-192.305 General Inspection
- Inspect delivered pipe and fill out form
- Collect MTR's, Invoices, Pictures, etc

Tab 14 ☐ Record the handling and storage of pipe used for project
- ensure compliance with 192.69 and document on WTG 1400

Tab 15 ☐ Verify that all casing, fittings and valves comply with P192.105
- keep records of any supporting documentation. MTR's, etc

Tab 16 ☐ Verify that the design of pipe line is protected against accidental over pressuring (P-192.105)
-Regulators and Reliefs added: Document on WTG 1102 and maintain in Compliance Records

Tab 17 ☐ Fill out and keep F192.619 - MAOP Determination

Tab 18 ☐ Pressure test pipelines in accordance with P192.501
- Document of Form F-192.517 or equivalent and keep pertinant records

Tab 19	☐	Complete Above Ground Indirect Assessment of Transmission Lines - P-192.319
Tab 20	☐	Purge pipeline in accordance with P-192.629 - Scheduled emissions (purging): Fill out report and submit to Compliance Department prior to purge
Tab 21	☐	Start up of pipeline: Ensure compliance with P-192.605(b)(5)
Tab 22	☐	Facility Abandonments: Document on appropriate form (F192.727 or WTG 1400) - ensure compliance with P-192.727
Tab 23	☐	Complete and submit Project Report WTG 1400 to Mapping Department
Tab 24	☐	Welding Procedures - P-192.225
Tab 25	☐	Welders Certificates - P-192.225
Tab 26	☐	X-Ray Certificates - P-192.243
Tab 27	☐	Cathodic Protection - P-192.455
Tab 28	☐	Photos
Tab 29	☐	Miscellaneous - Any additional items not included above

Tab 1

Notes:

TAB 2

- **If WTG opts to use a 3rd party inspector/inspectors, the resumes of all inspectors that are onsite will need to be gathered and kept in this tab.**
- **If WTG is utilizing our personnel to inspect the project, ensure that the personnel are OQ Qualified in the respective tasks that they are inspecting. Keep a record of all WTG employees that served as inspectors on the project on page 2 of Tab 1.**
- **Responsible Party: Manager, WTG Inspector or 3rd Party Inspector**

Tab 2

WTG Personnel:

Name:_____________________________________ Date:____________________

Name:_____________________________________ Date:____________________

Name:_____________________________________ Date:____________________

Name:_____________________________________ Date:____________________

Name:_____________________________________ Date:____________________

Name:_____________________________________ Date:____________________

Name:_____________________________________ Date:____________________

Name:_____________________________________ Date:____________________

Name:_____________________________________ Date:____________________

Name:_____________________________________ Date:____________________

Tab 3

- **Document visual inspections of welds using Form "Pipeline Daily Report" and keep documentation in this tab**
- **Complies with Procedure 192.241 Visual Inspection of Welds**
- **Responsible Party: WTG Inspector or 3rd Party Inspector**

g) Do not allow heating of the pipe to obtain proper alignment for welding.

h) Hammering of the pipe to attain alignment is not permitted.

3. Monitor welding equipment and welding operations.

a) Make the electrical ground contact point of a material grade not greater than that of the line pipe material. Securely attach the ground to the bevel or an existing weld in such manner to prevent arc bums. Make the contact area large enough to prevent local overheating or arcing between the contact. There can be no magnetic ground clamps or magnets of any kind on the pipe during welding.

b) Use insulated electrode holders on fabrication, repairs, or tie-ins. There can be no arc strikes or dragging of electrodes on the surface of the work. Confine striking of arcs within the welding groove. Treat any arc bum on a finished weld that results in pitting or loss of weld metal in the same manner as an arc strike outside the welding groove.

c) Ensure that the maximum time lapse between weld passes as outlined on the welding procedure specification is being followed. Exception: Complete tie-in welds and live-line welding without interruption once welding is started.

d) Ensure that specific preheating requirements and temperatures as outlined in the approved welding procedure specification are being used. Other conditions may exist where preheating is required. Preheat using a propane torch or other approved method. Do not use oil burners - they are not permitted. Check preheating temperatures just prior to the start of welding by using temperature-indicating crayons, thermocouple pyrometers, or by other approved methods. Make sure the preheated area extends at least 3" on each side of the weld preparation and is uniform around the pipe circumference. Do not permit the temperature in the weld area to fall below the required preheat temperature at any time during the welding process. If welding is interrupted for any reason make sure the weld is preheated to the proper temperature before welding is resumed.

e) Ensure that slag and remaining flux is removed from each weld pass by hand power tools prior to deposition of additional weld metal. Ensure visible defects such as slag cavities, cold laps, surface porosity, starts, stops, and high points are removed by grinding. Make sure that no two adjacent or successive weld beads are started or stopped at the same location.

f) Backwelding shall not be permitted as a routine welding practice. Determine whether to allow back welding for fabricated assemblies and pipeline weld repairs. Approve suitable back-welding prior to use.

g) Make sure that used welding rods are placed in an appropriate bucket and not discarded on the ground.

4. Visually inspect completed welds

a) Inspect before, during, and after welding operations. Ensure that the completed weld is brushed and thoroughly cleaned before the weld is visually inspected. Make sure the completed weld has a uniform appearance around the entire pipe circumference and that the weld surface and surrounding area is free of weld spatter.

b) Ensure that each weld meets standards of acceptability prescribed in API 1104 (latest DOT-approved edition), unless otherwise specified in the job specifications, contract or drawings. The welding inspector shall be responsible for the final decision on weld acceptability.

c) Make sure the nondestructive testing requirements (see Procedure P-192.243) are met.

d) Order the repair or replacement of each weld or portion thereof that does not meet the visual and/or nondestructive acceptability requirements of the applicable code in accordance with procedure P-192.245 Repair and Removal of Weld Defects. The repair shall meet the same acceptance requirements as the original weld.

e) Document the completed weld on Form F-192.225.

Pipeline Daily Report

WTG		Job #:		Report #	
Client:	WEST TEXAS GAS				
Project:					
Name:		Title:		Location:	
1. Subject				Contractor:	

2. Report Entries

	COUNT#		STA#		STA#	FT. TODAY	TO DATE	% COMPLETE
Row Chipped				TO				
Row Graded				TO				
Row Ditched				TO				
Row Strung				TO				
Coating				TO				
Pipe Gang				TO				
Firing Line				TO				
Lower-In				TO				
Backfill				TO				
HDD				TO				
Clean-Up (Final)				TO				
Tested				TO				

Comments

Test Leads:	
Tie-ins:	
Rock Shield	
Bends:	
Sand Bags:	
WELDING PROCEDURE SPECIFICATION:	

# Welds Made Today		# Welds Made To Date			# Repairs Today		# Repairs To Date	

#Welds X-Rayed Today:		X-Rayed To Date:		Repairs % X-Rayed:	

Low	High	Weather:		Signature:	
		Rainfall (inches):		Date:	

Tab 4

- **Document coating inspections using Form "WTG Daily Coating Inspections" and keep documentation in this tab**
- **Complies with Procedure 192.461 Apply and Repair External Coating**
- **Responsible Party: WTG Inspector or 3rd Party Inspector**

Description	This procedure gives the steps required to apply and repair external coating.
Regulatory Applicability	All DOT pipelines that are constructed, relocated, modified, replaced, including short segments replaced, will be coated. Pipelines that are converted to Part 192 service under 192.14 will be coated if relocated, replaced or substantially altered. ☒ Regulated Transmission Pipelines ☒ Regulated Gathering Pipelines (Type A) ☒ Regulated Gathering Pipelines (Type B) ☒ Regulated Distribution Pipelines
Frequency	As needed when a new pipeline is constructed or an existing pipeline is relocated, replaced or otherwise changed. This procedure may also be used after the pipeline coating has been damaged or a piece of pipe has been replaced. This should be done just prior to lowering the pipe into the ditch or submerging the pipe.
Reference	49 CFR 192.461 *External Corrosion Control: Protective Coating* LA Title 43 Part XIII 2113 *External Corrosion Control: Protective Coating*
Forms / Record Retention	Document coating type with pipeline specifications
Related Specifications	None

OQ Covered Task

0991 Coating Application and Repair: Brushed or Rolled
1001 Coating Application and Repair: Sprayed
1011 External Coating Application and Repair – Wrapped
1021 Apply or Repair Internal Coating Other Than by Brushing, Rolling or Spraying

(In order to perform the tasks listed above; personnel must be qualified in accordance with West Texas Gas's Operator Qualification program or directly supervised by a qualified individual.)

Procedure Steps

Steel pipe that is to be buried must be coated to protect against corrosion. Weld joints, damaged areas, short sections of pipe, and buried fittings will have to be coated in the field.

1. Identify section to be coated.
2. Identify existing coating type, if previously coated.
3. Determine type of coating to be applied. Coating must:
   a) Be designed to mitigate corrosion of the buried or submerged pipe and components;
   b) Have sufficient adhesion to the metal surface to prevent under film migration of moisture;
   c) Be sufficiently ductile to resist cracking;
   d) Have enough strength to resist damage due handling and soil stress;
   e) Support any supplemental cathodic protection; and
   f) If the coating is an insulating type, have low moisture absorption and provide high electrical resistance.
   g) Must be inspected just prior to lowering the pipe into the ditch and backfilling. Any damage detrimental to effective corrosion control must be repaired.
4. Obtain the necessary tools, materials, and safety equipment.
5. If pipeline was previously coated, remove damaged coating on existing pipe.
6. Prepare surface for coating application according to coating manufacturer's specification.
7. Examine the pipe for evidence of corrosion, pitting, gouges, dents or other surface damage prior to applying coating.
8. Does the pipe surface have any of these damages that require further investigation?
   a) No: Continue with Step #9
   b) Yes: Seek assistance from appropriate personnel for additional investigation and corrective actions before applying coating.
9. Apply coating according to vendor/manufacturer specifications.
10. When applying the wrap:
    a) Pipe wrap tape and primer must be from the same manufacturer and approved for use with each other. Coating wrap should be minimum thickness of 35 mils.
    b) The wrap must have sufficient adhesion to the material surface to effectively resist under film migration of moisture. It must be sufficiently ductile to resist cracking and have sufficient strength to resist damage due to handling and soil stress.
    c) Coat the exposed steel with sufficient primer making sure to leave no voids in coverage. Primer must extend beyond tape one inch.

d) Let dry until tacky.

e) Tape wrap should extend no less than six inches onto existing coating on either side of weld area, repair, or replacement.

f) Wrap uphill, 50% overlap with no wrinkles.

Fusion Bond Epoxy Coatings:

Fusion Bond Epoxy coatings may be used for field joints, tie-ins, below ground fabrications, bore joint coating, and rehabilitation of existing pipelines. These products may be applied manually using brushes, rollers or by spraying using approved equipment. Strict manufacturer's instructions shall be followed pertaining to cleaning of materials to be coated, mixing and application of the product, regulating and inspecting the thickness of the application, and cure times due to changing conditions. Project inspectors will make sure that all equipment used in this process meets manufacturer's guidelines and all contract personnel and company personnel have the proper equipment and training to check material thickness either before curing (wet test) or after the material is cured (dry test).

Petrolatum Tape Installation:

Installation of petrolatum products should be limited to odd shaped buried pipeline components such as valves, flanges, service tee connections, and other applications that could be subject to voids in the coverage that would allow water or other impurities to collect on the pipe or component surface. When using these products strict attention shall be paid to manufacturer's instructions.

Roskoat/Mastic Coatings:

Roskoat/Mastic type coatings may be used for coating on exposed pipelines where repairs have been made to existing facilities. This type of coating should never be used on new construction, or on typical girth welds, and should be reserved for applications where wrapping the piping or components is not an option. All piping to be coated should be cleaned to bare metal with scrapers and power tools until all soil, rust, scale, and oil are removed. Care should be taken that all surfaces are coated with an even layer of material and allowed to dry and cure before backfilling.

Roskoat/Mastic coatings can be very damaging to plastic products and should never be allowed to accidently come into contact with plastic piping as it can cause failures.

Coating Testing

All lengths of pipe shall be inspected for holidays in the coating prior to installation in the field as the pipe is lowered into the ditch. This may be accomplished by jeeping the pipe at the job site.

1. Equipment

   Coating inspection shall be made with an approved (pulse type) holiday detector (jeep) having a voltage range of 1,000 - 14,000 volts.

2. Inspection Voltage

   Required test voltages for various fusion-bonded coating thicknesses and for coal tar coating are as illustrated in the table below.

   a) Improper high voltage may damage the pipe coating.

   b) Improper low voltage settings will not provide valid testing.

Required Test Voltages For FUSION-BONDED Coating Thicknesses			
Coating Thickness (Mils)	**Test Voltage**	**Coating Thickness (Mils)**	**Test Voltage**
10	1,600	15	2,000
11	1,800	16	2,000
12	1,800	20	2,250
13	1,800	25	2,500
14	2,000	30	3,000
Required Test Voltage For COAL TAR Coating			
93.75	12,000	-	-

3. Equipment Check
   a) Test the energy source (battery) for proper voltage output. Refer to manufacturer's instructions.
   b) Connect the exploring electrode and grounding cable to the terminal of the detectors.
   c) Switch the detector to the “On” position.
   d) Touch the exploring electrode to the ground cable alligator clip. The instrument signal should actuate in accordance with the instrument manufacturer's operating instructions.
   e) If the instrument signal actuates, the instrument is ready to be calibrated. If it does not actuate, consider it defective and contact the manufacturer for repair.
   f) Full-circle wire-type spring electrodes shall be used for testing pipe sizes 3 inch and larger.
   g) Full-circle or half-circle wire-type spring electrodes may be used on 2-inch diameter pipe.
   h) Brush-type electrodes made of conductive rubber or half-circle spring electrodes shall be used for testing pipe 1 inch and 1 1/4 inch in diameter.
4. Equipment Calibration
   a) The detector shall be calibrated to the specified voltage to be used before each initial daily use. It shall be recalibrated periodically during the day.
   b) Connect a high-voltage voltmeter between the probe and ground lead.
   c) Switch the detector to the “On” position.
   d) Compare the voltage of the voltmeter with the output voltage of the detector.

e) Switch the detector to the "Off" position and adjust to the specified voltage, if necessary.

CAUTION: Detector shall be in the "Off" position before making any changes in the voltage setting or connecting or disconnecting the voltmeter leads.

f) Switch the detector to the "On" position.

g) Again, compare the voltage of the voltmeter with the output voltage of the detector.

h) Switch the detector to the "Off" position and disconnect the voltmeter.

i) The instrument is now ready for use.

5. Testing Procedure

a) The pipe to be inspected shall be grounded from the bare end of the pipe to the earth. When individual joints of pipe are being tested, each joint shall be individually grounded.

b) If moisture exists on the coating surface, it shall either be removed or the surface shall be allowed to dry prior to conducting the test. Moisture on the coating surface can cause erroneous indications.

c) Make contact with the detector electrode on the bare pipe end to verify that the instrument is properly grounded. This test shall be done each time a new section of coated piping is tested.

d) For applications requiring a spring-type electrode, use a single pass, moving the electrode over the surface of the dry coating at a rate of approximately 1 foot per second.

e) For applications requiring a brush-type or half-circle electrode, a pass on each side of the pipe 180^0 apart is required.

f) As defects are identified, mark the location so repairs can be made upon completion of jeeping and prior to installation.

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WTG Daily Coating Inspection
Date:
Project:
Inspector:
Signature:

Abrasive Blasting			
Type/Grade of Abrasive:			
Specified Standard:			
	Anchor Profile Measurement (Mils)	**Comments**	**Attach Tapes**
1			
2			
3			

Coatings		
Type of Coating:		
Application Method:		
Specified Standard:		
	Wet Film Thickness Measurement (Mils)	**Comments**
1		
2		
3		

Tab 5

- **Document installation inspections using Form “WTG Pipe Installation Inspection” and keep documentation in this tab**
- **Complies with Procedure 192.319 Installation of Pipe in a Ditch**
- **Responsible Party: WTG Inspector or 3rd Party Inspector**

Description	This procedure provides guidance for excavation, installation and backfilling to prevent damage to all pipelines including service lines.
Regulatory Applicability	☒ Regulated Transmission Pipelines ☒ Regulated Gathering Pipelines ☒ Regulated Distribution Pipelines
Frequency	As needed

Reference

49 CFR 192.319	*Installation of Pipe in a Ditch*
49 CFR 192.321	*Installation of Plastic Pipe*
49 CFR 192.325	*Underground Clearance*
49 CFR 192.327	*Cover*
49 CFR 192.329	*Installation of plastic pipelines by trenchless excavation*
49 CFR 192.361	*Service Lines: Installation*
49 CFR 192.363	*Service Lines: Valve Requirements*
49 CFR 192.365	*Service Lines: Location of Valves*
49 CFR 192.367	*Service Lines: General Requirements for Connections to Main Piping*
49 CFR 192.371	*Service Lines: Steel*
49 CFR 192.375	*Service Lines: Plastic*
49 CFR 192.379	*New Service Lines Not in Use*
49 CFR 192.381	*Service Lines: Excess Flow Valve Performance Standards* WTG P.192.605(b)(9) *Trench Safety*
WTG P-192.243	*Non-Destructive Testing of Welds*
WTG P-192.501	*Steel Pipeline Pressure Test Requirements*
WTG P-192.513	*Plastic Pipe Pressure Test Requirements*
OSHA 1926.651(c)(2)	*Specific Excavation Requirements*

Forms / Record Retention	WTG-1400 Project Report / Life of Pipeline

Related Specifications

None

OQ Covered Task

0301	*Manually Open & Close Valves*
0311	*Adjust & Monitor Flow or Pressure / Manual Valve Operation*
0641	*Visually Inspect Pipe & Components Prior to Installation*
0811	*Visually Inspections of Welding & Welds*
0861	*Installation of Steel Pipe in a Ditch*
0871	*Installation of Steel Pipe in a Bore*
0901	*Installation of Plastic Pipe in a Ditch*
0911	Installation of Plastic Pipe in a Bore
0941	*Installation of Tracer Wire*
0951	*Installation of Above Grade Pipe*
0971	*Installation and Maintenance of Casings, Spacers, Vents & Seals*
0981	*Backfilling*
1341	*Provide Or Assure Adequate Pipeline Support During Operator Initiated Excavation Activities*

(In order to perform the tasks listed above, personnel must be qualified in accordance with West Texas Gas's Operator Qualification program or directly supervised by a qualified individual.)

