PIPELINE SAFETY O&M MANUAL CHECKLIST

South Dakota Public Utilities Commission

GENERAL INFORMATION			
Operator Evaluated			
Operator OPID (191.22)			
Unit Description			
Portions of Unit Inspected	O&M Manual and Construction Manual (Does not include Public Awareness, OQ, Control Room Management, Drug and Alcohol Plans, Drug & Alcohol Clinics, Records, Construction, TIMP, or DIMP.)		
Contact Person / Title (person interviewed)		**Email**	
Responsible Party/Title		**Email**	
Mailing Address			
Inspection Date		**Last Inspection Date**	
Location of Inspection			
Inspector Name			

I. Recent Rule Changes		S	N/I	U	N/A
	Recent rules have been incorporated into the appropriate section. **Gathering pipeline requirements are not included in this question set. At this time only Type R gathering lines are identified in South Dakota.**				

II. PART 191 – REPORTING REQUIREMENTS		S	N/I	U	N/A
	Are reporting requirements listed below included in the O&M Manual? 1. Notification of certain incidents (191.5) 2. Report submission requirements (191.7) 3. Distribution system incident report (191.9) (definition of incident in 191.3) 4. Distribution system annual reports (191.11) 5. Transmission and gather system incident report (191.15 (Definition of incident in 191.3) 6. Transmission system annual report (191.17) 7. Notification of changes per 191.22 (c)				

II. PART 191 – REPORTING REQUIREMENTS		S	N/I	U	N/A
	8. Reporting safety related conditions (191.23) revised with Mega Rule implementation 7/1/2020 9. Filling safety – related condition reports revised with Mega Rule implementation 7/1/2020 (191.25) 10. How to notify PHMSA (192.18) revised with Mega Rule implementation 7/1/2020 11. Information provide to NPMS for transmission lines (191.29) 12. Gathering System Annual report (192.8 &191.17)				

III. PART 192 – OPERATION & MAINTENANCE PLANS				S	N/I	U	N/A
§192.605(a)	Is the plan reviewed and updated at intervals not exceeding 15 months but at least once each calendar year?						
	Date of most current review & update	*Date of previous review & update*	*Signatory*				
	List sections of manual that have been significantly updated (i.e. additions/deletions) in the last **2 calendar years**:						
§192.605(a)	Are appropriate parts of the manual kept at locations where operations and maintenance activities are conducted? List locations:						
§192.605(b)(3)	Are construction records, maps, & operating history available to appropriate operating personnel? List locations where and how these records are made available: List operating personnel that have access to these records:						
§192.605(b)(8)	Does the facility have a procedure to periodically review the work done by operator personnel to determine the effectiveness, and adequacy of procedures used in normal operations and maintenance and modify the procedures when deficiencies are found?						
§192.605(b)(9)	Does operator identify procedures for taking adequate precautions in excavated trenches to protect personnel from the hazards of unsafe accumulations of vapor or gas, and making available when needed at the excavation, emergency rescue equipment, including a breathing apparatus and, a rescue harness and line.						
§192.605(c)	**For transmission only operators:** If operating design limits have been exceeded, do the procedures address responding to, investigating, and correcting the cause of: 1. An unintended closure of valves or shutdowns; 2. An increase or decrease in pressure or flow rate outside normal operating limits; 3. A loss of communications; 4. The operation of any safety device; and 5. Any other foreseeable malfunction of a component, deviation from normal operation, or personnel error, which may result in a hazard to						

III. PART 192 – OPERATION & MAINTENANCE PLANS		S	N/I	U	N/A
	persons or property. 7. Provide steps to prevent a recurrence; 8. Document the record keeping process. Does the operator's process includes requirements for checking variations from normal operation after abnormal operation has ended at sufficient critical locations in the system to determine continued integrity and safe operation? 1. Does the operator have personnel assigned to investigate the cause of equipment variations? 2. Is there a root cause plan to determine the cause of equipment variations? Does the operator's process includes requirements for notifying responsible operator personnel when notice of an abnormal operation is received? Does the operator's process includes requirements for periodically reviewing the response of operator personnel to determine the effectiveness of the process controlling abnormal operation and taking corrective action where deficiencies are found? Does the process specify who does the review? Does the process specify how long the reviewer has before submitting recommendations for change? Does the process specify a timetable to implement changes?				
	Has the operator taken appropriate action regarding advisory bulletins published by PHMSA?				
§192.605(d)	Are there instruction on how to recognize a safety related condition?				
§191.23	**Safety Related Conditions** (1) Pipeline 20% or more: Pipe wall thickness reduced to less than that required for MAOP and localized corrosion pitting to a degree where leakage might result. (2) Unintended movement by environmental causes that impairs the serviceability of the pipeline. (3) Pipeline 20% or more: material defect or physical damage that impairs the serviceability (4) Distribution or gathering line: Malfunction or operating error that causes the pressure-plus the margin (build-up) allowed for operations of pressure limiting or control devices – to exceed MAOP (5) A leak in a pipeline that constitutes an emergency. (6) Any safety related condition that could lead to an imminent hazard and causes a 20% or more reduction in operating pressure or shutdown of a pipeline. (7) Transmission: each exceedance of the MAOP that exceeds the margin (build-up) allowed (always required to be reported regardless of time frame)				