Procedure Steps

NOTE: Lowering or relocating a main or lateral of a piping system under pressure will not be permitted unless a written plan is submitted and approved by senior management.

Prior to Excavating

1. Refer to your state specific Damage Prevention Plan located at www.westtexasgas.com for WTG approved procedures regarding excavation and damage prevention.
2. Refer to (P-192.605(b)(9) Trench Safety and P-192.69 Storage and Handling of Pipe
3. Ensure pipe is placed on padded blocks, wedges, etc to prevent movement during the fitting and welding process.
4. Inspect all equipment to be used such as side booms, track hoes, backhoes, rollers, calipers, lifting devices, etc for any defects that could harm the pipe.
5. Ensure that the trench is stable and can withstand vibration from heavy machinery.
6. If pipeline will encroach any underground facility, P-192.325 must be reviewed.

Installation of Plastic Pipe

1. Prior to beginning work in the trench and on a periodic basis while work is being performed, test the air in the trench with a certified CGI for concentrations of a combustible gaseous atmosphere which could cause an oxygen deficient atmosphere.
2. Visually inspect ditch.
   a) Make sure the ditch is free of rocks and/or debris that can damage the pipeline.
   b) Verify proper depth and width of the ditch.
   c) Ensure that the ditch is padded and levelled properly to give good support to the pipe as well as not to add any stress to the line.
3. Lower piping and tracer wire into ditch in a manner that minimizes stress to the pipe.
4. In the event of installation by trenchless excavation
   a) Ensure sufficient clearance from all other underground utilities and/or structures to allow for installation and maintenance activities going forward.
   b) Utilize device or method (weak link) to protect the plastic pipe and components from excessive force and exceeding the maximum tensile stress during the pulling process.
5. Pressure test according to WTG P-192.513 for plastic.

Installing Steel Pipe

1. Prior to beginning work in the trench and on a periodic basis while work is being performed, test the air in the trench with a certified CGI for concentrations of a combustible gaseous atmosphere which could cause an oxygen deficient atmosphere.
2. Visually inspect ditch. Make sure the ditch is free of rocks and/or debris that can damage the pipeline.
   a) Verify proper depth and width of the ditch.
   b) Ensure that the ditch is padded and levelled properly to give good support to the pipe as well as not to add any stress to the line. For trenches with significant amount of rock, the bottom of the trench shall be padded with sand or other approved padding material. Recommendation of 6” of soft padding shall be in place on the bottom of the trench to prevent projections damaging the pipe or coating.
   c) A rock shield can be used to line the ditch and/or wrap the pipe during installation to prevent coating damage.
   d) Protective shields shall be placed along the trench walls to prevent damage to the coating during lowering-in if necessary. The shields shall be removed only after the pipe is in place and subject to no further movement.
3. Welds must be X-Rayed according to WTG P-192.243 and coated prior to installation.
4. Coating must be jeeped prior to lowering into ditch and holidays repaired.
5. Install pipeline into the ditch in a manner that minimizes stress to the coating. After lowering pipe into the ditch make sure that there is adequate support. If needed use sandbags and padding dirt.

Prior to Backfilling

1. Ensure the pipe in the ditch has adequate support. If needed use sandbags and padding dirt.
2. Ensure that there is adequate sidewall clearance for proper compaction.
3. Check that desired depth identified below is met.
4. Ensure that initial backfill material is free of rocks and debris capable of damaging coating or pipe. Use sand if needed.
5. If applicable, run gauge plate pig to ensure no damage has occurred and that there are no foreign objects in pipe.
6. Pressure test according to WTG P-192.501 for steel or WTG P-192.513 for plastic

Backfilling

1. Initial Backfilling
   a) Prior to initial backfill, ensure that all damage to the protective coating and wrapping has been repaired before allowing the pipeline to be backfilled.
   b) Prior to initial backfill, ensure the pipe is adequately supported along its entire length to avoid undue stresses and backfill material does not include any stones, rock or other material which may damage the pipe or the coating.
   c) The best backfill material shall be used as soft surround for the installed pipe. Carefully place this material around the pipe and thoroughly compact until the level is 8 inches above the crown of the pipe across the full width of the trench.
2. Final Backfill
   a) The remaining excavated material of suitable quality, together with any imported material, shall be returned to the trench. The backfill material shall be heaped up along the trench line to leave a crown of 8-12 inches above adjacent ground level unless otherwise specified in the job plan.
   b) Remove surplus excavated subsoil, if any, from site or spread over the right-of-way on exposed subsoil. Do not spread surplus subsoil on topsoil.
3. Provide erosion protection if necessary.
   a) On steep slopes or any other sections of the pipeline subject to erosion where there is danger of the backfill being washed out of the trench, place sandbags in position prior to backfilling.
   b) Provide diversionary furrows if necessary to direct the flow of water into natural drainage courses and away from the pipeline trench.
4. Support against Settlement
   a) Where the pipeline emerges above ground, take special care to ensure that the buried section of the pipeline is adequately supported against settlement.
5. Backfilling of Made Roads, Footpaths and Paved Areas
   a) Backfill across highway and road cuts shall be made with selected moist backfill material which is placed in layers, thoroughly compacted by mechanical tamping unless otherwise specified in job plan.
   b) Verify that compaction has been achieved by testing crossing to permit or agreement.
6. Backfill in Irrigation and Draining Areas
   a) After backfilling the pipe trench across irrigated fields, make furrows across the backfill crown and pipeline right-of-way to maintain or reinstate the flow of irrigation or drainage water into its normal flow pattern.
   b) Where the sides of drainage or irrigation ditches are cut by the pipe trench, the ground shall be backfilled and suitably compacted so as to provide a good bond between the undisturbed sides of the drainage or irrigation ditch and the new backfill material.

7. Ensure each buried Transmission Line is provided with adequate cover.

Transmission Table **Class Location:**	**Normal soil**	**Consolidated rock**
Class 1 locations	30”	18”
Class 2, 3, and 4 locations	36”	24”
Drainage ditches of public roads and railroad crossings	36”	24”

(See regulations for exceptions)

8. Ensure each buried Distribution main line is provided with adequate cover.
   a) Except as provided in paragraph (b) of this section, each buried main line must be installed with at least 24 inches of cover.
   b) Where an underground structure prevents the installation of a line or main with the minimum cover, the line or main may be installed with less cover if it is provided with additional protection to withstand anticipated external loads.
9. Upon the completion of backfilling and cleaning up of work site, transmission lines will be subject to an above ground indirect assessment. This assessment will be performed to identify areas of coating damage incurred during the lowering and back filling process. These assessments can be accomplished by Alternating Current Voltage Gradient (ACVG) or Direct Current Voltage Gradient (DCVG) surveys or other technology. Other technologies must be approved by PHMSA per CFR 192.18 paragraph (g). **This requirement does not apply to gas gathering nor gas distribution mains.**

Installation of Service Lines

Note: Disconnected service lines that are being reinstated must be tested in the same manner as new service lines. Service lines that are temporarily disconnected from the main must be tested from the point of disconnection to the service line in the same manner as a new service line, before reconnecting. However, if provisions are made to maintain continuous service, such as installation of a bypass, any part of the original service line used to maintain continuous service does not have to be tested.

1. Ensure service lines are installed as follows:
   a) With at least 12 inches of cover on private property and at least 18 inches of cover in streets and roads. Note: If an underground structure prevents installation at these depths, the service line must be able to withstand any anticipated external loads.
   b) Properly supported on undisturbed or well-compacted soil, and the backfill that is free from materials that could damage the pipe or its coating.

c) If condensate in the gas might cause interruption in the gas supply to the customer, the service line is graded to drain into the main or into drips at the low points in the service line.

d) Minimize anticipated piping strain and external loading.

e) WTG will not install a service line through the outer foundation wall of a building.

f) WTG will not install a service line under a building.

g) Nonmetallic service lines that are not encased are provided with a means for locating them that complies with 49 CFR 192.321(e) (tracer wire installed).

h) Plastic pipe that is being encased must be inserted into the casing pipe in a manner that will protect the plastic. The leading end of the plastic pipe must be closed before insertion. In steel casing, plastic pipe must have spacers installed to prevent future damage from friction or pipe movement between the two materials.

2. Ensure that each service line has a service-line valve that meets the applicable requirements of 49 CFR 192 Subpart B and D. Note: Valves incorporated in meter bars, which allow the meter to be bypassed, are not to be used as service-line valves.

   a) This valve may not be a soft seat service line valve if its ability to control the flow of gas could be adversely affected by exposures to anticipated heat.

   b) Each service-line valve on a high-pressure distribution line, installed aboveground or in an area where the blowing of gas would be hazardous, the valve must be designed and constructed to minimize the possibility of the removal of the core of the valve with other than specialized tools.

3. Valves are to be located as follows:

   a) Service-line valve upstream of the regulator or upstream of the meter if there is no regulator.

   b) For new construction or replacement of a service line post April 14, 2017, when the installation of an EVF is not feasible, a curb valve will be installed unless the installation would add an inherent safety risk. If underground service valves are installed, they will be located in a covered durable curb box or standpipe that allows ready operation of the valve and is supported independently of the service line. All valves will be maintained consistent with all valve manufacture's specifications.

   c) Installation of the curb valve, EFV or the justification of the inherent safety risk will be documented on the Project Completion Report.

4. Ensure the following requirements are met for connections to main piping:

   a) Located at the top of the main or, if that is not practical, at the side of the main, unless a suitable protective device is installed to minimize the possibility of dust and moisture being carried from the main into the service line.

   b) Each compression type service line to main connection must.

      i. Be designed and installed to effectively sustain the longitudinal pull-out or thrust forces caused by contraction or expansion of the piping, or by anticipated external or internal loading; and

   ii. If gaskets are used in connecting the service line to the main connection fitting, have gaskets that are compatible with the kind of gas in the system; and

   iii. If service line is connected to a plastic main, a connecting fitting that provides a seal plus resistance to pullout (Category 1) is installed.

5. Ensure steel service lines that are operated at less than 100 psi are still constructed of pipe that is designed for a minimum of 100 psi.

6. Ensure that plastic service lines installed outside a building are underground unless:

   a) Risers are installed in accordance with 49 CFR 192.321 and 192.204; and

   b) The line can terminate above ground level and outside the building if:

      i. The above ground level part is protected against deterioration and external damage.

      ii. It is not used to support external loads.

      iii. Has a minimum wall thickness in accordance with 49 CFR 192.121.

      iv. Tracer wire installed.

      v. The riser portion of the service line meets the requirements of 49 CFR 192.204

7. Ensure that services lines that are constructed but not placed in service comply with one of the following until the customer is supplied with gas:

   a) The valve that is closed to prevent the flow of gas to the customer has a locking device or other means designed to prevent the opening of the valve by individuals other than those authorized by Company.

   b) A mechanical device or fitting that will prevent the flow of gas will be installed in the service line or in the meter assembly.

   c) The customer’s piping is physically disconnected from the gas supply and the ends sealed.

8. Ensure excess flow valves (EFV) meet the following requirements:

   a) If used in a single residence service line that operates continuously throughout the year at a pressure greater than 10 psi gauge, it must be manufactured and tested by the manufacturer according to an industry specification, or the manufacturer’s written specification to ensure the valve:

      i. Functions properly up to the maximum operating pressure it is rated.

      ii. Functions properly at all temperatures reasonably expected in the operating environment it is installed.

      iii. At 10 psi gauge:

         (1) It will close at or not more than 50% above the rated closure flow rate specified by the manufacturer; and

         (2) Upon closure, reduce gas flow.

(a) No more than 5% of the manufacturer's specified closure flow rate, up to a maximum of 20 cubic feet per hour if the valve is designed to all pressure to equalize across the valve; or

(b) No more than 0.4 cubic feet per hour if the valve is designed to prevent equalization of pressure across it.

iv. Does not close when the pressure is less than the manufacturer's minimum specified operating pressure and the flow rate is below the manufacturer's minimum specified closure flow rate.

b) Meets the applicable requirements of 49 CFR Subpart B-Materials and D-Design of Pipeline Components.

c) Its presence is marked or otherwise identified in the service line.

d) Is located as near as practical to the fitting connecting the service line to its source of gas supply.

e) Is not installed in a service line where there has been prior experience with contaminants in the gas stream if they could be expected to cause the valve to malfunction or where it would interfere with necessary operation or maintenance activities on the line, such as blowing liquids from the line.

f) An excess flow valve (EFV) installation must comply with the performance standards in §192.381. The operator must install an EFV on any new or replaced service line after April 14, 2017, that services:

i. A single service line to one Single Family Residence (SFR).

ii. A branched service line to a SFR installed concurrently with the primary SFR service line (*i.e.,* a single EFV may be installed to protect both service lines).

iii. A branched service line to a SFR installed off a previously installed SFR service line that does not contain an EFV.

iv. Multifamily residences with known customer loads not exceeding 1,000 SCFH per service, at time of service installation based on installed meter capacity, and

v. A single, small commercial customer served by a single service line with a known customer load not exceeding 1,000 SCFH, at the time of meter installation, based on installed meter capacity.

g) Unless one or more of the following conditions is present, then an EFV is not required:

i. If the service line operates at a pressure less than 10 psig.

ii. The operator has prior experience with contaminants in the gas stream that could interfere with the EFV's operation or cause loss of service to a customer.

iii. An EFV could interfere with necessary operations or maintenance activities.

iv. An EFV meeting the performance standards in CFR 192.381 is not commercially available.

WTG Pipe Installation Inspection
Date:
Project:
Inspector:
Signature:

Number of Joints Inspected:
Number of Holidays Found:
Number of Holidays Repaired:
Holiday Repair Method:
Number of Joints Installed:
Comments:

Tab 6

- **Project Maps, State Permits and County Permits**
- **Keep records of submittals and approvals**
- **Responsible Party: Manager or Manager Designee**

Tab 7

- **If in Texas, fill-out and Submit RRC New Construction Form PS-48 if required. See following Page. Fillable PDF must be utilized. RRC will not accept handwritten scanned documents.**
- **If in Oklahoma, fill-out Form 5001 - Notice of Construction.**
- **A link to these forms can be found on the WTG Website under WTG Operators, Construction Package – Steel.**
- **Keep records of submittal and approval**
- **Responsible Party: Manager or Manager Designee**

Texas
Pipeline Construction Reporting Requirements:
(Please see requirements below)

<u>NOTE:</u> All " new developments" or projects that will result in a new "System ID"
Will require us to notify and gain approval from the RRC 30 days prior to starting.
When requesting approval and a PO# for a new development this will need to be part of the process.

TAC "New Construction Commencement Report"	TAC 8.115	PS-48 RRC Form
Transmission Lines		
New / Relocated / Replacement	greater than 10 miles	(60) day prior notice
	1 mile to 10 miles	(30) day prior notice
Distribution Systems		
New / Relocated / Replacement	greater than 10 miles	(60) day prior notice
Relocated / Replacement/	less than 3 miles	NO notice required
New Construction(except new subdivision or new System ID)	3 miles to 10 miles	(30) day prior notice
New Construction(new subdivision or new System ID)	less than 10 miles	(30) day prior notice

Data needed for PS-48

Company	T-4 Permit (Transmission Only)	Oper ID	P-5
West Texas Gas Utility, LLC - except for Interstate	00748	22435	910284
West Texas Gas Utility, LLC - Interstate	00820	22435	910284
WTG Gas Transmission Company, LLC - all	05135	31968	945243
Western Gas Interstate Company, LLC	00835	22462	911897

PS-48 Required Y or N PS-48 Date Submitted to RRC ____________ PS-48 Date Approved by RRC ____________

5001 NOTICE OF CONSTRUCTION

OAC 165:20-5-32, OAC 165:20-7-2

Operator Name | *Operator ID*

Mailing Address

City | *State* | *ZIP Code*

Project and/or Pipeline Name

Date to Begin | *Anticipated Completion Date*

Operation Types					
Natural Gas		*Hazardous Liquid*			
Distribution	☐	Rural Regulated Gathering	☐	CO2	☐
Regulated Gathering	☐	Refinery Petroleum Products	☐	Crude	☐
Transmission	☐	HVL	☐	Non-rural Regulated Gathering	☐
MAOP/MOP (PSIG):		Pressure Test Medium:		Depth of cover:	
Installation Type: Bored & Cased ☐ Bored Only ☐ Direct Bury ☐					

Steel Pipe Specifications			
Manufacturer:			Date of Manufacturer:
Lot #:	Length:	Seam Type:	Coating Type:
Pipe Grade:	Diameter:	Wall Thickness:	

Plastic Pipe Specifications			
Manufacturer:			Date of Manufacturer:
Lot #:	Length:	Type: (IE: 2406, 4710)	Joint Type: (IE: Butt, Socket, Electro)
Diameter:	SDR:	ASTM:	

Are HCAs present?	Are HCAs/USAs present?	Performing Construction	
Gas Transmission Y ☐ N ☐	Hazardous Liquid Gathering Y ☐ N ☐	Company Personnel	☐
	Hazardous Liquid Transmission Y ☐ N ☐	Contractor	☐

***Attach a map indicating proposed route of pipeline including legal descriptions.**

Field Contact (Print Name) | *Contact Number*

Authorized Agent (Print Name) | *Signature*

Tab 8

- **Ensure project is covered by digtess grids. See 4.3.2 of the WTG's Damage Prevention Plan**
- **If not covered, send mapping department a proposed route prior to start of construction**
- **Keep a record of the email that was sent to the mapping department**
- **Responsible Party: Manager or Manager Designee**

4.3.2 New Installations or Re-routes

- Prior to re-routing a pipeline system or installing a new pipeline system, where either extends outside of the existing One Call grids, WTG will ensure the following:
    - All District Managers or their designee, will submit a "Proposed" pipeline installation route to the WTG Mapping department
    - WTG's mapping department will add the "proposed" pipeline system to the GIS mapping program
    - Once added into the GIS system, WTG will ensure the "proposed" pipeline is buffered
    - WTG will submit the new pipeline buffer to the applicable One Call Center
- During the pipeline installation process if any deviation from the original "proposed" pipeline route is necessary, the District Manager, or their designee, will submit a revised pipeline route to the WTG mapping department. The WTG Mapping department will revise the route on the GIS mapping system, and if needed, will submit a newly revised buffer for the pipeline to the applicable One Call Center.
- After the pipeline installation has been completed and finalized, WTG will ensure the following is completed:
    - All District Managers or their designee, will submit a final copy of the completed project report (Form WTG 1400) to the WTG mapping department.
    - The WTG mapping department will ensure all data which is associated with the pipeline installation project has been completed correctly and added to the GIS mapping system.
    - Once this has been completed, if any changes are necessary to the One Call grids, the WTG mapping department will submit new buffers to the applicable One Call agency.