III. PART 192 – OPERATION & MAINTENANCE PLANS		S	N/I	U	N/A
	Report is not required if 1) there is an incident report 2) the pipeline is more than 220 yards from any building and not in the ROW 3) is corrected by repair or replacement within 5 working days				
192.13(d)	**Management of Change (Transmission)** Does the operator have a management of change process as outlined in ASME/ANSI B31.8S Section 11? Must be implemented by 2/26/2024 (unless previously required by TIMP plan).				
Section 114	**Identification of Fugitive Emissions** Do procedures provide a methodology for identifying sources of fugitive natural gas emissions in the system?				
Section 114	**Venting** Do procedures identify measures for minimizing natural gas release volumes associated with non-emergency venting and blowdowns from operations and maintenance?				
Section 114	**Investigation of Unanticipated Vented Releases** Do procedures provide for investigation of any unanticipated vented releases of natural gas, and if so, what are the associated actions?				
Section 114	**Leak Data Collection and Analysis** Do procedures include a methodology to collect, retain and analyze detailed information from detected natural gas leaks, including those eliminated by lubrication, adjustment, tightening or otherwise below thresholds for regulatory reporting?				
Section 114	**Detecting Leaks** Do procedures include instructions for personnel to detect leaks to help further reduce emissions in stations and along the right of way?				
Section 114	**Leak Mitigation & Repair** Do procedures define a process to identify, classify, mitigate and repair leaks?				
Section 114 – Distribution	**Lost & Unaccounted for Gas** Do procedures provide for review of Lost & Unaccounted for Gas (LAUF) and do procedures specify actions to reduce the associated volume?				
Section 114 – Distribution	**Regulator Stations – O&M** Do maintenance or operational procedures contain measures for reduction of natural gas releases from regulators?				
Section 114 – Distribution	**Regulator Stations – Configuration** Do maintenance or operational procedures contain measures for identifying potential configuration changes that would reduce natural gas releases from regulators?				
Section 114	**Testing – Relief Valves** Do relief valve testing procedures include measures to minimize natural gas releases?				
Section 114	**Flaring** Do procedures for flaring from pipeline facilities for transporting natural gas include measures for minimization of natural gas emissions?				

III. PART 192 – OPERATION & MAINTENANCE PLANS		S	N/I	U	N/A
Section 114	**Feedback to Design/Configuration Practices** Do operation and maintenance procedures contain mechanisms for identifying potential design/configuration changes for reducing natural gas releases?				
Section 114	**Leak Prone Pipe:** What procedures are in place to monitor for and identify pipe segments that are leak-prone, and what criteria (e.g., frequency of leak or failure events) are specified for determining a pipeline segment is leak-prone?				
Section 114	**Leak Prone Pipe:** Do procedures include a methodology to collect, retain and analyze detailed information from detected leaks, including those eliminated by lubrication, adjustment, tightening or otherwise below thresholds for regulatory reporting?				
Section 114	**Leak Prone Pipe:** Do procedures identify cast iron, unprotected steel, wrought iron, and vintage plastic pipe with known leak issues?				
Section 114	**Leak Prone Pipe:** Do procedures clearly define a process to address replacement or remediation of pipe segments with known leak issues beyond those specifically identified in Section 114?				

IV. PART 192 – EMERGENCY PLANS				S	N/I	U	N/A
§192.615 §192.605(e)	Does the operator have a written emergency plan?						
	Date of most current review & update	*Date of previous review & update*	*Signatory*				
§192.615(a)	Does operator have a written procedures to minimize the hazard resulting from a gas pipeline emergency that includes the following:						
	(1) Receiving, identifying, and classifying notices of events which require immediate response by the operator.						
	(2) Establishing and maintaining adequate means of communication with appropriate fire, police, and other public officials. **Determine the responsibilities, resources, jurisdictional areas and emergency contact telephone numbers for both local and out of area calls for each Federal, State, and local government organizations that may respond to a pipeline emergency and inform such officials about the operator's ability to respond to a pipeline emergency and the means of communication during emergencies.**						
	(3) Prompt and effective response to a notice of each type of emergency, including the following: (i) Gas detected inside or near a building. (ii) Fire located near or directly involving a pipeline facility. (iii) Explosion occurring near or directly involving a pipeline facility. (iv) Natural disaster.						

IV. PART 192 – EMERGENCY PLANS		S	N/I	U	N/A
	(4) The availability of personnel, equipment, tools, and materials, as needed at the scene of an emergency.				
	(5) Actions directed toward protecting people first and then property.				
	(6) Take action - Emergency shutdown and pressure reduction in any section of the operator's pipeline system necessary to minimize hazards to life or property.				
	(7) Making safe any actual or potential hazard to life or property.				
	(8) Notifying appropriate public safety answering point (911) as well as fire, police, and other public officials, of gas pipeline emergencies to coordinate and share information and planned responses as well as actual responses during an emergency. Does the emergency plan define the operator's designated person(s) (e.g., controller or other personnel) responsible to directly notify 911 or the phone number of appropriate local emergency officials to report emergencies and possible pipeline ruptures to first responder agencies/authorities? (NTSB P-11-9)				
	(9) Safely restoring any service outage.				
	(10) Beginning action under §192.617 (failure investigation), if applicable, as soon after the end of the emergency as possible.				
	(11) Actions required to be taken by a controller during an emergency in accordance with § 192.631, 192.634 and 192.636.				
	(12) Develop written rupture identification procedures to evaluate and identify whether a notification of potential rupture is an actual rupture event or a non-rupture event.				
§192.615(a)(3)	Determine whether the procedures adequately address the possibility of multiple leaks and underground migration of gas into nearby buildings. (Refer to 4/12/01 letter from PHMSA in response to NTSB recommendation P-00-20 and P-00-21. (NTSB) Chapter 5.1(89))				
	Has the operator made provisions for:				
§192.615(b)(1)	Furnishing applicable portions of the emergency plan to supervisory personnel who are responsible for emergency action? List of Persons Plan Furnished To:				