Tab 9

- **Bids request documentation**
- **Bids**
- **Signed Contract**
- **Responsible Party: Manager or Manager Designee**

Tab 10

- **New Construction – Tasks involved with new construction are NOT considered "COVERED TASKS" and contractors do not have to be OQ Qualified during the construction of a new pipeline. However, such tasks involved with tie ins, purging, and start-up of the pipeline are considered "COVERED TASKS" and you will need to ensure personnel are OQ Qualified.**
- **Relocation/Replacements – Tasks involved with the relocation or replacement of an existing facility are considered "COVERED TASKS" and personnel involved with the Relocation/Replacement project will need to be OQ Qualified**
- **Keep qualification records of all personnel involved with Covered Tasks**
- **Responsible Party: Manager, Manager Designee, WTG Inpector or 3rd Party Inspector**

Tab 11

- **Contractors are required to follow WTG's O&M procedures**
- **Provide contractor with either a hard copy or electronic copy of the O&M procedures**
- **Ensure procedures are current by visiting the Operations/Construction section of WTG's website and verify revision dates**
- **Contractors are required to have WTG's procedures on site**
- **Document this process using the signature page that is provided in this tab**
- **Responsible Party: Manager or Manager Designee**

I, ____________________, who represents, ____________________, here by acknowledge that I have received a hard copy or electronic copy of the WTG Procedures required for this project. The copy contains the procedures listed below:

P-192.69: Storage and Handling of Pipe

P-192.105: Design of Pipelines

P-192.161: Install and Repair Support Structures and Install Insulators

P-192.225: Pipeline Welding

P-192.241: Daily Welding Inspections

P-192.243: Non-Destructive Testing of Welds

P-192.273: Joining Methods: Thread Connections

P-192.245: Repair and Removal of Weld Defects

P-192.305: General Inspection

P-192.319: Installation of Pipe in a Ditch

P-192.325: Measure Underground Clearance

P-192.351: Customer Meters, Service Regulators, and Service Lines

P-192.455: Installation of Cathodic Protection System

P-192.459: External Examination of Exposed Pipe

P-192.461: Apply and Repair External Coating

P-192.469: Corrosion Control Test Station Installation

P-192.479: Protection Against Atmospheric Corrosion

P-192.501: Steel Pipeline Pressure Test Requirements

P-192.605(b)(5): Starting Up and Shutting Down Pipeline

P-192.605(b)(9): Trench Safety

P-192.614: Damage Prevention Program (appropriate state)

P-192.619: MAOP Determination

P-192.627: Tapping Pipelines under Pressure

P-192.629: Purging or Blowing Down of a Pipeline

P-192.707: Place and Maintain Line Markers

P-192.711: Pipeline Repairs

P-192.727: Abandonment or Inactivation of Facilities

P-192.751: Prevention of Accidental Ignition

P-WTG-Hot: Hot Work

Signature: _____________________________   Date: _______________

Tab 12

- **This tab helps WTG comply with P-192.305 General Inspection and P-192.607 Verification of Pipeline Materials**
- **Inspect pipe when delivered and document on Form "WTG Pipe Inspection"**
- **Keep Bill of Lading, MTR's, invoices, pictures, etc in this section followed by Inspection Form**
- **Bill of Lading/Load Tally will be provided by pipe carrier**
- **MTR's will be provided by pipe supplier and may not always be provided when the pipe is delivered**
- **MTR's are matched to pipe by heat numbers stamped on the pipe**
- **Responsible Party: Manager, Manager Designee, WTG Inspector or 3rd Party Inspector**

Procedure Steps

1. Check components and consumables upon receipt.
   a) Ensure that they are marked properly:
      i) Each valve, fitting, length of pipe, and other component must be marked as prescribed in the specification or standard to which it was manufactured. However, thermoplastic fittings must be marked in accordance with ASTM D2513. Markings may also indicate size, material, manufacturer, pressure rating and temperature rating. Also, type, grade and model as appropriate.
      ii) Surfaces of pipe and components that are subjected to stress from internal pressure may not be field die stamped.
      iii) If any item is marked by die stamping, the die must have blunt or rounded edges that will minimize stress concentrations.
      iv) Butt-welding type fittings must meet the marking, end preparation, and the bursting strength requirements of ASME/ANSI B16.9 or MSS Standard Practice SP-75.
   b) Verify that the material received is marked as shown on the purchase document and that the material received is what was ordered. Review the documentation and verify that information agrees with purchase document requirements and material markings. Only items which meet or exceed the purchase document requirements are to be accepted by the receiving location.
   c) Maintain the purchase document number and any other appropriate identification markings on the material in a manner that does not damage the material so that the marking remains visible until the material is installed. Review markings as necessary.
   d) Cross reference mill test reports and fitting certification papers with the purchase order number. All steel pipe must have mill test reports when received and all fittings and other components must have certifications.
2. Visually inspect all pipe and components at the site to ensure that they are not damaged in a manner that could impair their strength or reduce serviceability.
3. Plastic pipe used in new construction must meet the criteria established in 49 CFR 192.63 and 49 CFR 192.123.
   a) Each valve, fitting, length of pipe and other component must be marked with its manufacturing standard, or, in the case of thermoplastic fittings, to the standards of ASTM D2513-87. All pipe must also be marked indicating size, material, manufacturer, pressure and temperature ratings, type, grade and model.
   b) All plastic pipe installed must meet the design limitations set forth in 49 CFR 192.123, including standards for temperature and pressure limitations.
   c) All installed radius fittings will meet or exceed the minimum bend radius specified by the manufacturer for the diameter of the pipe being installed.
4. Ensure welding is done in accordance with a qualified written procedure and procedure P-192.225.

WTG Pipe Inspection

Date:	
Project:	
Inspector:	
Signature:	

Pipe Description:	
Carrier:	
Number of Pieces:	

Defects:	Dents (Yes/No)	Gouges (Yes/No)	Other (Yes/No)

Number of Pieces Accepted:_____________

Number of Pieces Rejected:______________

Comments:

Tab 13

- **This tab helps WTG comply with P-192.305 General Inspection and P-192.607 Verification of Pipeline Materials**
- **Inspect components when delivered and document on Form "WTG Component Inspection" which is included in this tab**
- **Components should be delivered/picked up with MTR's**
- **If MTR's cannot be provided with certain components, documentation should be obtained to ensure components meet or exceed the design of the pipeline**
- **Keep supporting documentation such as MTR's, ANSI Rating, ASME specification, invoices, pictures, etc in this section followed by the Inspection Form**
- **Note: MTR's are matched to components by the heat numbers stamped on the components**
- **Responsible Party: Manager, Manager Designee, WTG Inspector or 3rd Party Inspector**

Procedure Steps

1. Check components and consumables upon receipt.
   a) Ensure that they are marked properly:
      i) Each valve, fitting, length of pipe, and other component must be marked as prescribed in the specification or standard to which it was manufactured. However, thermoplastic fittings must be marked in accordance with ASTM D2513. Markings may also indicate size, material, manufacturer, pressure rating and temperature rating. Also, type, grade and model as appropriate.
      ii) Surfaces of pipe and components that are subjected to stress from internal pressure may not be field die stamped.
      iii) If any item is marked by die stamping, the die must have blunt or rounded edges that will minimize stress concentrations.
      iv) Butt-welding type fittings must meet the marking, end preparation, and the bursting strength requirements of ASME/ANSI B16.9 or MSS Standard Practice SP-75.
   b) Verify that the material received is marked as shown on the purchase document and that the material received is what was ordered. Review the documentation and verify that information agrees with purchase document requirements and material markings. Only items which meet or exceed the purchase document requirements are to be accepted by the receiving location.
   c) Maintain the purchase document number and any other appropriate identification markings on the material in a manner that does not damage the material so that the marking remains visible until the material is installed. Review markings as necessary.
   d) Cross reference mill test reports and fitting certification papers with the purchase order number. All steel pipe must have mill test reports when received and all fittings and other components must have certifications.
2. Visually inspect all pipe and components at the site to ensure that they are not damaged in a manner that could impair their strength or reduce serviceability.
3. Plastic pipe used in new construction must meet the criteria established in 49 CFR 192.63 and 49 CFR 192.123.
   a) Each valve, fitting, length of pipe and other component must be marked with its manufacturing standard, or, in the case of thermoplastic fittings, to the standards of ASTM D2513-87. All pipe must also be marked indicating size, material, manufacturer, pressure and temperature ratings, type, grade and model.
   b) All plastic pipe installed must meet the design limitations set forth in 49 CFR 192.123, including standards for temperature and pressure limitations.
   c) All installed radius fittings will meet or exceed the minimum bend radius specified by the manufacturer for the diameter of the pipe being installed.
4. Ensure welding is done in accordance with a qualified written procedure and procedure P-192.225.

WTG Component Inspection
Date:
Project:
Inspector:
Signature:

Component Description:	
Supplier:	
Manufacturer:	
Number of Pieces:	

Defects: (Yes/No) _______________

Defect Description:

Number of Pieces Accepted:______________

Number of Pieces Rejected:_______________

Comments:

Tab 14

- **Record the handling and storage of pipe used for the project to ensure compliance with 192.69**
- **Document on “WTG 1400 – Project Report” which will be stored in Tab 23 of this book**
- **Responsible Party: Manager, Manager Designee, WTG Inspector or 3rd Party Inspector**

Steel Pipe Procedure Steps

Transportation & Handling Specifications:

All individuals responsible for ordering of steel pipe must inform the vendor that the pipe must be shipped in accordance with CFR 192.65. Specifically, paragraph (c) and API RP 5LT as all pipe is shipped by truck for WTG at this time. If there are any questions concerning the context of API RP 5LT, please contact the compliance department.

Handling steel pipe must document for the life of the pipeline in form WTG-1400 the method in which the pipe was handled and adhere to the procedures as described below:

1. Steel pipe shall be carefully inspected for cuts, scratches, gouges, and other imperfections within coating and pipe before use, and any pipe containing harmful imperfections shall be cut out and/or not accepted.
2. Care shall be exercised to avoid rough handling of steel pipe. It shall not be pushed or pulled over sharp projections, or it shall not have other objects dropped on it. Care shall be taken to prevent damage. In the event of damage during handling shall be removed by cutting out as a cylinder.

Qualifying Storage Specifications:

All individuals purchasing and storing steel pipe must document for the life of the pipeline the method in which the pipe was stored in form WTG-1400 and adhere to the procedures as described below:

1. Outdoor Storage – Steel pipe that is stored outdoors shall be adequately supported to prevent deformation of pipe, protected from excessive heat and harmful chemicals.
2. If pipe is ordered and received for a specific job:
   A. Upon receipt of pipe, Mill Test documentation must be reviewed and ensure that documentation matches pipe received.
   B. File Mill Test documentation in job folder for life of the pipe a central location
   C. If pipe is ordered and received for a standby / emergency repair pipe and used at a future date:
   D. Upon receipt of pipe, Mill Test documentation must be reviewed and ensure that documentation matches pipe received.
   E. File Mill Test documentation in a known location and held for future use when pie is installed.
3. Care shall be exercised at all times to protect the steel material from fire, excessive heat, or harmful chemicals.
4. Each installation shall be field inspected to detect harmful imperfections. Any such imperfections found shall be eliminated.

Tab 15

- **Verify that project design complies with P-192.105**
- **This will include such things as casing pipe, components, valves, valve spacing, etc**
- **Note: For transmission lines, emergency block valves must be spaced appropriately according to Class Location. See following documentation.**
- **Keep records of any supporting documentation**
- **Responsible Party: Manager or Manager Designee**

2	0.216	11
3	0.259	13.5
4	0.265	17
6	0.315	21
8	0.411	21
10	0.512	21
12	0.607	21
16	0.762	21
18	0.857	21
20	0.952	21
22	1.048	21
24	1.143	21

* Copper Tubing Size (CTS) Iron Pipe Size (IPS)

d) For PE pipe produced after July 14, 2004, but before January 22, 2019, a design pressure of up to 125 psig may be used, provided:
   i. The material designation code is PE2406 or PE3408.
   ii. The pipe has a nominal size (Iron Pipe Size (IPS) or Copper Tubing Size (CTS)) of 12 inches or less (above nominal pipe size of 12 inches, the design pressure is limited to 100 psig); and
   iii. The wall thickness is not less than 0.062 inches (1.57 millimeters).
e) For PE pipe produced on or after January 22, 2019, a DF of 0.40 may be used in the design formula, provided:
   i. The design pressure does not exceed 125 psig;
   ii. The material designation code is PE2708 or PE4710;
   iii. The pipe has a nominal size (IPS or CTS) of 24 inches or less; and
   iv. The wall thickness for a given outside diameter is not less than that listed in the above table.

Other plastic pipe materials will be designed according to 49 CFR 192.121.

Design of Casings:
For each casing installed on a regulated gathering, transmission or distribution main pipeline, the casing must comply with:
1. The casing must be designed to withstand superimposed loads
2. If there is a possibility of water entering the casing, the end must be sealed
3. If the ends of an unvented casing are sealed and the sealing is strong enough to retain the MAOP pressure of the pipeline, the casing must be designed to hold the pressure at a stress level of < 72% SMYS.
4. If vents are installed on casing, the vents must be protected to prevent water from entering the casing.

Pipeline Components:
Ensure each component that will be installed in the pipeline complies with the following:

1. It can withstand operating pressures and other anticipated loadings without impairment of its serviceability with unit stresses equivalent to those allowed for comparable material in pipe in the

same location and kind of service. However, if design based upon unit stresses is impractical for a particular component, design may be based upon a pressure rating established by the manufacturer by pressure testing that component or a prototype of the component. Note: These components must also meet the requirements for corrosion control requirements in Subpart I of 49 CFR Part 192.

2. If manufactured in accordance with any other edition of a document incorporated by reference in §192.7 or Appendix B of 49 CFR Part 192, -
   a) It can be shown through visual inspection of the cleaned component that no defect exists which might impair the strength or tightness of the component; and
   b) The edition of the document under which the component was manufactured has equal or more stringent requirements for the following as an edition of that document currently or previously listed in §192.7 or appendix B of 49 CFR Part 192:
      i. Pressure testing;
      ii. Materials; and
      iii. Pressure and temperature ratings.
3. Emergency Valves (49 CFR 192.145 / 19 CFR 192.179)
   a) Meet the minimum requirements of API 6D or to a national or international standard that provides an equivalent performance level. A emergency valve may not be used under operating conditions that exceed the applicable pressure-temperature ratings contained in those requirements.
   b) Can meet the anticipated operating conditions.
   c) Each transmission line has sectionalizing emergency block valves spaced as follows, unless in a particular case the Administrator finds that alternative spacing would provide an equivalent level of safety:
      i. Each point on the pipeline in a Class 4 location must be within 2 ½ miles of a valve.
      ii. Each point on the pipeline in a Class 3 location must be within 4 miles of a valve.
      iii. Each point on the pipeline in a Class 2 location must be within 7 ½ miles of a valve.
      iv. Each point on the pipeline in a Class 1 location must be within 10 miles of a valve.
         a. Each sectionalizing block valve on a transmission line complies with the following:
            - The valve and the operating device to open or close the valve are readily accessible and protected from tampering and damage.
            - The valve is supported to prevent settling of the valve or movement of the pipe to which it is attached.
         b. Each section of a transmission line between main line emergency valves has a blowdown valve with enough capacity to allow the transmission line to be blown down as rapidly as practicable. Each blowdown discharge is located so the gas can be blown to the atmosphere without hazard and, if the transmission line is adjacent to an overhead electric line, so that the gas is directed away from the electrical conductors.
         c. Each high-pressure distribution system must have emergency valves spaced so as to reduce the time to shut down a section of main in an emergency. The valve spacing is determined by the operating pressure, the size of the mains, and the local physical conditions.
         d. Each regulator station controlling the flow or pressure of gas in a distribution system must have a emergency valve installed on the inlet piping at a distance from the regulator station sufficient to permit the operation of the valve during an emergency that might preclude access to the station.
         e. Each emergency valve on a main installed for operating or emergency purposes must comply with the following:
            i. The valve must be placed in a readily accessible location so as to facilitate its operation in an emergency.

   ii. The operating stem or mechanism must be readily accessible.
   iii. If the valve is installed in a buried box or enclosure, the box or enclosure must be installed so as to avoid transmitting external loads to the main.
4. Flange or flange accessory
   a) Meet the minimum requirements of ASME/ANSI B16.5, MSS SP-44, or the equivalent.
   b) The flange assembly is able to withstand the maximum pressure at which the pipeline is to be operated and maintain its physical and chemical properties at any temperature to which it is anticipated that it might be subjected in service.
5. Threaded fittings have a minimum metal thickness that is not less than specified for the pressures and temperatures in the applicable standards referenced in 49 CFR Part 192, or their equivalent.
6. Each steel butt-welding fitting has pressure and temperature ratings based on stresses for pipe of the same or equivalent material. The actual bursting strength of the fitting is at least equal the computed bursting strength of pipe of the designated material and wall thickness, as determined by a prototype that was tested to at least the pressure required for the pipeline to which it is being added.
7. Except for branch connections and assemblies of standard pipe and fittings joined by circumferential welds, the design pressure of each component fabricated by welding, whose strength cannot be determined, is established in accordance with paragraph UG-101 of section VIII, Division 1, of the ASME Boiler and Pressure Vessel Code.
8. Each prefabricated unit that uses plate and longitudinal seams will be designed, constructed, and tested in accordance with the ASME Boiler and Pressure Vessel Code.
9. Orange-peel bull plugs and orange-peel swages are not used on pipelines that are to operate at a hoop stress of 20 percent or more of the SMYS of the pipe.
10. Except for flat closures designed in accordance with section VIII of the ASME Boiler and Pressure Code, flat closures and fish tails are not used on pipe that either operates at 100 p.s.i. gauge, or more, or is more than 3 inches nominal diameter.
11. Each welded branch connection made to pipe in the form of a single connection, or in a header or manifold as a series of connections, is designed to ensure that the strength of the pipeline system is not reduced, taking into account the stresses in the remaining pipe wall due to the opening in the pipe or header, the shear stresses produced by the pressure acting on the area of the branch opening, and any external loadings due to thermal movement, weight, and vibration.
12. Each extruded outlet is suitable for anticipated service conditions and at least equal to the design strength of the pipe and other fittings in the pipeline to which it is attached.
13. Each pipeline is designed with enough flexibility to prevent thermal expansion or contraction from causing excessive stresses in the pipe or components, excessive bending or unusual loads at joints, or undesirable forces or moments at points of connection to equipment, or at anchorage or guide points.