IV. PART 192 – EMERGENCY PLANS		S	N/I	U	N/A
§192.615(b)(2)	Is there a requirement to train appropriate employees as to the requirements of the emergency plan. Review training records.				
§192.615(b)(3)	(a) Review activities following actual or simulated emergencies to determine if they are effective. Does facility have the review and its outcome documented within their records? (b) Review records.				
§192.615(c)	Establish mutual liaison with the appropriate public safety answering point (911) as well as fire, police, and other public officials, such that each is aware of the others resources and capabilities in dealing with gas emergencies. Review documentation.				
	(1) Learn the responsibility and resources of each government organization that may respond to a gas pipeline emergency				
	(2) Acquaint the officials with the operator's ability in responding to a gas pipeline emergency				
	(3) Identify the types of gas pipeline emergencies of which the operator notifies the officials				
	(4) Plan how the operator and officials can engage in mutual assistance to minimize hazards to life or property				

V. PART 192 – MISCELLANEOUS		S	N/I	U	N/A
§192.5	**Transmission only:** Class Location - Does the operator have records that document the current class location of each pipeline segment? How was class location determined? revised with Mega Rule implementation 7/1/2020				
§192.7	How are documents incorporated by reference addressed? Are they up-to-date? revised with Mega Rule implementation 7/1/2020				
§192.8(b)	Does the operator have a procedure for documenting the methodology by which it calculated the beginning and end points of each **gathering** line? Review documentation.				

V. PART 192 – MISCELLANEOUS		S	N/I	U	N/A
§192.14	(a) A steel pipeline previously used in service not subject to this part qualifies for use under this part if the operator prepares and follows a written procedure to carry out the following requirements: (1) The design, construction, operation, and maintenance history of the pipeline must be reviewed and, where sufficient historical records are not available, appropriate tests must be performed to determine if the pipeline is in a satisfactory condition for safe operation. (2) The pipeline right-of-way, all aboveground segments of the pipeline, and appropriately selected underground segments must be visually inspected for physical defects and operating conditions which reasonably could be expected to impair the strength or tightness of the pipeline. (3) All known unsafe defects and conditions must be corrected in accordance with this part. (4) The pipeline must be tested in accordance with Subpart J of this part to substantiate the maximum allowable operating pressure permitted by Subpart L of this part. (b) Each operator must keep for the life of the pipeline a record of investigations, tests, repairs, replacements, and alterations made under the requirements of paragraph (a) of this section. (c) An operator converting a pipeline from service not previously covered by this part must notify PHMSA 60 days before the conversion occurs as required by § 191.22 of this chapter.				
§192.59 / 192.193	Plastic pipe - Is the type of plastic pipe and fittings permitted to be used addressed?				
§192.63	Marking of Materials – Are there steps to ensure that only properly marked materials and purchased and installed?				
§192.67	Steel Transmission Only: Does the operator have requirements for collecting and maintaining the for the life of the pipeline, records that document the physical characteristics of the pipeline (diameter, yield strength, ultimate tensile strength, wall thickness, seem type, and chemical composition of materials), tests, inspections, and attributes. revised with Mega Rule implementation 7/1/2020 (Does not apply to Type B gathering)				
§192.69	Does the operator have a written procedure for storage and handling of plastic pipe and associated components?				
§192.121	How is the operator determining if plastic pipe meets the design formula per 192.121? Is this updated with the per new plastic pipe rules? (192.123 has been removed)				
§192.127	Steel Transmission Only: Does the operator require records of pipe design. revised with Mega Rule implementation 7/1/2020 (Does not apply to Type B gathering)				

V. PART 192 – MISCELLANEOUS		S	N/I	U	N/A
§192.143 / 192.145 / 192.147 / 192.149 / 192.204	How is the operator ensuring all components meet the requirements of the code? (plastic components, valves, fittings, risers)				
§192.150	Does the operator require that all new transmission lines are capable of being pigged? revised with Mega Rule implementation 7/1/2020				
§192.205	Steel Transmission Lines: Does the operator require that documentation is retained for all components installed in the pipeline? revised with Mega Rule implementation 7/1/2020 (Does not apply to Type B gathering)				

V. PART 192 – CUSTOMER NOTIFICATION		S	N/I	U	N/A
§192.16	Is there a requirement for the operator to notify all customers by **August 14, 1996** or new customers within **90** days of their responsibility for those sections of service lines not maintained by the operator? Generally doesn't apply to operators in South Dakota.				

VI. PART 192 – WELDING		S	N/I	U	N/A
	General				
§192.225(a)	Is welding performed by a qualified welder in accordance with API 1104, section IX of the ASME Boiler and Pressure Vessel Code, or Appendix C of Part 192? (yes or no) If yes, highlight or specify which method is used.				
API 1104	If using API 1104, does operator maintain records of qualified welders that contains the following information (*it is recommended they use Figure 2 from API 1104*):				
	- Date of welding				
	- Location				
	- Name of welder				
	- Weld position				
	- Welding time				
	- Weather conditions				
	- Voltage				
	- Amperage				
	- Welding machine type				
	- Welding machine size				
	- Filler metal				
	- Reinforcement size				
	- Pipe type and grade				
	- Wall thickness				
	- Outside diameter				
	- Tensile strength information (and any remarks on tensile strength test)				
	- Bend test information (and any remarks on bend test)				
	- Nick-break test information (and any remarks on nick-break test)				