Passage of Internal Inspection Devices

New transmission lines and replacement of pipe and components must be designed and constructed to allow for instrumented internal inspection devices in accordance with NACE SP0102, Section 7. This requirement does not include manifolds, compressor, meter, and regulator stations, line pipe sizes that cannot accommodate ILI tools, and other exceptions listed in 49 CFR 192.150.

Launcher and receiver safety

Any launcher or receiver used after July 1, 2021, must be equipped with a device capable of safely relieving pressure in the barrel before removal or opening of the launcher or receiver barrel closure or flange and insertion or removal of in-line inspection tools, scrapers, or spheres. An operator must use a device to either: Indicate that pressure has been relieved in the barrel; or alternatively prevent opening of the barrel closure or flange when pressurized, or insertion or removal of in-line devices (*e.g.* inspection tools, scrapers, or spheres), if pressure has not been relieved.

Vaults

1. Ensure vaults meet the following structural design requirements.
   a) able to meet the loads which may be imposed upon it, and to protect installed equipment.
   b) enough working space so that all of the equipment required in the vault or pit can be properly installed, operated, and maintained.
   c) each pipe entering, or within, a regulator vault or pit is be steel for sizes 10 inch and less, except that control and gage piping may be copper. Where pipe extends through the vault or pit structure, provision must be made to prevent the passage of gases or liquids through the opening and to avert strains in the pipe.
2. Ensure each vault is located in an accessible location and, so far as practical, away from:
   a) Street intersections or points where traffic is heavy or dense;
   b) Points of minimum elevation, catch basins, or places where the access cover will be in the course of surface waters; and
   c) Water, electric, steam, or other facilities.
3. Ensure each underground vault or closed top pit containing either a pressure regulating or reducing station, or a pressure limiting or relieving station, is sealed, vented or ventilated as follows:
   a) When the internal volume exceeds 200 cubic feet:
      i. The vault or pit must be ventilated with two ducts, each having at least the ventilating effect of a pipe 4 inches in diameter;
      ii. The ventilation must be enough to minimize the formation of combustible atmosphere in the vault or pit; and
      iii. The ducts must be high enough above grade to disperse any gas-air mixtures that might be discharged.
   b) When the internal volume is more than 75 cubic feet but less than 200 cubic feet:
      i. If the vault or pit is sealed, each opening must have a tight fitting cover without open holes through which an explosive mixture might be ignited, and there must be a means for testing the internal atmosphere before removing the cover;
      ii. If the vault or pit is vented, there must be a means of preventing external sources of ignition from reaching the vault atmosphere; or
      iii. If the vault or pit is ventilated, paragraph (a) or (c) of this section applies.

Description	The purpose of this procedure is to establish a pipeline's class locations and its boundaries.
Regulatory Applicability	☒ Regulated Transmission Pipelines ☒ Regulated Gathering Pipelines (Type A) ☒ Regulated Gathering Pipelines (Type B) ☒ Unregulated Gathering ☐ Distribution Pipelines
Frequency	Upon construction and as needed thereafter due to changes in population density surrounding the pipeline as indicated by the continuing surveillance program and not to exceed two calendar years.
Reference	49 CFR 192.5 *Class Locations* 49 CFR 192.609 *Change in Class Location: Required Study* 49 CFR 192.611 *Change in Class Location: Confirmation of Maximum Operating Pressure.* LA Title 43 Part XIII 2705 *Class Locations* LA Title 43 Part XIII 2709 *Change in Class Location: Required Study* LA Title 43 Part XIII 2711 *Change in Class Location: Confirmation of Maximum Operating Pressure.* 49 CFR 192.613 *Continuing Surveillance*
Forms / Record Retention	F-192.5 *Class Location Survey / 2 years or until next review whichever is longer* F-192.619 *MAOP Determination / Life of Pipeline System*
Related Specifications	None
OQ Covered Task	None

Procedure Steps

1. Utilize previous class location(s) forms and imagery of the potentially affected segment(s). Use the attached diagrams to determine class location. Final determination of actual class location of each pipeline or pipeline segment is cooperative effort of the compliance department and district management. Electronic imagery will be reviewed annually and physical inspections will be done bi-annually.
2. Survey the area(s) to determine the current class location(s). Document the new class location on form F-192.5 or equivalent.
3. In the event of a class location change (increase), the following procedures are required:
   a) If the pipe hoop stress is not commensurate with the current class location or if the segment operates above 40% of SMYS, obtain additional information as described in 49 CFR 192.609 including:
      i) Present class location
      ii) Design, construction, and testing procedures followed in the original construction, and a comparison of these procedures with those required for the present class location;
      iii) The physical condition of the segment to the extent it can be ascertained from available records;
      iv) The operating and maintenance history of the segment;
      v) The MAOP and the corresponding operating hoop stress, taking pressure gradient into account, for the segment of pipeline involved; and
      vi) The actual area affected by the population density increase, and physical barriers or other factors which may limit further expansion of the more densely populated area.
4. Determine if the pipe MAOP and corresponding pipe hoop stress is acceptable for the current class location. Refer to procedure P-192.619.
5. If the hoop stress corresponding to the established MAOP of the segment does not commensurate with the present class location, but the segment is in satisfactory condition, the MAOP will be confirmed or revised as follows:
   a) If the segment has been previously tested in place for at least 8 hours, the MAOP is the pressure obtained by multiplying the test pressure by the following factors:
      i) 0.8 in Class 2 locations,
      ii) 0.667 in Class 3 locations
      iii) 0.555 in Class 4 locations.

      Note the hoop stress cannot exceed"

      - 72% of SMYS in Class 2 locations
      - 60% of SMYS in Class 3 locations; or
      - 50% of SMYS in Class 4 locations.

b) Reduce the MAOP so that the hoop stress is not more than that allowed for new segments of pipelines in the class location

c) Test the segment involved in accordance with 49 CFR Subpart J; and establish the MAOP according to the following material:

i) Multiply the test pressure times the following factors:

(1) 0.8 in Class 2 locations,

(2) 0.667 in Class 3 locations

(3) 0.555 in Class 4 locations.

ii) The hoop stress may not exceed:

(1) 72% of SMYS in Class 2 locations

(2) 60% of SMYS in Class 3 locations; or

(3) 50% of SMYS in Class 4 locations.

NOTE: The confirmed or revised MAOP, may not exceed the previous MAOP.

NOTE: 24 months are available to make revisions to the MAOP.

NOTE: Additional pressure testing of the segment may be desirable to raise the MAOP of the pipeline to a higher level. Schedule and conduct the pressure testing as desirable.

Class Location Determination

Gas pipelines are placed in class locations as described below. These classifications help determine some of the regulated activities that must be performed on the pipeline and the frequency of the activity. The Class Location Unit is an area extending six hundred and sixty feet (660) on either side of the centerline of any continuous one (1) mile length of pipeline.

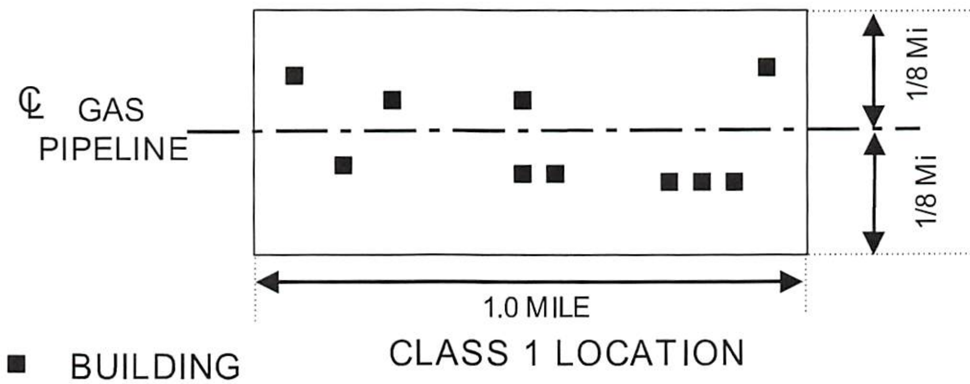
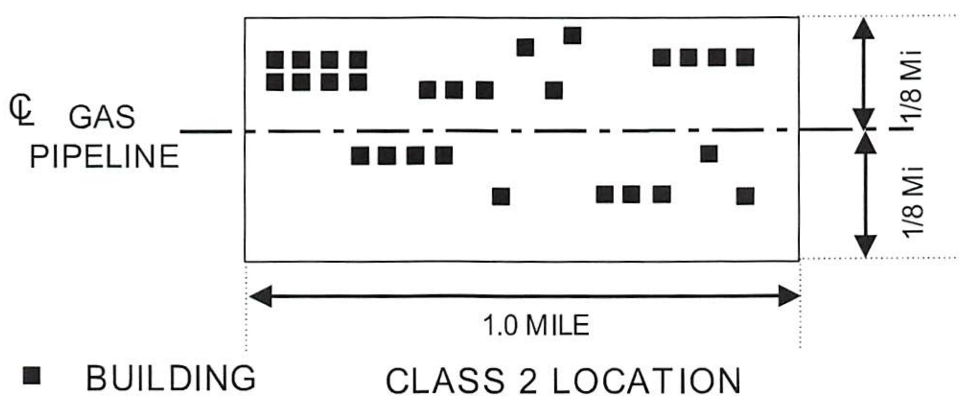
Class location studies will be conducted:

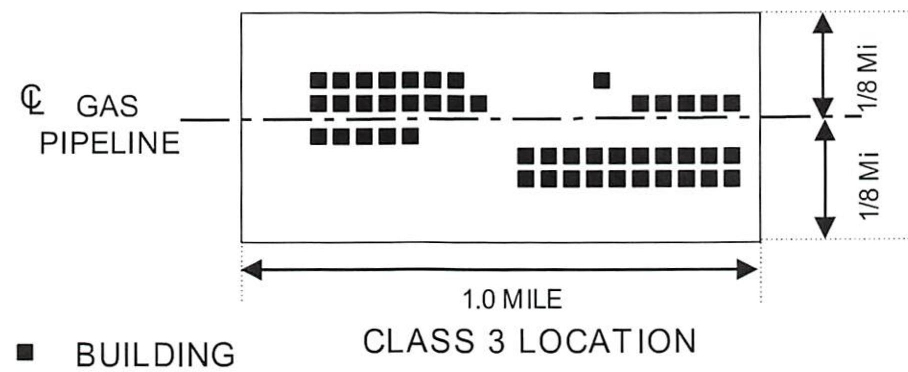
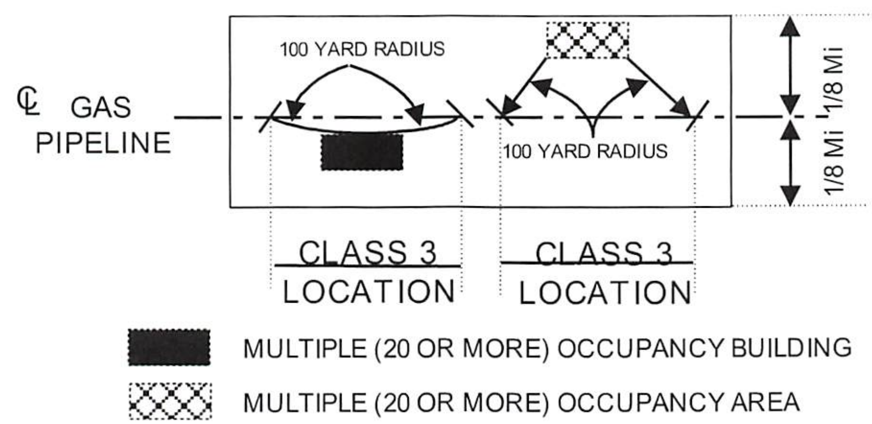
a) For each existing pipeline or pipeline segment

b) For each new pipeline or pipeline segment being constructed, and prior to testing. The class location determines in part, the maximum allowable operating pressure of the pipeline or pipeline segment.

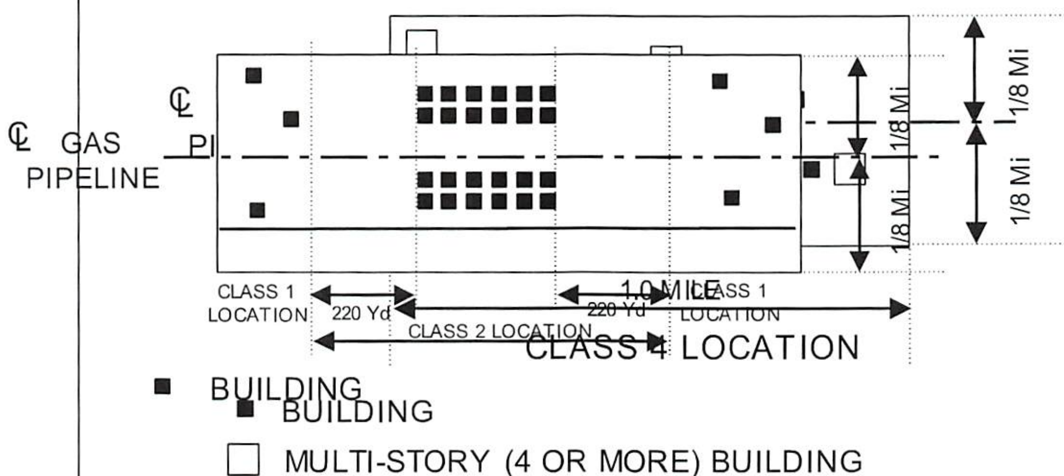
c) Whenever patrols or surveillance indicate changes in population density along the pipeline route.

The class location of onshore pipelines is broken up as follows:

Class Location	Criteria (Class Location Unit contains)
1	Has ten (10) or fewer buildings intended for human occupancy. 
2	Has more than ten (10) and fewer than forty-six (46) buildings intended for human occupancy. 

Class Location	**Criteria** (Class Location Unit contains)
3	Has forty-six (46) or more buildings intended for human occupancy; or 
3	An area where the pipeline lies within 300 feet of either a building or a small well-defined outside area (i.e., playground, recreation area, outdoor theater, or other place of public assembly that is occupied by twenty (20) or more people at least five (5) days per week for ten (10) weeks per twelve (12) month period. The days and weeks do not need to be consecutive. 

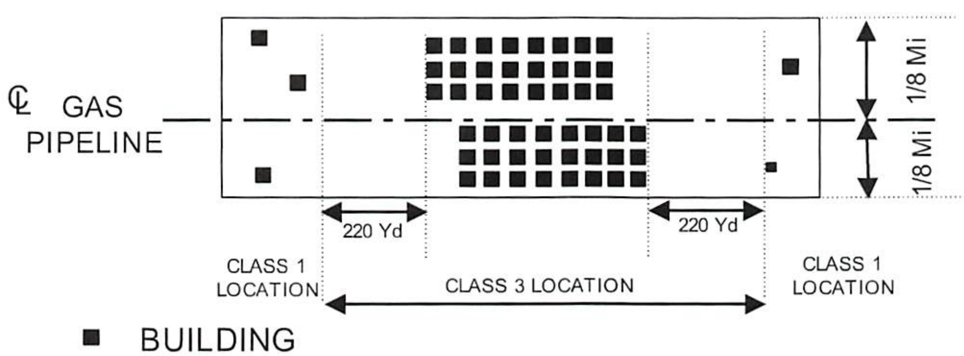
Class Location	Criteria (Class Location Unit contains)
4	Dwellings with four (4) or more stories above ground are prevalent.



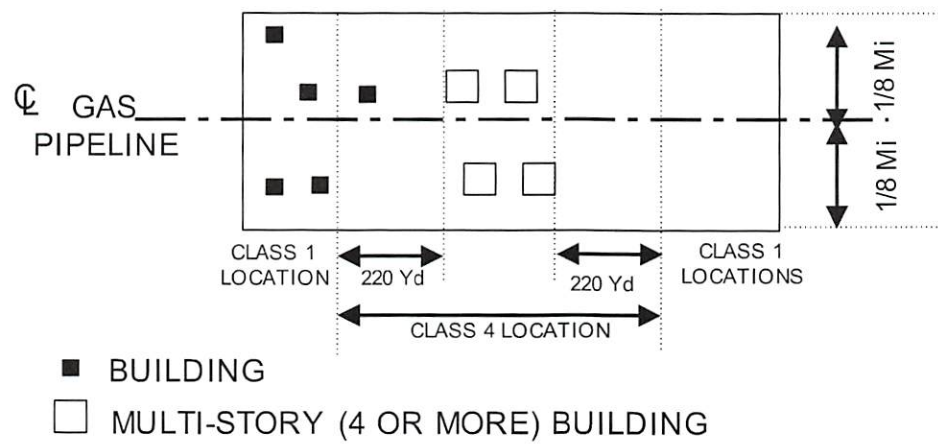
Class Location Unit Boundaries

The boundaries of the class location unit are adjusted as follows:

1. Class 2 and 3 locations end 660 feet from the nearest building in the cluster of buildings that require the class location.