VI. PART 192 – WELDING		S	N/I	U	N/A
	- Date tested				
	- Location of test				
	- Name of tester				
	- Results of qualification test (whether they are qualified or disqualified)				
§192.225(b).	Has each welding procedure been recorded in detail, including the results of the qualifying tests?				
	If using API 1104, does the record include the items in Appendix A of this form?				
	If using ASME Boiler and Pressure Vessel code, does the record include the items in Appendix C of this form?				
	Did the procedures pass all the tests?				
	Does the data on the record conform to the requirements of the welding standard used (1104 or Boiler and Pressure Vessel)?				
§192.231	Does the operator have written specifications that include the assessment of weather conditions that may impact the quality of welding and provisions for suspending and resuming welding operations? 1. Wind: (1) High wind speeds could introduce debris into the weld and blow away shielding gases. (2) High wind speeds could impair the welder's control of the arc. 2. Precipitation: (1) Quenching of the weld by direct precipitation. (2) Residual moisture on the pipe could contribute to hydrogen cracking. 3. Temperature: (1) Extremely cold temperatures can cause problems with heating or maintaining preheat of the pipe or cause preheat temperature to be unattainable.				
§192.227					
§192.227(c)	Steel Transmission Lines: Are welding qualifications required to be kept for a minimum of 5 years after construction? revised with Mega Rule implementation 7/1/2020 (Does not apply to Type B gathering)				
§192.229(b)	Does operator maintain records for each qualified welder that show the welder has engaged in a specific welding process within the last 6 months or had a weld tested within that preceding 7.5 months?				
192.229(c)	(1) For pipelines operating at a pressure that produces a hoop stress of 20% or more of SMYS, does the operator have records that show within the preceding 6 months the welder has had one weld tested and found acceptable under section 6 or 9 of API Standard 1104, *Exception: A welder qualified under an earlier addition may weld but not requalify under that earlier addition.* Alternatively, do welders maintain an ongoing qualification status by performing welds tested and found acceptable under section 6 or 9 of API 1104 at least twice each calendar year, but at intervals not exceeding 7-1/2 months?				

VI. PART 192 – WELDING		S	N/I	U	N/A
	(2) May not weld on pipe to be operated at a pressure less than 20 percent of SMYS unless the welder is tested in accordance with §192.229(c)(1) or requalifies under §192.229(d)(1) or (d)(2).				
192.229(d)	**Low Stress -** For welders that qualify under 192.227(b), does operator maintain records for each qualified welder that show the welder has been requalified within preceding 15 calendar months or within the preceding 7 ½ calendar months (at least twice a year) had one of the following : - a production weld cut out, tested, and found acceptable with the qualifying test; or - for welders that work only on service lines 2 inches or smaller, two sample welds tested and found acceptable in accordance with section III of Appendix C				
§192.233	**Miter Joints** Do written specifications or standards prohibit the use of certain miter joints, as follows? 1. Miter joints on steel pipe to be operated at a pressure that produces a hoop stress of 30 percent or more of SMYS do not deflect the pipe more than 3 degrees. 192.233(a) 2. Miter joints on steel pipe to be operated at a pressure that produces a hoop stress of less than 30 percent, but more than 10 percent of SMYS do not deflect the pipe more than 12.5 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. 192.233(b) 3. Miter joints on steel pipe to be operated at a pressure that produces a hoop stress of 10 percent or less of SMYS do not deflect the pipe more than 90 degrees. 192.233(c) **4.** What document(s) does the operator possess to validate this or these requirements? Request a copy if one is available.				
§192.235	Do written specifications or procedures require the following welding preparations to be performed? 1. Welding surfaces are clean and free of foreign material. 2. Welding surfaces are aligned in accordance with the qualified welding procedure. 3. Alignment must be preserved while the root bead is being deposited. 4. Pipe movement while the root bead is being deposited is not acceptable. 5. Hinging, the practice of depositing a tack weld then moving the pipe to improve joint alignment in other areas, is not acceptable.				
§192.241(a)	Is a visual inspection of the weld conducted to ensure: (1) The welding is performed in accordance with the welding procedure; and (2) The weld is acceptable under paragraph (c) of this section.				

VI. PART 192 – WELDING		S	N/I	U	N/A
§192.241(b)	Is non-destructive testing conducted on pipelines that produce a hoop stress of 20 percent or more of SMYS? (except that welds that are visually inspected and approved by a qualified welding inspector need not be nondestructively tested if pipe is less than 6 inches or welds are so limited in number that nondestructive testing is impractical)				
§192.241(c)	Is a weld that is nondestructively tested or visually inspected determined according to the standards in Section 9 or Appendix A of API Standard 1104? (Appendix A may not be used to accept cracks.)				
§192.243 (a), (b) & (c)	Is there a procedure for nondestructive weld testing? Are non-destructive tests done by person who have been trained and qualified in the procedure and equipment?				
§192.243(d)	When nondestructive testing is required under §192.241(b), are the following percentages of each day's field butt welds, selected at random by the operator, nondestructively tested over their entire circumference?				
§192.243(d) (1)	In Class 1 locations, except offshore, at least 10 percent				
§192.243(d) (2)	In Class 2 locations, at least 15 percent.				
§192.243(d) (3)	In Class 3 and Class 4 locations, at crossings of major or navigable rivers, offshore, and within railroad or public highway rights-of-way, including tunnels, bridges, and overhead road crossings, 100 percent unless impracticable, in which case at least 90 percent. Nondestructive testing must be impracticable for each girth weld not tested.				
§192.243(f)	Are records showing by milepost, engineering station, or geographic feature, the number of girth welds made, the number tested, the number rejected, and the disposition of the rejects retained for the life of the pipeline?				

VII. PART 192 – REPAIR OR REMOVAL OF WELD DEFECTS		S	N/I	U	N/A
§192.245	(a) Each weld that is unacceptable under §192.241(c) must be removed or repaired. (b) Each weld that is repaired must have the defect removed down to sound metal and the segment to be repaired must be preheated if conditions exist which would adversely affect the quality of the weld repair. After repair, the segment of the weld that was repaired must be inspected to ensure its acceptability. (c) Repair of a crack, or of any defect in a previously repaired area must be in accordance with written weld repair procedures that have been qualified under §192.225. Repair procedures must provide that the minimum mechanical properties specified for the welding procedure used to make the original weld are met upon completion of the final weld repair.				