2. Class 4 location ends 660 feet from the nearest building with four (4) or more stories above ground.



Tab 16

- **Verify that the design of the pipeline is protected against accidental over pressuring (P-192.105)**
- **If regulators and reliefs were added, document on WTG 1102 and maintain in the Compliance Records**
- **Responsible Party: Manager or Manager Designee**

Protection against accidental overpressuring

General requirements

Except as provided in §192.197, ensure each pipeline that is connected to a gas source so that the maximum allowable operating pressure could be exceeded as the result of pressure control failure or of some other type of failure, has pressure relieving or pressure limiting devices that meet the requirements below.

Additional requirements for distribution systems

Ensure each distribution system that is supplied from a source of gas that is at a higher pressure than the maximum allowable operating pressure for the system -

(1) Has pressure regulation devices capable of meeting the pressure, load, and other service conditions that will be experienced in normal operation of the system, and that could be activated in the event of failure of some portion of the system; and

(2) Is designed so as to prevent accidental overpressuring.

Control of the pressure of gas delivered from high-pressure distribution systems

1. If the maximum actual operating pressure of the distribution system is 60 p.s.i. gage, or less and a service regulator having the following characteristics is used, no other pressure limiting device is required:

    a) A regulator capable of reducing distribution line pressure to pressures recommended for household appliances.
    b) A single port valve with proper orifice for the maximum gas pressure at the regulator inlet.
    c) A valve seat made of resilient material designed to withstand abrasion of the gas, impurities in gas, cutting by the valve, and to resist permanent deformation when it is pressed against the valve port.
    d) Pipe connections to the regulator not exceeding 2 inches (51 millimeters) in diameter.
    e) A regulator that, under normal operating conditions, is able to regulate the downstream pressure within the necessary limits of accuracy and to limit the build-up of pressure under no-flow conditions to prevent a pressure that would cause the unsafe operation of any connected and properly adjusted gas utilization equipment.
    f) A self-contained service regulator with no external static or control lines.

2. If the maximum actual operating pressure of the distribution system is 60 p.s.i. gage, or less, and a service regulator that does not have all of the characteristics listed in paragraph (a) of this section is used, or if the gas contains materials that seriously interfere with the operation of service regulators, there must be suitable protective devices to prevent unsafe overpressuring of the customer's appliances if the service regulator fails.

WTG

Gas Operations and Maintenance Manual

FORM WTG-1102

Regulator Station Inspection Sheet

District ____ System ____ TRC/CC UNIT ____

STATION NBR ____ LOCATION ____ GPS ____

STATION TYPE: SINGLE CUT ___ SERIES CUT PARALLEL ___ MONITOR ___ WORKING MONITOR ___ MAOP ____ IN ___ OUT ___

REGULATOR DATA NO. 1

Size ____ Make ____
Model # ____ S/N ____
Press Rating ____ Orifice Size ____
Spring Color ____ Spring Range ____
In Press Max ____
Out Press Max ____

REGULATOR DATA NO. 2

Size ____ Make ____
Model # ____ S/N ____
Press Rating ____ Orifice Size ____
Spring Color ____ Spring Range ____
In Press Max ____
Out Press Max ____

REGULATOR DATA NO. 3

Size ____ Make ____
Model # ____ S/N ____
Press Rating ____ Orifice Size ____
Spring Color ____ Spring Range ____
In Press Max ____
Out Press Max ____

REG CAPACITY

At Max Inlet & MAOP Outlet SCFH #1 ____ #2 ____ #3 ____

Relief Valve Data No. 1

Size ____ Make ____
Model # ____ Press Rating ____
Spg Color ____ Range ____

Relief Valve Data No. 2

Size ____ Make ____
Model # ____ Press Rating ____
Spg Color ____ Range ____

Relief Valve Data No. 3

Size ____ Make ____
Model # ____ Press Rating ____
Spg Color ____ Range ____

Capacity Downstream at MAOP SCFH #1 ____ #2 ____ #3 ____

INSPECTION SHEET

	Y	N	N/A
Bypass Locked Closed?	☐	☐	☐
RV Locked Open?	☐	☐	☐
Building Okay?	☐	☐	☐
Fence secure?	☐	☐	☐
Weeds cut?	☐	☐	☐
Bypass valve oper. & serviced?	☐	☐	☐
Caution signs in place & legible?	☐	☐	☐
All vents clear & protected?	☐	☐	☐
Inlet valve oper. & serviced?	☐	☐	☐
Outlet valve oper. & serviced?	☐	☐	☐
Slam valve insp & cleaned?	☐	☐	☐
Regulators stroked?	☐	☐	☐
Lockup checked?	☐	☐	☐
Orfice working properly?	☐	☐	☐
Seats working properly?	☐	☐	☐
Relief valve popped?	☐	☐	☐
Relief valve insp & cleaned?	☐	☐	☐
Was Nitrogen used?	☐	☐	☐
Paint Okay?	☐	☐	☐
Atmospheric corrosion present?	☐	☐	☐
Filter replaced / cleaned?	☐	☐	☐
Relief Blk Valve oper & serviced?	☐	☐	☐

Regulator Settings As Left

Reg No 1 ____ psi Reg No 2 ____ psi Reg No 3 ____ psi

Relief Valve Settings as Left

Rel No 1 ____ psi Rel No 2 ____ psi Rel No 3 ____ psi

Slam Valve Settings As Left

____ psi ____ ppm ____ other

Date Inspected ____ AOC's Found Y ☐ N ☐ Person Qualified? Y ☐ N ☐

Note: This inspection sheet must agree with the equipment installed. Any changes to MAOP, orifice size, relief valves, orfices or springs require revisions to the sheet and the regulator design sheet. Is there anything on the station that does not agree with this form, or is not consistent with the operation conditions? Y ☐ N ☐ If yes, please note in REMARKS on back of this form(if needed check here) ☐

Inspector Signature ____ AOC's Y ☐ N ☐

Reviewing Supervisor ____

Revised: May 2022

WTG

Tab 17

- **Fill out and keep F-192.619 – MAOP Determination**
- **Excel Version of F-192.619 is preferred. Formulas are built in to aid in calculation. The link to the worksheet can be found on WTG's website by clicking on WTG O&M, then Operations and Maintenance Forms, then click on F-192.619 MAOP Determination (Steel).   The form will open in an xcel version.**
- **After completing worksheet, print and file under this tab.**
- **Responsible Party: Manager or Manager Designee**

Form F-192.619
Poly Pipe MAOP Determination
Revision January 2022

System Information

Company:		Distrtict:	
Pipeline System :		Class Location:	
Segment:		GPS Coordnates:	Start: / End:
Pipe Material:	System MAOP: 0.00	Nominal O.D. (in.):	
Wall Thickness:		Pipe Grade:	
Pipe Class:		Length (ft.):	
Pipe Manufacturer:		Max. Operating Temp. (°F):	
Year Manufactured:	Year Purchased:	Test Pressure after Construction:	
Thermoplastic Pipe Value (psi):		Test Press. Factor:	1.5
Internal Design Press. (psi):		ASME/ANSI Flange Rating:	
Seam Joint Factor:		SDR Value:	Design Factor:

List specifications/standards that the pipe and/or components were designed/constructed under. (49 CFR 192.303):

Comments:	
Determination Factor; (a)(1) (a)(2) (a)(3) or (a)(4)	
* If (a)(4) was selected, why?	Explain:
Signature:	Date:

WTG

Form F-192.619

Poly Pipe MAOP Determination

MAOP Calculation

1. Results of Design Pressure calculations, Step 10. (See attached Worksheet) **(a)(1)**		psi.
3. Flange Pressure Rating. **(a)(1)**		psi.
4. Flanged Valve Pressure Rating. **(a)(1)**		psi.
5. Design Pressure of any other component if less than flange or valve rating. **(a)(1)**		psi.
5.(a) Description of component entered on line 5. Relief valve, regulator, etc		
2. Results of Test Pressure calculations, Step 3. (See attached Worksheet) **(a)(2)**		psi.
8. Notwithstanding the other requirements of this section, an operator may operate a segment of pipeline found to be in satisfactory condition, considering its operating and maintenance history, at the highest actual operating pressure to which the segment was subjected during the last 5 years preceeding the applicable date in the second column of the table listed in Procedure P-192.619. If this applies enter the appropriate pressure here. **(a)(3)**		psi.
7. The pressure determined by the operator to be the maximum safe pressure after considering the history of the segment, particularly known corrosion, and the actual operating pressure. **(a)(4)** * Note: Over-Pressure protective devices must be installed on the segment in a manner that will prevent the maximum allowable operating pressure from being exceeded in accordance with 49 CFR 192.195.		psi.
10. The Pipeline MAOP is the lowest of steps 1-8 above, or the pressure from step 9 above. **MAOP =**	**0.00**	psi.

Note: If the MAOP is being re-calculated due to a change in class location, refer to Form F-192.611.
Note: Any flanged or steel fitting used will have a higher pressure rating than PE pipe.
Note: Additional requirements apply to distribution systems. See 49 CFR 192.621 and 192.623, if necessary.

Design Pressure Calculations Worksheet (49 CFR 192.121)

1.Thermoplastic Pipe Value (S) The hyrdrostatic design basis (HDB) is determined in accordance with the listed specification at a temperature equal to 73 °F (23 °C), 100 °F (38 °C), 120 °F (49 °C), or 140 °F (60 °C). In the absence of an HDB established at the specified temperature, the HDB of a higher temperature may be used in determining a design pressure rating at the specified temperature by arithmetic interpolation using the procedure in Part D.2 of PPI TR-3/2008, HDB/PDB/SDB/MRS Policies (incorporated by reference, see § 192.7). For reinforced thermosetting plastic pipe, 11,000 psig (75,842 kpa).
[**Note**: Arithmeticinterpolation is not allowed for PA-11 pipe]

Pipe Grade	Design Temp (°F)			
	73	**100**	**120**	**140**
2306	1250	1250	1000	800
2406	1250	1250	1000	800
3406	1250	1250	1000	800
3408	1600	1250	1000	800
4710	1600	1250	1000	800

Highlighter the criteria used above to determine the thermoplastic pipe value, and enter here.	**S=**		**psi.**

2. Nominal Wall Thickness (t) (49 CFR 192.109)

This is the nominal wall thickness of the pipe in inches, as described in the applicable pipe specification.

a) If the nominal wall thickness for steel pipe is not known, it is determined by measuring the thickness of each piece of pipe at quarter points on one end.

b) However, if the pipe is of uniform grade, size, and thickness and there are more than 10 lengths, only 10 percent of the individual lengths, but not less than 10 lengths, need to be measured. The thickness of the lengths that are not measured must be verified by applying a gauge set to a minimum thickness found by the measurement. The nominal wall thckness to be used in the design formula is the next wall thickness found in commercial specifications that is below the average of all the measurements taken. However, the nominal wall thickness used may not be more than 1.14 times the smallest measurement taken on pipe less than 20 inches in outside diameter, nor more than 1.11 times the smallest measurement taken on pipe 20 inches or more in outside diameter.

Note: Additional wall thickness required for concurrent external loads in accordance with 49 CFR 192.103 may not be included in computing design pressure.

Circle the criteria used above to determine the Nominal Wall Thickness, and enter here.	t=		**in.**

WTG

Form F-192.619

Poly Pipe MAOP Determination

3. Standard Dimension Ratio (SDR)

Standard dimension ratio, the ratio of the average specified outside diameter to the minimum specified wall thickness, corresponding to a value from a common numbering system that was derived from the American National Standard Institute preferred number series 10.

PE Pipe - Minimum Wall Thickness and SDR Values

Pipe size (inches)	Minimum wall thickness (inches)	Corresponding SDR (values)
1/2 CTS	0.09	7
1/2 IPS	0.09	9.3
3/4 CTS	0.09	9.7
3/4 IPS	0.095	11
1 CTS	0.099	11
1 IPS	0.119	11
1 1/4 IPS	0.151	11
1 1/2 IPS	0.173	11
2	0.216	11
3	0.259	13.5
4	0.265	17
6	0.315	21
8	0.411	21
10	0.512	21
12	0.607	21
16	0.762	21
18	0.857	21
20	0.952	21
22	1.048	21
24	1.143	21

* Copper Tubing Size (CTS) Iron Pipe Size (IPS)

Highlight the criteria used above to determine the SDR value, and enter here.	**SDR =**	

WTG

Form F-192.619

Poly Pipe MAOP Determination

4. Design Factor (DF) DF = 0.32 or PE pipe produced after January 22, 2019, a DF of 0.40 may be used in the design fomula, provided one of the following requirements are met: 1) The design pressure does not exceed 125 psig; 2) The material designation code is PE2708 or PE4710; 3) The pipe has a nominal size (IPS or CTS) of 24 inches or 4) The wall thickness for a given outside diameter is not less than that listed in the table listed in 3. Standard Dimension Ratio (SDR) For Polyamide (PA-11) and Polyamide (PA-12) refrence CRF 129.121 (d) & (e)	
Highlight the Criteria used above to determine the Design Factor, and Enter here.	**DF=**

5. Nominal Outside Diameter (D)		
Enter the Nominal Outside Diameter of the pipe in inches here.	D=	
6. Design Pressure - Nominal (P) Use the results of steps 1-5 above in the following formula to calculate the nominal design pressure. $P = \frac{2 * S * t}{D-t} * DF$		
P= 2 * ______ * -	P=	

Test Pressure Calculation Worksheet

1. Test Pressure after construction		**psi.**
2. Test Derating Factor Plastic Pipe = 1.5		
3. MAOP Limited by Test Pressure Line 1 divided by Line 2		**psi.**

Operating Pressures for Flanged Valves (if applicale)			
ANSI Class	Maximum Operating Pressure	Hydrostatic Test Pressure	
		Shell	Seat

Operating and Pressures for Flanges (if applicale)		
ANSI Class	Maximum Operating Pressure	Hydrostatic Test Pressures

Pressure test calcualtion results		Design Pressure Results	

Is Any Component being Installed that has a lower MAOP than row 192 other than a flange or flanged valve?			
Description of Component	ANSI Class	Maximum operating Pressure	

Temporary Piping Blinds Blind Thickness (Inches) for Flange Sizes * Blinds Cut from ASTM A36 Carbon Steel Plate for Maximum Actual Hydrostatic Pressure as Given						
Nominal Pipe Size	ANSI 150	ANSI 300	ANSI 600	ANSI 900	ANSI 1500	ANSI 2500
	285 psig	740 psig	1480 psig	2220 psig	2500 psig	3000 psig

Tab 18

- **Pressure test pipeline and any above ground fabrication in accordance with P-192.501**
- **Document on F-192.517 or equivalent & keep all records in this tab. Charts, forms, etc**
- **Note: if the pipe used in above ground fabrication is tested in accordance with P-192.501 prior to being used in above ground fabrication, the above ground fabrication does not have to be retested provided that you x ray 100% of the welds on the above ground fabrication. Components with supporting MTR's do not have to be retested. Pipe used in above ground fabrication is normally tested separately from the newly installed underground pipeline.**
- **Responsible Party: Manager, Manager Designee, WTG Inspector or 3rd Party Inspector**

Form F-192.619

MAOP Determination
Revision January 2022

System Information

Company:			**Distrtict:**		
Pipeline System :			**Class Location:**		
Segment:			**GPS Coordnates:**	**Start:**	
				End:	
Pipe Material:	**System MAOP:**	**#DIV/0!**	**Outside Diameter (in.):**		
Wall Thickness:			**Pipe Grade:**		
Pipe Class:			**Length (ft.):**		
Pipe Manufacturer:			**Max. Operating Temp. (°F):**		
Year Manufactured:			**Year Purchased:**		
Yield Strength:			**Design Temp:**		
Internal Design Press. (psi.):			**Test Press. Factor:**		
Seam Joint Factor:			**ASME/ANSI Flange Rating:**		
			Percent SMYS	**#DIV/0!**	
List specifications/standards that the pipe and/or components were designed/constructed under. (49 CFR 192.303):					
Comments:					
Determination Factor; (a)(1) (a)(2) (a)(3) or (a)(4)					
* **If (a)(4) was selected, why?**		**Explain:**			
Is this pipeline In Line Inspectable (ILI Capable)?					
Signature:			**Date:**		

***NOTE* If MAOP Changes, The Percent of SMYS Needs to be Reevaluated!**

Form F-192.619
MAOP Determination

MAOP Calculation

1. Results of Design Pressure calculations, Step 10. (See attached Worksheet) **(a)(1)**		psi.
3. Flange Pressure Rating. **(a)(1)**		psi.
4. Flanged Valve Pressure Rating. **(a)(1)**		psi.
5. Design Pressure of any other component if less than flange or valve rating. **(a)(1)**		psi.
5.(a) Description of component entered on line 5. Relief valve, regulator, etc		
2. Results of Test Pressure calculations, Step 3. (See attached Worksheet) **(a)(2)**	**#DIV/0!**	psi.
8. Notwithstanding the other requirements of this section, an operator may operate a segment of pipeline found to be in satisfactory condition, considering its operating and maintenance history, at the highest actual operating pressure to which the segment was subjected during the last 5 years preceeding the applicable date in the second column of the table listed in Procedure P-192.619. If this applies enter the appropriate pressure here. **(a)(3)**		psi.
7. The pressure determined by the operator to be the maximum safe pressure after considering the history of the segment, particularly known corrosion, and the actual operating pressure. **(a)(4)** * Note: Over-Pressure protective devices must be installed on the segment in a manner that will prevent the maximum allowable operating pressure from being exceeded in accordance with 49 CFR 192.195.		psi.
10. The Pipeline MAOP is the lowest of steps 1-8 above, or the pressure from step 9 above. **MAOP =**	**#DIV/0!**	psi.

Note: If the MAOP is being re-calculated due to a change in class location, refer to Form F-192.611.

Note: Additional requirements apply to distribution systems. See 49 CFR 192.621 and 192.623, if necessary.