VIII. PART 192 – JOINING OF PIPELINE MATERIALS OTHER THAN BY WELDING		S	N/I	U	N/A
	The operator has the following material types in their system: steel, plastic, cast iron, ductile iron, copper				
	What types of joining does the operator perform (i.e. plastic fusion, mechanical joints, electrofusion, threaded fittings, plastic adhesives)? List out all types of joining used.				
§192.273	Do the procedures require the following? (a) The pipeline must be designed and installed so that each joint will sustain the longitudinal pullout or thrust forces caused by contraction or expansion of the piping or by anticipated external or internal loading. (b) Each joint must be made in accordance with written procedures that have been proved by test or experience to produce strong gas-tight joints. (c) Each joint must be inspected to insure compliance with this subpart.				
§192.281(a)	A plastic pipe joint that is joined by solvent cement, adhesive, or heat fusion may not be disturbed until it has properly set. Plastic pipe may not be joined by a threaded joint or miter joint.				
§192.281(b)	Each solvent cement joint on plastic pipe must comply with the following: (1) The mating surfaces of the joint must be clean, dry, and free of material which might be detrimental to the joint; (2) The solvent cement must conform to ASTM Designation: D 2513; (3) The joint may not be heated to accelerate the setting of the cement. **Solvent cement is not used as a joining process in SD.**				x
§192.281(c)	Each heat-fusion joint on plastic pipe must be made according to F2620 or equivalent procedure and comply with the following:				
	(1) A butt heat-fusion joint must be joined by a device that holds the heater element square to the ends of the pipe or component, compresses the heated ends together, and holds the pipe in proper alignment in accordance with the appropriate procedure qualified under § 192.283.				
	(2) A socket heat-fusion joint must be joined by a device that heats the mating surfaces of the pipe or component, uniformly and simultaneously, to establish the same temperature. The device used must be the same device specified in the operator's joining procedure for socket fusion.				

VIII. PART 192 – JOINING OF PIPELINE MATERIALS OTHER THAN BY WELDING		S	N/I	U	N/A
	(3) An electrofusion joint must be made using the equipment and techniques prescribed by the fitting manufacturer, or using equipment and techniques shown, by testing joints to the requirements of § 192.283(a)(1)(iii), to be equivalent to or better than the requirements of the fitting manufacturer.				
	(4) Heat may not be applied with a torch or other open flame.				
§192.281(d)	Each adhesive joint on plastic pipe must comply with the following: (1) The adhesive must conform to ASTM D 2517 (incorporated by reference, see §192.7), (2) The materials and adhesive must be compatible with each other. **Adhesive is not used as a joining process in SD.**				x
§192.281(e)	Each compression type mechanical joint on plastic pipe must comply with the following: (1) The gasket material in the coupling must be compatible with the plastic, (2) A rigid internal tubular stiffener, other than a split tubular stiffener, must be used in conjunction with the coupling. (3) All mechanical fittings must meet a listed specification based upon the applicable material. (4) All mechanical joints or fittings installed after January 22, 2019, must be Category 1 as defined by a listed specification for the applicable material, providing a seal plus resistance to a force on the pipe joint equal to or greater than that which will cause no less than 25% elongation of pipe, or the pipe fails outside the joint area if tested in accordance with the applicable standard.				
§192.283	**Plastic Pipe**				
	Does operator have written procedures for each type of joint available for review? (yes or no)				
	Do these procedures follow what is required by the manufacturer? Has the operator changed any parameters? (yes or no)				

VIII. PART 192 – JOINING OF PIPELINE MATERIALS OTHER THAN BY WELDING		S	N/I	U	N/A
	Does operator have copies of the destructive tests used to qualify the joining procedures? (yes or no) (a) Heat fusion, solvent cement, and adhesive joints. Before any written procedure established under § 192.273(b) is used for making *plastic pipe joints* by a heat fusion, solvent cement, or adhesive method, the procedure must be qualified by subjecting specimen joints that are made according to the procedure to the following tests, as applicable: (1) The test requirements of-- (i) In the case of *thermoplastic* pipe, based on the pipe material, the Sustained Pressure Test or the Minimum Hydrostatic Burst Test per the listed specification requirements. Additionally, for electrofusion joints, based on the pipe material, the Tensile Strength Test or the Joint Integrity Test per the listed specification. (ii) In the case of thermosetting plastic pipe, paragraph 8.5 (Minimum Hydrostatic Burst Pressure) or paragraph 8.9 (Sustained Static Pressure Test) of ASTM D2517- 00 (incorporated by reference, see § 192.7). (iii) In the case of electrofusion fittings for polyethylene (PE) pipe and tubing, paragraph 9.1 (Minimum Hydraulic Burst Pressure Test), paragraph 9.2 (Sustained Pressure Test), paragraph 9.3 (Tensile Strength Test), or paragraph 9.4 (Joint Integrity Tests) of ASTM F1055-98(2006) (incorporated by reference, see § 192.7). (2) For procedures intended for lateral pipe connections, subject a specimen joint made from pipe sections joined at right angles according to the procedure to a force on the lateral pipe until failure occurs in the specimen. If failure initiates outside the joint area, the procedure qualifies for use. (3) For procedures intended for non-lateral pipe connections, perform testing in accordance with a listed specification. If the test specimen elongates no more than 25% or failure initiates outside the joint area, the procedure qualifies for use. (b) Mechanical joints. Before any written procedure established under § 192.273(b) is used for making mechanical plastic pipe joints, the procedure must be qualified in accordance with a listed specification based upon the pipe material.				
	(c) A copy of each written procedure being used for joining plastic pipe must be available to the persons making and inspecting joints.				
	Plastic Pipe				