Design Pressure Calculations Worksheet (49 CFR 192.105)

Note: Steel pipe in pipelines that have been converted under 49 CFR 192.14 or uprated under Subpart K and have any variable necessary to determine the design pressure unknown, one of the following pressures is to be used as the design pressure:

• 80% of the first test pressure that produces yeild under Section N5 of Appendix N of ASME B31.8, reduced by the appropriate factor in
the table on the Test Pressure Calculation Worksheet: or

• If the pipe is 12 3/4 inches or less in diameter and is not tested to yield, 200 psi.

1. Yeild Strength (S) (49 CFR 192.107)

a) For the pipe that is manufactured in accordance with a specification listed in section I of appendix B of 49 CFR Part 192, the yield strength to be used in the design formula is the SMYS stated in the listed specification, if that value is known.

b) For pipe that is manufactured in accordance with a specification not listed in section I of appendix b of 49 CFR Part 192, or whose specification or tensile properties are unknown, the yield strength to be used in the design formula is one of the following:

(1) If the pipe is tensile tested in accordance with section II-D of appendix B of 49 CFR Part 192, the lower of the following:

(i) 80 percent of the average yield strength determined by the tensile tests.

(ii) The lowest yield strength determined by the tensile tests.

(2) If the pipe is not tensile tested as provided in paragraph (b)(1) of this section, 24,000 psi.

Circle the criteria used above to determine the pipe yield strength, and enter here.		**psi.**

2. Nominal Wall Thickness (t) (49 CFR 192.109)

This is the nominal wall thickness of the pipe in inches, as described in the applicable pipe specification.

a) If the nominal wall thickness for steel pipe is not known, it is determined by measuring the thickness of each piece of pipe at quarter points on one end.

b) However, if the pipe is of uniform grade, size, and thickness and there are more than 10 lengths, only 10 percent of the individual lengths, but not less than 10 lengths, need to be measured. The thickness of the lengths that are not measured must be verified by applying a gauge set to a minimum thickness found by the measurement. The nominal wall thckness to be used in the design formula is the next wall thickness found in commercial specifications that is below the average of all the measurements taken. However, the nominal wall thickness used may not be more than 1.14 times the smallest measurement taken on pipe less than 20 inches in outside diameter, nor more than 1.11 times the smallest measurement taken on pipe 20 inches or more in outside diameter.

Note: Additional wall thickness required for concurrent external loads in accordance with 49 CFR 192.103 may not be included in computing design pressure.

Circle the criteria used above to determine the Nominal Wall Thickness, and enter here.	**t=**		**in.**

3. Design Factor (F) (49 CFR 192.111)

a) Except as otherwise provided in paragraphs (b), (c) or (d) below, the design factor to be used in the design formula is determined in accordance with the following table:

Class Location	Design Factor (F)
1	0.72
2	0.6
3	0.5
4	0.4

Before chosing design pressure, be sure and review b), c) and d) below.

b) A desgin factor of 0.60 or less must be used in the design formula for steel pipe in Class 1 locations that:

(1) Crosses the right-of-way of an unimproved public road, without a casing;
(2) Crosses without a casing, or makes a parallel encroachment on, the right-of-way of either a hard surfaced road, a highway, a public street, or a railroad;
(3) Is supported by a vehicular, pedestrian, railraod, or pipeline bridge; or
(4) Is used in a fabricated assembly, (including seperators, mainline valve assemblies, cross-connections, and river crossing headers) or is used within five pipe diameters in any direction from the last fitting of a fabricated assembly, other than a transition piece or an elbow used in place of a pipe bend which is not associated with a fabricated assembly.

c) For Class 2 locations, a design factor of 0.50, or less, must be used in the design formula for uncased steel pipe taht crosses the right-of-way of a hard surfaced road, a highway, a public street, or a railroad.

d) For Class 1 and 2 locations, a design factor of 0.50, or less, must be used in the design formula for:

(1) Steel pipe in a compressor station, regulating station, or measuring stations, and;
(2) Steel pipe, including a pipe riser, on a platform located offshore or in inland navigable waters.

Circle the criteria used above to determine the design factor, and enter here.	**F =**	

4. Longitudinal Joint Factor (E): (49 CFR 192.113)
The longitudinal joint factor to be used in the design formula is determined in accordance with the following table:

Specification and Pipe Class	Longitudinal Joint Factor

If the type of longitdinal joint cannot be determined, the joint factor to be used must not exceed that designated for "Other"

Circle the Criteria used above to determine the Longitudianl Joint Factor, and Enter here.	**E=**	

5. Temerature Derating Factor (T) (49 CFR 192.115)
The temperature derating factor to be used in the design formula is determined as follows:

Gas Temperature	Temperature Derating Factor (T)

For immediate gas temperatures, the derating factor is determined by interpolation.

Circle the Criteria used above to determine the Temperature Derating Factor, and Enter here. **T=**

6. Nominal Outside Diameter (D)

Enter the Nominal Outside Diameter of the pipe in inches here. **D=**

7. Design Pressure - Nominal (P)

Use the results of steps 1-5 above in the following formula to calculate the nominal design pressure.

$$P = \frac{2 * S * t}{D} * F * E * T$$

P= $\frac{2 \quad * \quad\quad *}{\quad\quad\quad\quad}$ * * * **P=**

8. Design Pressure - adjustment (P) If steel pipe that has been subjected to cold expansion to meet the SMYS is subsequently heated, other than by welding or stress relieving as a part of welding, the design pressure is limited to 75% of the pressure determined above, if the temperature of the pipe exceeds 900°F (482°C) at any time or is held above 600°F (316°C) for more than one hour.	
If applicable, multiply the result from step 7 by 0.75, and enter the result here:	**P= N/A**
9. Alternative Design Pressure (P) For steel pipelines being converted under 49 CFR 192.14, or uprated under 49 CFR 192 Subpart K, if any variable necessary to determine the design pressure as calculated in steps 1-7 is unknown, one of the following pressures is to be used as the design pressure: (i) Eighty percent of the first test pressure that produces yield under section N5.0 of Appendix N of ASME B31.8, reduced by the appropriate factor in Table 1 of the Test Pressure Calculations; or (ii) If the pipe is 324 mm (12 3/4 in) or less in outside diameter and is not tested to yield under this paragraph, 1379 kPa (200psig)	
If applicable, circle the criteria used above to determine the design pressure and enter it here:	**P= N/A**
10. Design Pressure - Final (P)	
Select the appropriate design pressure from steps 7, 8, or 9 and enter it here:	**P=**

Test Pressure Calculation Worksheet

1. Test Pressure after construction	**3000**	**psi.**

2. Test Derating Factor

Plastic Pipe = 1.5
Steel Pipe:
If the pipeline is operated at 100 psig or more, select the appropriate factor from below:

Class Location	Factors		
	Installed before Nov. 12, 1970	Installed after Nov. 11, 1970	Converted under §192.14

Test Derating Factor =	

If the Pipeline is operated below 100 psig, enter 1.0 as the test derating factor.

3. MAOP Limited by Test Pressure Line 1 divided by Line 2	**#DIV/0!**	**psi.**

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

Operating and Hydrostatic Test Pressures for Valves			
ANSI Class	Maximum Operating Pressure	Hydrostatic Test Pressure	
		Shell	Seat

Operating and Hydrostatic Pressures for Flanges		
ANSI Class	Maximum Operating Pressure	Hydrostatic Test Pressures

Components with a Design Pressure Less Than the Valve or Flange Rating (If Applicable)			
Description of Component	ANSI Class	Maximum operating Pressure	Hydrostatic Test Pressure

Temporary Piping Blinds Blind Thickness (Inches) for Flange Sizes * Blinds Cut from ASTM A36 Carbon Steel Plate for Maximum Actual Hydrostatic Pressure as Given						
Nominal Pipe Size	ANSI 150	ANSI 300	ANSI 600	ANSI 900	ANSI 1500	ANSI 2500
	285 psig	740 psig	1480 psig	2220 psig	2500 psig	3000 psig

WTG

Tab 19

- **If required, complete an Indirect Assessment of the newly laid Transmission line to identify areas of coating damage that the pipe may have incurred during the lowering and back filling process**
- **Note: If the onshore transmission line construction project involves 1,000 feet or more of continuous backfill length along the pipeline, within 6 months, the operator must perform an assessment to assess any coating damage and ensure integrity of the coating using direct current voltage gradient (DCVG), alternating current voltage gradient (ACVG), or other technology that provides comparable information about the integrity of the coating**
- **Keep supporting documentation in this tab**
- **Responsible Party: Manager or Manager Designee**

7. Ensure each buried Transmission Line is provided with adequate cover.

Transmission Table Class Location:	Normal soil	Consolidated rock
Class 1 locations	30"	18"
Class 2, 3, and 4 locations	36"	24"
Drainage ditches of public roads and railroad crossings	36"	24"

(See regulations for exceptions)

8. Ensure each buried Distribution main line is provided with adequate cover.
   a) Except as provided in paragraph (b) of this section, each buried main line must be installed with at least 24 inches of cover.
   b) Where an underground structure prevents the installation of a line or main with the minimum cover, the line or main may be installed with less cover if it is provided with additional protection to withstand anticipated external loads.
9. Upon the completion of backfilling and cleaning up of work site, transmission lines will be subject to an above ground indirect assessment. This assessment will be performed to identify areas of coating damage incurred during the lowering and back filling process. These assessments can be accomplished by Alternating Current Voltage Gradient (ACVG) or Direct Current Voltage Gradient (DCVG) surveys or other technology. Other technologies must be approved by PHMSA per CFR 192.18 paragraph (g). **This requirement does not apply to gas gathering nor gas distribution mains.**

Installation of Service Lines

Note: Disconnected service lines that are being reinstated must be tested in the same manner as new service lines. Service lines that are temporarily disconnected from the main must be tested from the point of disconnection to the service line in the same manner as a new service line, before reconnecting. However, if provisions are made to maintain continuous service, such as installation of a bypass, any part of the original service line used to maintain continuous service does not have to be tested.

1. Ensure service lines are installed as follows:
   a) With at least 12 inches of cover on private property and at least 18 inches of cover in streets and roads. Note: If an underground structure prevents installation at these depths, the service line must be able to withstand any anticipated external loads.
   b) Properly supported on undisturbed or well-compacted soil, and the backfill that is free from materials that could damage the pipe or its coating.

Tab 20

- **Purge pipeline in accordance with P-192.629**
- **Scheduled emissions (purging) require you to fill out the Field Emissions Report within this tab and submit to the Compliance Department prior to the purge**
- **Responsible Party: Manager or Manager Designee**

Purge Procedure Steps

Note: The following precautions should be taken while conducting this procedure:

Safety precautions should be observed during the purging operations. These precautions should include, but not limited to:

1. Prohibit smoking and open flames in the area
2. Prohibit operation of spark producing equipment such as internal combustion engines, electric motors or switches, etc
3. In the event the facilities being purged are straight forward without multiple laterals or looping systems that includes only one upstream valve or isolation device and one downstream valve or isolation device with an existing blowdown valve, step 4 does not have to be completed.
4. In the event the purging process is for new construction and/or includes multiple laterals or loop lines, a written purge plan must be developed, approved by District Manager and followed during the purge process. Within the written purge plan, careful consideration must be given to the following:
    a. Completely purging of extremities of all segments/laterals
    b. Purge process of any piping "loops" within the system which has the potential of air being reintroduced into the main body of the pipeline system.
    c. When tying in a poly system and there is not a permanent vent valve:
        i. There must be a safe method to isolate the blowdown process (i.e., temporary manual valve installed or a set of poly squeezers a safe distance from the purge point)
        ii. Purge point must be located outside of bell hole, be completely vertical and secured to the ground to prevent movement.
5. (If Necessary) Post warning signs and/or barricade area to control public access
6. Purge only thru a vent stack that is at least 6 feet above ground, with secured fittings
7. Each venting areas must be supervised by qualified company employees during purging
8. Provide a fire extinguisher of appropriate type and size at the purging area

Precautions should also be taken to prevent static electrical sparks from igniting escaping gas vapors on plastic pipe.

NOTE: When the pipeline is being purged of air using natural gas, the gas must be released into the pipeline at a moderately rapid and continuous flow. If the gas cannot be supplied in enough quantity to prevent the formation of a hazardous mixture of gas and air, a slug of inert gas must be placed into the line before the gas. The same is true of air being used to purge gas from the pipeline.

1. Conduct a tailgate meeting prior to purging the pipeline. Discuss the following:
    a) Blowdown and purging safety and possible hazards
    b) Location of personnel involved and their duties
    c) Description, use, and location of each piece of work equipment
    d) Flow of the purge gas
    e) Location of firefighting equipment
    f) Pressure of the gas used to purge the pipeline
    g) Time required
    h) Method to check air/gas mixture concentration
    i) Sequence of valve operations
    j) Presence of liquids or other special conditions
    k) Use of personal protective equipment
2. Determine the blow off size, pipeline size, and length of section to be purged
3. Determine the inlet control pressure (see table below)
4. Calculate the purging time period (2 minutes per mile)
5. Before purging is completed, a 100% combustible gas must be achieved and verified with a CGI
6. Install a pressure gauge at the inlet of the section to be purged
7. Have local law enforcement control traffic as necessary
8. Establish communications with all personnel involved in purging of the pipeline
9. Open the blow off valve at the downstream end of the section to be purged
10. Inject inert gas into the inlet end of the pipeline to rapidly displace at least 2 miles of pipe, if necessary in order to prevent a hazardous mixture of gas and air
11. Open the inlet valve far enough to quickly obtain the determined control pressure and maintain this pressure for the necessary purging time
12. At the end of the purging time, close the inlet gas flow valve and continue to vent through the downstream blow off valve for an additional minute per mile of pipe being purged
13. Close the downstream blow off valve

14. Open the inlet valve and slowly bring the pipeline to operating pressure
15. Ensure all valves on the system are open to the proper operating position

Minimum Purge Gas Control Pressure (PSIG) Required for a 2 Minute/Mile Purge Rate

PIPELINE LENGTH	2" B/OFF VALVE Inlet Pressure (psig)		4" BLOWOFF VALVE Inlet Pressure (psig)				6" BLOWOFF VALVE Inlet Pressure (psig)					
(MILE)	4" Pipe	6" Pipe	6" Pipe	8"Pipe	10" Pipe	12" Pipe	12" Pipe	16" Pipe	18" Pipe	20" Pipe	22" Pipe	24" Pipe
1	6	9	3	3	3	5	2	3	4	5	8	12
2	12	13	7	5	5	7	3	4	5	6	8	12
3	18	17	10	7	7	8	5	5	5	7	9	13
4	24	21	13	10	9	10	6	6	6	8	10	14
5	32	25	16	12	11	11	7	7	7	8	11	15
6	40	30	20	14	12	13	9	8	8	9	12	15
7	49	35	24	17	14	14	10	9	9	10	12	16
8	59	41	28	20	16	16	11	10	10	11	13	17
9	71	46	33	22	18	18	13	11	11	12	14	18
10	83	52	38	25	20	19	14	12	12	13	15	19
11	97	59	43	28	22	21	16	13	13	14	16	20
12		66	48	31	25	23	17	14	14	15	17	20
13		73	54	35	27	25	19	15	15	15	17	21
14		81	60	38	29	27	21	16	16	16	18	22
15		90	67	42	32	29	22	18	17	17	19	23
20				63	45	40	31	24	22	22	24	28
25				90	62	52	42	31	28	28	29	33
30					81	66	54	39	35	33	34	38
35						82	68	47	42	40	40	44
40							84	57	50	46	46	50
45								67	58	54	53	56
50								79	67	61	60	63

PIPELINE LENGTH	8" BLOWOFF VALVE Inlet Pressure (psig)			10" BLOWOFF VALVE Inlet Pressure (psig)			12" BLOWOFF VALVE Inlet Pressure (psig)			
(MILE)	20" Pipe	22" Pipe	24" Pipe	24" Pipe	26" Pipe	30" Pipe	34" Pipe	36" Pipe	42" Pipe	48:" Pipe
1	2	3	3	2	2	3	2	3	6	10
2	3	3	4	2	3	3	3	3	6	11
3	3	4	5	3	3	4	3	4	6	11
4	4	5	5	3	4	5	4	4	6	11
5	5	5	6	4	4	5	4	4	7	12
6	6	6	6	5	5	5	4	5	7	12
7	7	7	7	5	5	6	5	5	7	12
8	7	7	8	6	6	6	5	6	8	12
9	8	8	8	6	6	7	6	6	8	13
10	9	9	9	7	7	7	6	6	8	13
11	10	9	10	8	7	8	6	7	9	13
12	10	10	10	8	8	8	7	7	9	14
13	11	11	11	9	9	9	7	7	9	14
14	12	12	12	9	9	9	8	8	10	14
15	13	12	12	10	10	10	8	8	10	15
20	17	16	16	13	13	12	10	10	12	16
25	22	20	19	17	16	15	12	12	14	18
30	27	24	23	20	19	17	14	14	15	20
35	32	29	27	24	22	20	17	16	17	22
40	38	34	32	28	26	23	19	18	19	24
45	44	39	36	32	29	26	21	21	21	25
50	51	45	41	37	33	29	24	23	23	27

Notes:

(1) Purge pressures that exceed 100 psig are not shown in the table. Possible detonation of flammable gases could create unsafe pipeline pressures. Longer purge times (greater that 2 min/mile) and lower purge pressures should be used. See Figure 5-3 for geometry and operating conditions used to calculate the purge pressures in Table 5-1.

(2) Add 5 psig to the pressures shown in Table 5-1, if purging is done through a crossover arrangement and the pressure is measured at the crossover valve. Example: A 30" pipe, 13 miles long, is to be placed into service. A 10" blowdown is to be used for venting. A fifty percent safety factor is selected. Table 5-1 shows that 30" pipe, 13 miles long, requires a natural gas inlet pressure of 9 psig. The length of time is 13 miles times 2 minutes per mile or 26 minutes. After 26 minutes have elapsed, the venting continues for an additional 13 minutes more. Then the blowoff valve is closed.

Source: AGA Purging Principles and Practice Third Edition 2001

Blowdown Procedure/Safety Precautions

The following Safety precautions should be taken while conducting this blowdown procedure including, but are not limited to:

1) Proper PPE
2) Prohibit smoking and open flames in area
3) Prohibit operation of spark producing equipment such as internal combustion engines, electric motors, or switches, cell phones, or other ignition sources
4) (If Necessary) Post warning signs and/or barricade area to prevent public access
5) Purge only through a vent stack that is at least 6 feet above ground level with secured fittings
6) Each venting area must be supervised by qualified company employees during blowdown.

Precautions should also be taken to prevent static electrical sparks from igniting escaping gas vapors on plastic pipe

Blowdown Procedure Steps

1) Conduct tailgate meeting prior to blowing down the pipeline. Discuss the following, but not limited to:
   a) Blowdown safety and possible hazards
   b) Location of personnel and their duties
   c) Description, use, and location of each piece of work equipment
   d) Where blowdown will occur
   e) When electrical high lines are an issue, it is recommended that a liquids truck be used with a long enough high pressure hose to safely vent gas away from electrical lines or an anchored directional fitting (non threaded)
   f) Sequence of valve operations
   g) Presence of liquids or other special conditions
   h) Use of proper personal protective equipment
   i) Continuous monitoring of weather conditions such as (wind direction, thunder storms, etc.) and its effects concerning surrounding facilities for possible ignition sources
   j) A review of the impact on facilities and customers (including points of receipts, delivery and farm taps) including both upstream and downstream. Affected customers shall be notified prior to work being started
2) Install a gauge at various locations to determine complete system blowdown. Ensure gauge is working properly prior to installation

3) Secure necessary local permits and have local law enforcement control traffic as necessary
4) Establish communications with all personnel involved in blowdown
5) Blowdown stack to be at least 6 feet above ground level
6) Shut in all affected valves
7) Apply WTG's lock-out tag-out procedure
8) Eliminate all potential sources of ignition, such as automobiles, cell phones, two-way radios and all other non-intrinsically safe devices
9) Begin blowdown using a continuous and moderately rapid flow
10) A slug of inert gas may be used to prevent a hazardous mixture of gas and air
11) Upon completion of blowdown allow extra time to insure complete depressurization of segment
12) Check pressure gauges to insure pipeline is completely blown down. Ensure pressure gauges are working properly
13) Use a CGI to determine area safe before introducing an ignition source and continue to check periodically to insure there is no gas build up
14) Monitor gas supply and pressure to remaining facilities that are still in-service (upstream and downstream)

Emission Field Report

District:		**Report Date:**	
County:			
GPS Coordinates Start:			
GPS Coordinates End:			
Event/Activity type:			

Date and time event discovered or scheduled activity started:		
Date and time event or scheduled activity ended:		
Event duration:		**Hours**

Is the gas odorized?		
Pipe size:		**IN**
Pipe pressure:		**PSI**
Pipe flow rate (If unknown, leave blank):		**MCF**
Distance of pipe isolated:		**FT**
Was the gas flared or vented to atmosphere:		
Estimated volume of gas released (If unknown, leave blank):		**MCF**

Cause of emission event or excess opacity event, or reason for scheduled activity:

Tab 21

- **Ensure compliance with P-192.605(b)(5) Start up of Pipelines**
- **Responsible Party: Manager or Manager Designee**

Procedure Steps

Start-up

These procedures can be used on new pipeline installations or those pipelines that have been repaired.

1. If the pipeline has been pressure tested, remove any test medium; prepare the system to be purged of all air by the use of gas. Make sure all vents or valves used in the purging process are equipped with vents at least 6 feet above the ground. If necessary to protect the public, barricade the area, and stop vehicle traffic and other sources of ignition.
2. The flow of purge gas must be of sufficient pressure and volume to ensure a complete exclusion of air. The entire segment of pipeline and related equipment must be purged. (**REVIEW PIPELINE PURGING PROCEDURES IN P-192.629**).
3. After purging is completed, all open valves must be closed to prevent air from re-entering the system.
4. The pipeline and related equipment can now be pressured to the normal operating pressures. The pressurization process must be slow and steady. Pressure indicators must be monitored continuously to make certain that the system is not pressured above the established system MAOP.
5. Once the system is pressured to normal operating pressure, all valves, vents, regulators, etc. Should be checked for normal operations.

Shutdown

1. To begin the shutdown procedure, first close the upstream block valve and any additional pressure sources to stop the flow of gas into the pipeline. This will prevent over pressuring of a pipeline. Isolate the downstream block valve at the other end of the pipeline or segment.
2. If the gas pressure must be vented, precautions must be taken to prevent danger to the public, public property, our employees and our facilities. (**REVIEW PIPELINE PURGING PROCEDURES IN P-192.629).**

Tab 22

- **If facilities are abandoned, document on appropriate form. Either F-192.727 or WTG 1400**
- **Ensure abandonment complies with P-192.727**
- **Responsible Party: Manager, Manager Designee, WTG Inspector, or 3rd Party Inspector**

Procedure Steps

Abandonment

Prepare a step-by-step procedure for each pipeline to be abandoned. These procedures must consider the following:

1. Each pipeline abandoned in place must be disconnected from all sources and supplies of gas, purged of gas, and sealed at the ends.
   a) When the volume of the pipeline is so small there is no potential hazard (less than 10% LEL), the pipeline need not be purged.
   b) Filling with inhibited water is preferred if the line has future utility.
   c) Offshore pipelines abandoned in place must be filed with water or inert materials.
2. Except for service lines, each abandoned pipeline that is not being maintained in accordance with DOT requirements must be disconnected from all input sources, purged with an inert medium and sealed at the ends. Offshore pipelines must be filled with water or inert materials. The pipeline need not be purged when the volume is so small that there is no potential hazard.
3. Whenever service to a customer is discontinued, the operator must comply with one of the following:
   a) The valve that is closed to prevent the flow of gas to the customer must be provided with a locking device or other means designed to prevent the opening of the valve by unauthorized people.
   b) A mechanical device or fitting that will prevent the flow of gas must be installed in the service line or in the meter assembly.
   c) The customer's piping must be physically disconnected from the gas supply and the open pipe ends sealed.
4. If air is used for purging, operator must ensure that after purging a combustible mixture (less than 10% LEL) is not present.
5. Whenever a vault or valve box cover has been abandoned, WTG will do the following:
   a) The vault or valve box cover must be removed or secured in a manner so the vault or valve box cover cannot be opened and/or:
   b) Each abandoned vault or valve box must be filled with a suitable compacted material.
6. Documentation of abandonment using form F-192.727 or equivalent.

Inactivation

An inactivated pipeline is a pipeline that although not currently in use, will be maintained and serviced per 49 CFR Part 192 so the pipeline may be returned to service at a future date. Inactivating a pipeline does not require NPMS submission.

1. Methods to Inactivate Pipeline

a) Isolate the pipeline segment from all gas sources by closing all valves. If accidentally pressuring up the pipeline will cause a safety problem, physically isolate the pipeline from all gas sources.

b) Use either natural gas or inert gas in the pipeline to maintain a pressure of 10 to 20 psig to prevent groundwater from entering the pipe. After the pipeline has been inactivated, take a gauge reading to insure that positive pressure exists.

c) Continue maintaining the pipeline as though it was in service (i.e., continue conducting and documenting all applicable O&M inspections).

2. Returning Inactivate Pipeline to Service

Inactivated pipelines that have been maintained per 49 CFR Part 192 may not be returned to service without Engineering Department review and following the Management of Change (MOC) process.

3. Reactivating Pipeline

Resolve any questions concerning safely operating the previously inactivated pipeline and appurtenances before reconnecting the pipeline to a gas source or installing a weld end cap. Verify that all isolation devices including pipes, valves and fittings are removed and that all pipe, valves, fittings, etc. that were installed during the inactivation process meet the design requirements or are removed before reconnecting the pipeline to a gas source or installing a weld end cap.

4. Discontinuing Customer Service

When discontinuing service to a customer, complete one of the following steps to guarantee the gas is stopped and ensure that gas will not accumulate within a building or residence:

a) Lock the block valve or provide another means to prevent an unauthorized person from opening the valve

b) Install a mechanical device that prevents gas flow to the meter or within the service line

c) Physically disconnect the customer's piping from the gas supply and open pipe end seals

5. Documentation

a) Maintain operating, inspecting, testing, maintenance and repair records of each inactivated pipeline for the life of the facility.

b) Maintain records of each pipeline reactivation (e.g., MOC, investigations, test repairs, replacements and alterations, etc.) for the life of the facility.

Company:		District/Location:	
System:		Type of Service	
Description of Facility:			
Location	City:	County:	State:
	Section:	Township:	Range:
Date placed in service:		Date Abandoned:	

Type of abandonment: ☐ In place ☐ Removed

If abandoned in place, describe final disposition of ownership (attach additional pages if necessary).

Purged with:	Filled with:

Describe procedure used to insure that no volatile flammable hydrocarbons remained in the facilities (attach additional pages if necessary):

Completed by:	Date:

Tab 23

- **Complete and submit the Project Report WTG 1400 to the Mapping Department**
- **Responsible Party: Manager or Manager Designee**

Tab 24

- **Written steel welding procedures used during project will be kept in this tab**
- **Copies of the written welding procedures can be obtained by going to the West Texas Gas Website. They are in the WTG Operators Section.**
- **Responsible Party: Manager or Manager Designee**

Procedure Steps

1. Welding Procedures (192.225)
   a) All welding will be performed using qualified procedures or the new procedure will be qualified. All welding procedures will be qualified under section 5 of API 1104 as incorporated by reference in 49 CFR 192.7. The quality of the test welds used to qualify welding procedures shall be determined through destructive testing in accordance with the applicable welding standard(s) In addition, design drawings and specifications for the particular job must be met. The written procedure and all records of qualified testing will be retained for the life of the pipeline.
   b) If the procedure needs to be qualified refer to the Construction Manual: Joining of Pipes by Welding.
   c) No automatic welding equipment is used at this time. Procedure will be created if machine or automatic welding equipment utilized.
2. Welder Qualifications (192.227)
   a) If the pipeline operates at >20% SMYS, annually Welders must be initially qualified in accordance with section 6 of API Standard 1104 20th edition and recognized by PHMSA utilizing WTG specific welding procedures and documenting the qualifications on WTG's Weld Test Report. The second annual test the welder must successfully qualify in accordance with section 6 or section 9 of API Standard 1104 20th edition. These qualification tests cannot exceed 7 ½ months in a calendar year.
   b) If the pipeline will operate at a pressure <20% SMYS, welders may be qualified under Section I of Appendix C of 49 CFR 192.
   c) A welder qualified under an earlier edition than that listed in 49 CFR 192.7 may weld but not re-qualify under that earlier edition.
   d) These records must be maintained for five years following construction.
3. Limitations On Welders (192.229)
   a) If a welder's qualifications were based upon nondestructive testing, he may not weld on compressor station pipe and components.
   b) In order to weld with a welding process, the welder must have within the proceeding 6 months welded using that process.
   c) Welders Qualified under API Standard 1104:
      i) Will not weld on pipe operated at a pressure that produces a hoop stress of 20% or more of SMYS unless within the preceding 6 calendar months that welder has had one weld tested and found acceptable under Sections 6, 9, or Appendix A of API Standard 1104 (See 49 CRF 192.7 for correct edition.)

         NOTE: Welders may maintain an ongoing qualification status by performing welds tested and found acceptable under the above acceptance criteria at least twice each calendar year at intervals not exceeding 7 ½ months.

Tab 25

- **Records of steel welders WTG qualifications/certificates that are associated with this project**
- **This helps to ensure that WTG is in compliance with P-192.225**
- **Responsible Party: Manager, Manager Designee, WTG Inspector, or 3rd Party Inspector**

Procedure Steps

1. Welding Procedures (192.225)

   a) All welding will be performed using qualified procedures or the new procedure will be qualified. All welding procedures will be qualified under section 5 of API 1104 as incorporated by reference in 49 CFR 192.7. The quality of the test welds used to qualify welding procedures shall be determined through destructive testing in accordance with the applicable welding standard(s) In addition, design drawings and specifications for the particular job must be met. The written procedure and all records of qualified testing will be retained for the life of the pipeline.

   b) If the procedure needs to be qualified refer to the Construction Manual: Joining of Pipes by Welding.

   c) No automatic welding equipment is used at this time. Procedure will be created if machine or automatic welding equipment utilized.

2. Welder Qualifications (192.227)

   a) If the pipeline operates at >20% SMYS, annually Welders must be initially qualified in accordance with section 6 of API Standard 1104 20th edition and recognized by PHMSA utilizing WTG specific welding procedures and documenting the qualifications on WTG's Weld Test Report. The second annual test the welder must successfully qualify in accordance with section 6 or section 9 of API Standard 1104 20th edition. These qualification tests cannot exceed 7 ½ months in a calendar year.

   b) If the pipeline will operate at a pressure <20% SMYS, welders may be qualified under Section I of Appendix C of 49 CFR 192.

   c) A welder qualified under an earlier edition than that listed in 49 CFR 192.7 may weld but not re-qualify under that earlier edition.

   d) These records must be maintained for five years following construction.

3. Limitations On Welders (192.229)

   a) If a welder's qualifications were based upon nondestructive testing, he may not weld on compressor station pipe and components.

   b) In order to weld with a welding process, the welder must have within the proceeding 6 months welded using that process.

   c) Welders Qualified under API Standard 1104:

      i) Will not weld on pipe operated at a pressure that produces a hoop stress of 20% or more of SMYS unless within the preceding 6 calendar months that welder has had one weld tested and found acceptable under Sections 6, 9, or Appendix A of API Standard 1104 (See 49 CRF 192.7 for correct edition.)

      NOTE: Welders may maintain an ongoing qualification status by performing welds tested and found acceptable under the above acceptance criteria at least twice each calendar year at intervals not exceeding 7 ½ months.

   ii) May not weld on pipe that will be operated at a pressure producing a hoop stress of less than 20% of SMYS unless the welder is tested according to "i" above or re-qualifies according to d(i) or d(ii) below.

d) A welder qualified under 49 CFR Appendix C may not weld unless –

   i) Within the preceding 15 months, but at least once each calendar year, he is requalified under Appendix C; or

   ii) Within the preceding 7 ½ months, but at least twice each calendar year, he has had:

      (1) A production weld cut out, tested and found acceptable in accordance with the qualifying test; or

      (2) If he will weld only on service lines 2 inches or smaller in diameter, has had two sample welds tested and found acceptable in accordance with the test in section III of 49 CFR 192 Appendix C.

4. Protection From Weather (192.231)

   a) Welding must be protected from weather conditions that would impair the quality of the completed weld.

5. Miter Joints (192.233)

   a) A mitered joint on steel pipe that will be operated at a pressure that produces a hoop stress of 30% or more of SMYS may not deflect the pipe more than 3 degrees.

   b) A miter joint on steel pipe that will be operated at a pressure that produces a hoop stress of less than 30%, but more than 10%, of SMYS may not deflect the pipe more than 12½ degrees and must be a distance equal to one pipe diameter or more away from any other miter joint, as measured from the crotch of each joint.

   c) A miter joint on steel pipe that will be operated at a pressure that produces a hoop stress of 10% or less of SMYS may not deflect the pipe more than 90 degrees.

6. Preparation For Welding (192.235)

   a) Before beginning to weld, ensure the weld surface is clean and free of any material that may be detrimental to the weld, and the pipe or component is aligned in a way that provides the most favorable condition for depositing the root bead.

   b) Ensure that the alignment is preserved while the root bead is being deposited.

7. Inspection Of Welds(192.241)

   a) Refer to procedure P-192.241 for details on performing visual inspection of welds.

   b) Visual inspection is to be conducted by an individual qualified by appropriate training and experience. The inspection is to ensure that the weld is performed according to the written procedure and that the weld is acceptable under d below.

   c) If the pipeline is to be operated at a pressure that produces a hoop stress of 20% or more of SMYS the weld must be nondestructively tested in accordance with procedure P-192.243. However, welds on pipe with a nominal diameter of less than 6 inches do not have to be nondestructively tested if they have been inspected and approved by a qualified

WTG

Tab 26

- **Individuals performing X-Ray inspections must be certified**
- **Keep X-Ray Techs certifications in this tab**
- **Make sure that their Vision Acuity Test is included**
- **Responsible Party: Manager, Manager Designee, WTG Inspector, or 3rd Party Inspector**

Procedure Steps

1. Decide which NDT process to use. The process must clearly indicate defects that may affect the integrity of the weld.

NOTE: Trepanning may not be used. Guidelines for performing each type are located on the following page.

2. Obtain the written procedures for the test. The written procedure must be attached to form F-192.225. If the procedure needs to be qualified, use the appropriate section of F-192.225 to document the qualification. The procedure must have provisions for proper interpretation of the test to ensure the weld is acceptable under 49 CFR 192.241(c) (See procedure P-192.245).
3. Determine that the technicians have been trained on the procedures that are to be used. Document this verification on F-192.225.
4. Witness the results of the test for abnormal conditions or defects.
5. If the weld is found to be unacceptable follow procedure P-192.245 to repair or remove the weld defect.
6. Record all required data on F-192.225. Attach all supplemental data.
7. Retain for the life of the pipeline, a record showing by milepost, engineering station, or by geographic feature, the number of girth welds made, the number nondestructively tested, the number rejected, and the disposition of the rejects. This should be documented on F-192.225.

Radiographic (X-Ray) Inspection

Individuals performing x-ray inspection must be certified. Procedure should be developed according to industry certifications.

Ultrasonic Inspection

1. Prepare pipe surface.
   a) Remove poly coating.
   b) Clean surface.
2. Calibrate UT equipment according to manufacturer's specifications.
3. Use meter to get reading.
   a) UT complete weld area.
   b) Record reading.

NOTE: A detailed procedure that includes test result interpretation must be written and qualified prior to usage.

Magnetic Flux Inspection

Individuals performing magnetic flux inspection must be certified. Procedure should be developed according to industry certifications.