VIII. PART 192 – JOINING OF PIPELINE MATERIALS OTHER THAN BY WELDING		S	N/I	U	N/A
§192.285(a)(1) §192.285(a)(2) and §192.285(c)	Does operator have a procedure for qualifying individual on pipe joining and maintain records of employee training dates and type of joint training for each employee? Procedure must require that the joint is visually inspected and tested for failure.				
§192.285(e)	For plastic transmission pipe: Are records required to be kept for a minimum of 5 years after construction? revised with Mega Rule implementation 7/1/2020 (Does not apply to Type B gathering)				
§192.287	Is each person that inspects joints in plastic pipe qualified by appropriate training or experience in evaluating the acceptability of plastic pipe joints?				
§192.756	**Joining plastic pipe by heat fusion; equipment maintenance and calibration.** Each operator must maintain equipment used in joining *plastic pipe* in accordance with the manufacturer's recommended practices or with written procedures that have been proven by test and experience to produce acceptable joints.				
§192.281 (e)	**Threaded Joints** Does the operator have a procedure for using threaded joints and mechanical joints and is it included in the OQ plan? Mechanical Joints				

IX. PART 192 – INSPECTION AND REPAIR OF MATERIALS		S	N/I	U	N/A
§192.307	Each length of pipe and each other component must be visually inspected at the site of installation to ensure that it has not sustained any visually determinable damage that could impair its serviceability				
§192.309	Repair of steel pipe.				
	(a) Each imperfection or damage that impairs the serviceability of a length of pipeline of steel pipe must be repaired or removed. If a repair is made by grinding, the remaining wall thickness must a least be equal to either: (1) The minimum thickness required by the tolerances in the specification to which the pipe was manufactured; or (2) the design pressure of the pipeline.				

IX. PART 192 – INSPECTION AND REPAIR OF MATERIALS		S	N/I	U	N/A
	Each of the following dents must be removed from steel pipe to be operated at a pressure that produces a hoop stress of 20 percent, or more, of SMYS, unless the dent is repaired by a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe: (1) A dent that contains a stress concentrator such as a scratch, gouge, groove, or arc burn. (2) A dent that affects the longitudinal weld or a circumferential weld. (3) In pipe to be operated at a pressure that produces a hoop stress of 40 percent or more of SMYS, a dent that has a depth of: (i) More than ¼ inch (6.4 millimeters) in pipe 12¾ inches (324 millimeters) or less in outer diameter; or (ii) More than 2 percent of the nominal pipe diameter in pipe over 12 3/4 inches (324 millimeters) For the purpose of this section a "dent" is a depression that produces a gross disturbance in the curvature of the pipe wall without reducing the pipe-wall thickness. The depth of a dent is measured as the gap between the lowest point of the dent and a prolongation of the original contour of the pipe.				
	Each arc burn on steel pipe to be operated at a pressure that produces a hoop stress of 40 percent or more, of SMYS must be repaired or removed. If a repair is made by grinding, the arc burn must be completely removed and the remaining wall thickness must be at least equal to either: (1) The minimum wall thickness required by the tolerances in the specification to which the pipe was manufactured; or (2) The nominal wall thickness required for the design pressure of the pipeline. (d) A gouge, groove, arc burn, or dent may not be repaired by insert patching or by pounding out. (e) Each gouge, groove, arc burn, or dent that is removed from a length of pipe must be removed by cutting out the damaged portion as a cylinder.				
§192.311	Repair of Plastic Pipe: Each imperfection or damage that would impair the serviceability of plastic pipe must be repaired or removed.				

X. PART 192 – EXCESS FLOW VALVES		S	N/I	U	N/A
§192.381(a)	Are excess flow valves (that operate at $\geq$ 10 psi) manufactured and tested to an industry standard or manufacturer's written specification to ensure each valve will:				

X. PART 192 – EXCESS FLOW VALVES		S	N/I	U	N/A
§192.381(a)(1)	Function properly up to the MAOP at which valve is rated;				
§192.381(a)(2)	Function properly at all temperatures reasonably expected in the operating environment of the service line;				
§192.381(a)(3)	(i) at 10 psi gage – close at $\leq$ 50 % above the rated closure flow specified by manufacturer; AND				
§192.381(a)(3)	upon closure, reduce gas flow to: (ii)(A) no more than 5% of manufacturer's specified closure flow rate for an EFV designed to allow pressure to equalize across the valve (up to a maximum of 20 ft^3/hr) – OR – (ii)(B) no more than 0.4 ft^3/hr for an EFV designed to prevent equalization of pressure across the valve; AND				
§192.381(a)(4)	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?				
§192.381(c)	Does the operator must mark or otherwise identify the presence of an excess flow valve on the service line?				
§192.381(d)	Does the operator locate the EFV as near as practical to the fitting connecting the service line to its source of gas supply?				
§192.381(e)	An operator should not install an excess flow valve on a service line where the operator has prior experience with contaminants in the gas stream, where these contaminants could be expected to cause the excess flow valve to malfunction or where the excess flow valve would interfere with necessary operation and maintenance activities on the service, such as blowing liquids from the line.				
§192.383(b)	After April 14, 2017, each operator must install an EFV on any new or replaced service line serving the following types of services before the line is activated: (1) A single service line to one SFR; (2) 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); (3) A branched service line to a SFR installed off a previously installed SFR service line that does not contain an EFV; (4) Multifamily residences with known customer loads not exceeding 1,000 SCFH per service, at time of service installation based on installed meter capacity, and (5) 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.				