Tab 27

- **Newly installed steel pipelines will need to be protected by a Cathodic Protection System that is in accordance with P-192.455**
- **Ensure that CP Test Stations are installed in accordance with P-192.469**
- **Document the Cathodic Protection System using F-192.455 and keep in this tab**
- **Responsible Party: Manager or Manager Designee**

Description	To describe the installation procedure for corrosion control test stations. This will ensure that pipelines under cathodic protection have sufficient test stations or other contact points for electrical measurement to determine adequacy of protection.
Regulatory Applicability	☒ Regulated Transmission Pipelines ☒ Regulated Gathering Pipelines (Type A) ☒ Regulated Gathering Pipelines (Type B) ☒ Regulated Distribution Pipelines
Frequency	As needed. May be required for new construction and/or for existing pipelines that require additional or replacement test stations.
Reference	49 CFR 192.469 *External Corrosion Control: Test Stations* 49 CFR 192.471 *External Corrosion Control: Test Leads* LA Title 43 Part XIII 2121 *External Corrosion Control: Test Stations* LA Title 43 Part XIII 2123 *External Corrosion Control: Test Leads*
Forms / Record Retention	Update maps to show location.
Related Specifications	None
OQ Covered Task	0041 Installation and Maintenance of Mechanical Electrical Connections 0051 *Installation of Exothermic Electrical Connections* (In order to perform the tasks listed above; personnel must be qualified in accordance with West Texas Gas's Operator Qualification program or directly supervised by a qualified individual.)

Procedure Steps

1. Determine location of needed test station. Test leads should be less than 1 mile apart.
   a) Each pipeline must have test stations that are:
      i) Installed at each cased segment of pipeline, public roads, and railroad crossings. Note: Two test leads should be installed on the casing and two leads should be installed on the carrier pipe.
      ii) Installed at each foreign metallic pipeline crossing.
2. Determine how test lead will be attached (Cadweld, thermite welding, magnetic block, brazing, non-acid solder) and follow the appropriate portion of this procedure.
3. Gather all needed permits – hot work, confined space entry.
4. Excavate area around pipe where leads will be attached. Take care not to damage the pipe or any other facilities in the area of excavation. Follow procedure P-192.319.
5. Remove existing coating to attach leads. Clean pipeline carefully in area where attachment will be made.
6. Determine wall thickness (connection cannot be made in an area of thinned pipe).
7. Wrap test leads around pipe and tie in a knot. Ensure that the connection will be mechanically secure and eclectically conductive.
8. Make permanent connection using the appropriate portion of this procedure.
9. Coat test lead wire and pipe connection with an electrical insulating material compatible with the pipe coating and the wire insulation.
10. Prior to backfilling, measure the pipe-to-soil potential to ensure electro-conductivity between the wire and pipe.
11. Backfill without disturbing the test station or wires. Follow procedure P-192.319.
12. Install post or pole that will be the station marker directly above the pipeline. Do not connect the post or pole directly to the pipeline.
13. If more than one pipeline is monitored at this test station, attach permanent labels designating each pipeline to the appropriate station terminals and wires.
14. Add test station number and location to the most recent annual survey and map.
15. Distribute revised maps as required.

Inspect and Verify Test Lead Continuity

1. Have a qualified individual measure structure-to-soil potential.
2. Verify that the reading is within the desired range.
3. Confirm that test leads are installed and terminated properly and that test leads are not damaged.
4. If test lead continuity is not found, identify damage if possible and recommend mitigation actions based on readings and visible condition of the test lead.
5. Document findings in proper format.

Repair Test Lead

1. Identify the test lead damage.
2. Where necessary, make proper notifications to operations prior to working around structure.
3. Repair test lead damage.
4. Verify that test leads function properly and are no longer damaged.
5. Where necessary, make proper notifications to operations that work has been completed.
6. Document actions and readings.

Cadweld Procedure Steps

Cadweld General and Safety Information

1. Only CADWELD manufactured equipment and materials should be used to make CADWELD connections.
   a) Do not connect items except as detailed on mold tag and in the instructions.
   b) Do not use worn or broken equipment that could cause leakage.
   c) Do not alter equipment or material without factory authorization.
   d) Do not substitute for specified CADWELD manufactured equipment and materials.
   e) Failure to comply with the above may result in hazards to the individual, improper connections, or damage to the items being connected.
2. Starting and welding materials are exothermic mixtures and react to produce molten materials with temperatures in excess of 2200° C (4000° F) and a localized release of smoke. These materials are not explosive. Ignition temperatures are in excess of 460° C (860° F) for starting material, and 900° C (1650° F) for welding material.

3. Make connections in accordance with the prescribed welding procedures and in consideration of surrounding conditions and personnel. Refer to ANSI Z-49.1 Safety in Welding and Cutting and your local safety procedures.
   a) Personnel should be properly trained to use this product.
   b) Avoid direct eye contact with flash of light from ignition of starting material.
   c) Avoid breathing concentrations of smoke as it may be hazardous to health.
   d) Avoid contact with hot materials.
   e) Advise nearby personnel of welding operation in the area.
   f) Remove or protect fire hazard in the immediate area.
   g) Do not smoke when handling starting material.
4. Adhering to the recommended welding procedures will minimize risk of burns and fire caused by hot molten material spillage.
   a) Make sure there is proper mold fit and assembly of equipment.
   b) Avoid moisture and decomposable contaminants in mold and materials being welded. Contact of hot molten material with moisture or contaminants may result in spilling of hot material.
   c) Material thickness must be sufficient for the size and type connection being made to prevent melt-through and leakage of hot molten metal.
5. Unusual application or condition may exist that require special considerations.
   a) Provide adequate ventilation where natural air flow is not sufficient to prevent personnel breathing concentrations of smoke.
   b) In case of fire, water or CO2 will aid control of burning containers. Large quantities of water will aid in controlling a fire should the exothermic materials become involved. Water should be applied from a distance.

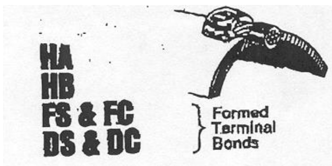
<u>*Preparation*</u>

1. Cable, Ground Rods, and Lugs
   a) Use cable cutters to minimize deforming cable. Burnt or out-of-round cable ends may mold open, causing leaks.
   b) Conductor ends and adjacent length must be clean and dry to insure a good weld.
   c) When using adaptor sleeves, let conductor protrude 1/8” beyond end of sleeve.
2. Steel or Cast Iron Surfaces
   a) Surface must be clean to insure a good weld. Remove any surface protection. Use CADWELD CAT-321 rasp to avoid contaminating welding areas.

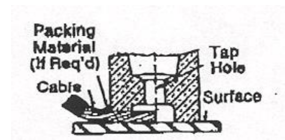
b) Abrade “standard galvanized” surface with emery cloth to remove surface oxides in weld area. Clean “double or triple” galvanized surfaces with rasp to remove galvanizing in weld area.

Welding Procedure

1. Check the following:
   a) Mold is correct for the conductor sizes and application. DO NOT MODIFY MOLDS.
   b) Weld metal indicated on mold tag and steel disks are available. USE ONLY CADWELD WELD METAL.
   c) Frame is attached to mold and adjusted properly.
   d) Flint igniter is in working order.
2. Make sure mold is dry, clean and in good condition. Mold can be dried by heating to about 120° C (250° F).
3. Position mold on conductors following appropriate positioning instructions making a reference mark on conductors at entry point on mold aids in conductor positioning. Check before ignition and for inspection of completed connection.
4. Close mold and lock tightly with handle clamp if split type mold.
5. Use ERICO packing material to pack all openings around conductors at entry point into mold to prevent leaks of molten material, especially where noted on positioning instructions.
6. Insert steel disk, ditched (concave) side up, in crucible to cover tap hole.
7. Pour weld metal into crucible being careful not to upper the steel disk.
8. Tap weld metal container to loosen starting material. Place approximately 1/4 to 1/3 of the starting material on the top lip of the mold at cover opening. Distribute the remaining starting material over the welding material.
9. Close cover.
10. Check reference marks on conductor to verify correct positioning.
11. Stand to side of cover opening and unwind. Aiming flint igniter from the side, ignite starting material on mold lip. Withdraw igniter quickly to prevent fouling.
12. Allow approximately 30 seconds for completion of reaction and solidification of molten material.
13. Open and remove mold. Use care to prevent chipping mold.
14. Clear mold of residue using natural bristle, a soft-cloth, or newspaper before making the next weld. Dispose of residue and weld material package properly. USE CARE TO AVOID BURNS FROM HOT MOLD, CONNECTION, CONDUCTORS OR RESIDUE.

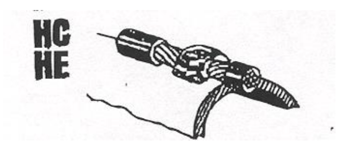


Place mold against surface with end of cable under center of tap hole#1 AWG and larger cables require the use of packing material to seal the mold cable opening. Use the handle or Cat. No CAT-340 Chain Clamp to secure mold to surface.

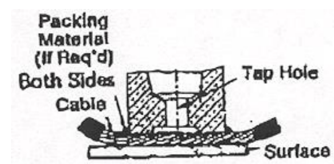


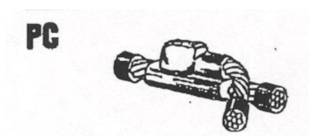
<u>Field Made Formed Terminal Bonds</u>

1. Insert cable thru sleeve with end protruding 1/8”. Place in hammer die, close cover and form with cable protruding as noted.

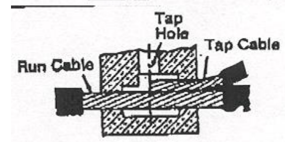


2. Place mold over cable and against surface. Follow “HA” instructions.

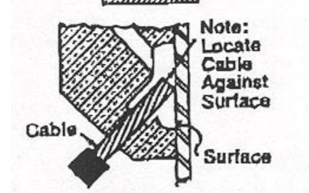


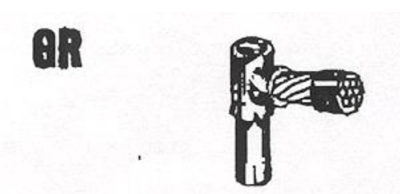


3. Place mold on run cable with end of tap cable under center of tap hole.

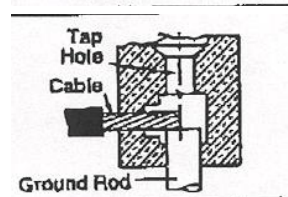


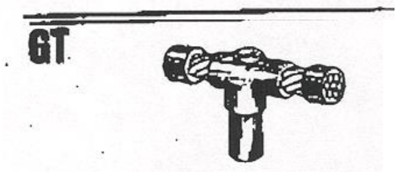
4. Place mold against surface with cable positioned as shown. Secure mold to surface with Cat. No. CAT-339 Chain or with “C” clamp.



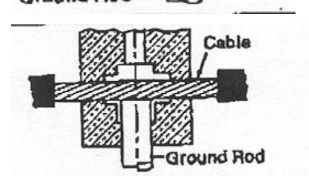


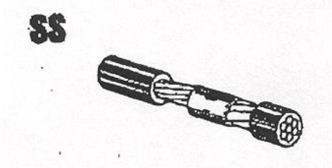
5. Place mold on ground rod with end of cable positioned on top of rod and under center of tap hole. Cable must sit on top of rod as shown.





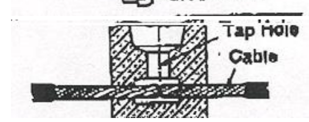
6. Place mold on ground rod with cable positioned across top of rod as shown.





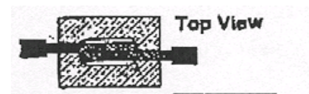
#4 AWG and LARGER

Place mold on cables with ends butting under center of tap hole.

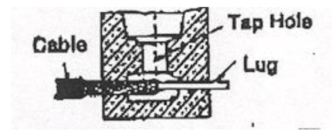


#6 AWG and SMALLER

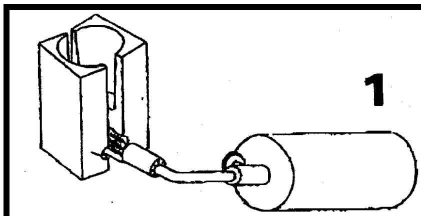
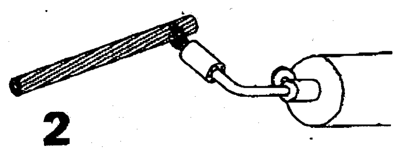
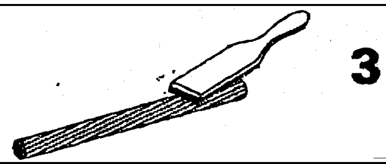
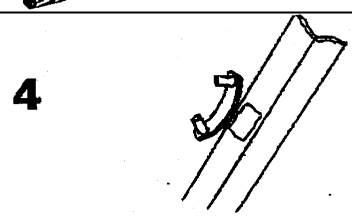
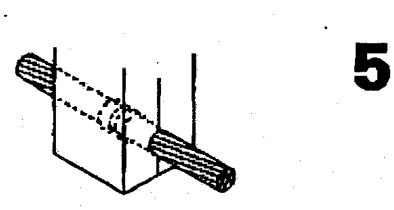
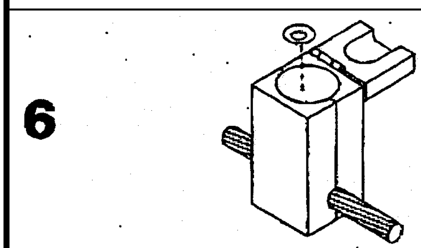
Place mold on overlapped cables and push each cable in until they bottom in weld cavity

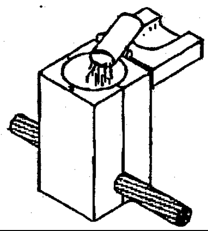
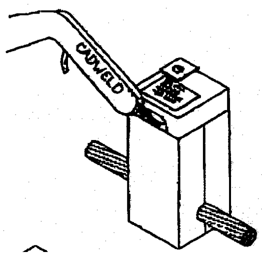
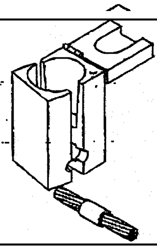
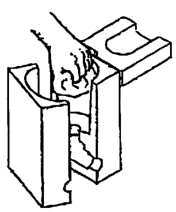
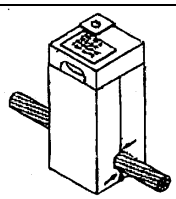


7. Place mold on cable and lug with ends butting under center of tap holes.



Cadweld Condensed Instructions

	Before first connection of the day, dry the mold by heating with a torch.
	Dry conductors to be welded with a torch.
	Clean dried cable ends with a brush to remove dirt and oxides.
	When welding to a steel surface, use a rasp or Erico approved grinding wheel SBS2333 to remove paint, rust and mill scale from area to be welded. (Bright metal showing.)
	Position mold over conduction with conductor ends under center of tap hole. Gap distance, if required, is noted on mold tag. Lock mold handles.
	Insert round metal disk (packaged with weld mold) in bottom of crucible. Make sure it covers tap hole.

 7	Dump in weld material. Sprinkle starting material on mold lip and over weld material.
8 	Close cover. Ignite with spark from flint igniter. Note: Do not use a torch or matches
 9	Wait 10-15 seconds. Open mold and remove from finished connection.
10 	Remove slag and dust with clean rag or mold cleaning tool. Do not use a wire brush. *(An old natural bristle paint brush is ideal.)
 11	Discard mold when excessive leakage occurs around mold openings or if mold disk seat is worn or chipped. Molds are not permanent equipment. They do wear out.

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When to Use This Form

This form is to be used in conjunction with the procedure P-192.455 whenever the cathodic protection system on the pipeline is installed or additional protection is added.

Reviewed Procedures

☐ P-192.455 *Installation of Cathodic Protection System*

The applicable sections of the above procedure(s) shall be reviewed prior to completing this form.

Documentation Procedure

1. Copy form and replace original. Do not mark up the original copy of this form.
2. Gather data and complete the form for each construction project.
3. Attach maps identifying each corrosion test station.
4. Place form in project file.
5. Retain Records for the Life of the Pipeline System.

Cathodic Protection System Installation

Pipeline System:		Segment:	
Drawing References:		Class Location:	
☐New Construction ☐Replacement			
Describe the type of Cathodic Protection Installed			
☐External Coating			
Material:		Application Method:	
☐Anodes			
Date Installed:		Type of anodes:	
Weight of Anodes:		Number of Anodes:	
Spacing:	ft	Depth:	ft
Distance from Structure:	ft	Resistively of soil:	OHM-cm
Estimated current output/anode:	MA	Estimated Replacement Date:	
☐Rectifier			
Complete Cathodic Protection Rectifier and Ground Bed Data portion of this packet.			
☐Map attached showing location of cathodic protection equipment.			
Completed by:		Date:	

Rectifier Installation

This report covers: ☐New installation ☐Addition ☐Replacement		
Rectifier LOC No.	Drawing No.	
Station No.	Mile No.	Land Owner: Tenant:
Size of Easement:	Survey or Section:	
Abstract No:	County:	

Rectifier Data	Type:	Model:	Serial No.	Stack No.
	Mfgr:	Supplier:	Order No.:	
	A.C. Volts:	D.C. Rating: Volts Amps	Initial Readings: Volts Amps	

Groundbed Data	Vertical	No. Rods:	Type:	Size:
		Hole Depth:	Hole Diameter:	Hole Spacing:
	Horiz-ontal	No. Rods	Type:	Size:
		Ditch Depth:	Length & size of scrap pipe:	
	Distance to Line:	Backfill (type and amount):		

Cable Data	Size	Length	Type	Insulation
Ground bed header cable				
Ground bed to rectifier				
Pipe line to rectifier				
Ground rod lead				
CONNECTION: Ground rod lead to header wire				

Power Source:	Meter No.:	Kh:
Rate:	Avg. Monthly Bill:	Installation Cost:
AFE No.:	Installed by (Or contractor):	Date:

Soil Resistivity At Depths	Date	2 1/2’	5’	10’	20’

Approved by:	Date:
Completed by:	Date:

NOTE: Attach sketch of Installation on separate sheet

Tab 28

Photos

WTG

Tab 29

- **Miscellaneous:**___________________________________

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