X. PART 192 – EXCESS FLOW VALVES		S	N/I	U	N/A
§192.383(c)	Exceptions to excess flow valve installation requirement. An operator need not install an excess flow valve if one or more of the following conditions are present: (1) The service line does not operate at a pressure [(expressed in pounds per square inch above atmospheric pressure, i.e., gage, pressure (abbreviation psig), unless otherwise stated). See Maximum allowable test pressure, Overpressure protection, Pressure limiting station, Pressure regulating station, Pressure relief station, Standup pressure test. (Guide definition)] of 10 psig or greater throughout the year; (2) 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; (3) An EFV could interfere with necessary operation or maintenance activities, such as blowing liquids from the line; or (4) An EFV meeting the performance standards in § 192.381 is not commercially available to the operator.				
	Does the operator mark or otherwise identify the presence of an excess flow valve on a service line?				
192.383(d)	Customer's right to request an EFV. Existing service line customers who desire an EFV on service lines not exceeding 1,000 SCFH and who do not qualify for one of the exceptions in paragraph (c) of this section may request an EFV to be installed on their service lines. If an eligible service line customer requests an EFV installation, an operator must install the EFV at a mutually agreeable date. The operator's rate-setter determines how and to whom the costs of the requested EFVs are distributed.				

X. PART 192 – EXCESS FLOW VALVES		S	N/I	U	N/A
§192.383 (e)	Operator notification of customers concerning EFV installation. Operators must notify customers of their right to request an EFV in the following manner: (1) Except as specified in paragraphs (c) and (e)(5) of this section, each operator must provide written or electronic notification to customers of their right to request the installation of an EFV. Electronic notification can include emails, Web site postings, and e- billing notices. (2) The notification must include an explanation for the service line customer of the potential safety benefits that may be derived from installing an EFV. The explanation must include information that an EFV is designed to shut off the flow of natural gas automatically if the service line breaks. (3) The notification must include a description of EFV installation and replacement costs. The notice must alert the customer that the costs for maintaining and replacing an EFV may later be incurred, and what those costs will be to the extent known. (4) The notification must indicate that if a service line customer requests installation of an EFV and the load does not exceed 1,000 SCFH and the conditions of paragraph (c) are not present, the operator must install an EFV at a mutually agreeable date. (5) Operators of master-meter systems and liquefied petroleum gas (LPG) operators with fewer than 100 customers may continuously post a general notification in a prominent location frequented by customers. (f) Operator evidence of customer notification. An operator must make a copy of the notice or notices currently in use available during PHMSA inspections or State inspections conducted under a pipeline safety program certified or approved by PHMSA under 49 U.S.C. 60105 or 60106.				
§192.383 (f)	(f) Operator evidence of customer notification. An operator must make a copy of the notice or notices currently in use available during PHMSA inspections or State inspections conducted under a pipeline safety program certified or approved by PHMSA under 49 U.S.C. 60105 or 60106.				
§192.385(b)	Does the operator install a curb valve when no EFV is available?				
§192.385(c)	Has the operator identified a periodic maintenance procedure for curb valves?				

XI. PART 192 – CORROSION GENERAL		S	N/I	U	N/A
§192.605(b)(2) §192.453	(a) Are corrosion control procedures established?				
	(b) Are there procedures for: Design				
	Installation				
	Operation				
	Maintenance				
	(c) Are these procedures under the responsibility of a qualified person?				

XII. PART 192 – EXTERNAL CORROSION CONTROL		S	N/I	U	N/A
§192.455(a)	**For pipelines installed after July 31, 1971:** Are buried segments externally coated & cathodically protected within one year?				
§192.455(b)	For pipelines installed without cathodic protection: <u>Are there any pipelines without cathodic protection?</u>				
	(1) Has the operator proved that a corrosive environment does not exist?				
	(2) Conducted tests within 6-months to confirm (#1) above?				
§192.455	**Pipeline Material Types:** What kinds of pipeline materials are used? Steel, Copper, Plastic, Ductile Iron				
§192.455(c)(1)	**For bare copper pipeline:** Is the pipeline cathodically protected if a corrosive environment exists?				
§192.455(c)(2)	**For bare temporary (less than 5 year period of service) pipelines**: For unprotected pipelines, has it been demonstrated that corrosion during the 5-year period will not be detrimental to public safety?				
§192.455(e)	**For aluminum pipeline:** Is the natural pH of the environment <8.0? If not, has operater conducted tests or have experience to indicate the aluminum pipeline suitability with its environment? **SD does not have any aluminum pipe.**				x
§192.455(f)	**Metal alloy fittings on plastic pipelines:**				
	(1) Has operator shown by test, investigation, or experience that adequate corrosion control is provided by the alloy composition?				
	(2) Fitting is designed to prevent leakage caused by localized corrosion pitting?				
	(g) Electrically isolated metal alloy fittings installed after January 22, 2019, that do not meet the requirements of paragraph (f) must be cathodically protected, and must be maintained in accordance with the operator's integrity management plan.				
§192.457(a)	**Pipelines installed before August 1, 1971**: Are effectively coated transmission pipelines cathodically protected?				
§192.457(b)	(Except for cast iron or ductile iron) Is cathodic protection provided in areas of active corrosion on:				
	(1) existing bare or ineffectively coated transmission pipelines?				
	(2) existing bare or coated pipes at compressor, regulator, and measuring stations?				
	(3) existing bare or coated distribution lines?				
§192.459	When the operator has knowledge that any pipeline is exposed, is the exposed pipe examined for:				

XII. PART 192 – EXTERNAL CORROSION CONTROL		S	N/I	U	N/A
	(a) Evidence of corrosion?				
	(b) Coating deterioration?				
§192.459	If external corrosion requiring remedial action is found, is the pipeline investigated circumferentially and longitudinally beyond the exposed portion to determine whether additional corrosion requiring remedial action exists?				
§192.459	Does operator have procedures established for examining exposed **cast iron** pipe for evidence of graphitization? **SD no longer has cast iron pipe.**				**x**
	Does operator have procedures established for remedial measures on **cast iron** pipe if graphitization is discovered, AGA GPTC Appendix G-18 (NTSB)? **SD no longer has cast iron pipe.**				**x**
§192.461(a)	Does the coating on steel pipe meet the requirements of this part?				
	(1) Applied on a properly prepared surface?				
	(2) Has sufficient adhesion to resist underfilm migration of moisture?				
	(3) Sufficiently ductile to resist cracking?				
	(4) Has sufficient strength to resist damage due to handling and soil stress?				
	(5) Compatible with supplemental cathodic protection?				
§192.461(b)	If external coating is electrically insulating does it have low moisture absorption and high electrical resistance?				
§192.461(c)	Is the external coating inspected prior to lowering the pipe into the ditch and is any damage repaired?				
§192.461(d)	Is external protective coating protected from damage resulting from adverse ditch conditions or damage from supporting blocks?				
§192.461(e)	If coated pipe is installed by boring, driving, or similar method, are precautions taken to minimize damage to the coating?				
§192.461 (f) –(i)	Steel Transmission: After back fill a coating survey must be conducted and any damage classified as severe must be repaired. The coating survey must be documented and kept for the life of the system. (Does not apply to Type B gathering)				
§192.463 (a)	Does the level of cathodic protection meet the requirements of Appendix D criteria?				
Appendix D,Part I	(1) a negative (cathodic) voltage of at least 0.85 volt ($Cu\text{-}CuSO_4$ ½ cell) also need to consider IR drop				
	(2) a negative voltage shift of at least 300 millivolts (applies to structure not in contact with metals of different anodic potentials) also need to consider IR drop				
	(3) a minimum negative polarization voltage shift of 100 millivolts (interrupting the protective current and measuring the polarization decay)				
	(4) voltage at least as negative as that originally established at beginning of Tafel segment of E-log-I curve				
	(5) net protective current				
	Refer to Appendix D if aluminum, copper, or other metals are within the system also note that other reference cells besides Cu-CuSO4 half-cells can be used if they meet criteria in Section IV of Appendix D				

XII. PART 192 – EXTERNAL CORROSION CONTROL		S	N/I	U	N/A
§192 Appendix D. Part II	Does the operator criteria consider **IR** drop?				
§192.463 (b)	If amphoteric metals are included in a buried or submerged pipeline containing a metal or different anodic potential are they: **No known amphoteric metals are used in SD.**				
	(1) electrically isolated from the remainder of the pipeline and cathodically protected?; OR				**x**
	(2) cathodically protected at a level that meets the requirements of Appendix D for amphoteric metals?				**x**
§192.463 (c)	Is the amount of cathodic protection controlled to prevent damage to the protective coating or the pipe?				
§192.465(a)	Has each pipeline that is cathodically protected been tested at least once each calendar year not to exceed **15** months?				
§192.465(a)	Are 10 percent of short sections of mains or transmission lines and separately protected service lines distributed over the entire system tested each year on a sampling basis, with a different 10 percent checked each year, so that the entire system is checked in each 10 year period?				
§192.465(b)	Has each cathodic protection rectifier been inspected at least **six** times each year not to exceed **2-1/2** months?				
§192.465(c)	Does the operator check for proper performance of each reverse current switch, diode, and interference bond whose failure would jeopardize structure protection at least **six** times each calendar year, but with intervals not exceeding **2-1/2** months?				
§192.465(c)	Does the operator check for proper performance of other interference bonds at least once each calendar year, at intervals not exceeding **15** months?				
§192.465(d)	Is prompt remedial action taken to correct any deficiencies indicated by the monitoring? (Does not apply to Type B gathering)				
	(a) Shorted Casings (**6** months)				
	(b) Rectifier (**2-1/2** months)				
	(c) Low p/s readings - case by case, depends on cause				
§192.465(e)	Does the operator have bare pipelines?				
	(a) Are they cathodically protected?				
	(b) Are they reevaluated at **3** year intervals not exceeding **39** months?				
	(c) Are remedial measures taken where necessary?				
192.465 (f)	(Does not apply to Type B gathering)				
§192.467	Are buried pipelines electrically isolated from other underground structures?				
	(a) Are casing potentials monitored to detect the presence of shorts once each calendar year, not to exceed 15 months?				
	(b) Does the operator investigate & take appropriate action when indications of casing shorts are found?				
	(c) Does the shorted casing procedure require or has the operator made): (**Enforcement Policy**)				
	(1) Determination of a course of action to correct or negate the effects of the shorts within **6** months of discovery.				

XII. PART 192 – EXTERNAL CORROSION CONTROL		S	N/I	U	N/A
	(2) Verification that a short exists				
	(3) Clearing of the short, if practicable. (This must be considered before alternative measures may be used.)				
	(4) Filling the casing/pipe interstice with high-dielectric casing filler or other material which provides a corrosion inhibiting environment, if it is impractical to clear the short.				
	(5) If (# **3**) & (# **4**) are determined to be impractical, monitor the casing with leak detection equipment for leakage at intervals not exceeding **7-1/2** months, but at least **twice** each calendar year.				
	(6) If a leak is found by monitoring casings with leak detection equipment, immediate corrective action to eliminate the leak & further corrosion.				
	(7) In lieu of other corrective actions, monitoring the condition of the carrier pipe using an internal inspection device at specified intervals.				
§192.467(d)	Inspection and electrical tests must be made to assure that electrical isolation is adequate.				
§192.467(e)	Are insulating devices prohibited in areas where a combustible atmosphere is anticipated unless precautions are made to prevent arcing?				
§192.467(f)	Where pipelines are located in close proximity to electrical transmission tower footings, ground cables or counterpoise, is protection provided to the pipelines against damage due to fault currents or lightning?				
§192.469	Are there sufficient test stations or test points?				
§192.471	(a) Are test leads mechanically secure to pipe and electrically conductive?				
	(b) Are test leads attached to minimize stress concentration on the pipe?				
	(c) Are each bared test lead wire and bared metallic area (at point of connection) coated with an electrical insulating material compatible with the pipe coating and insulation on the wire?				
§192.473 (a)	Does the operator monitor their system for stray currents and take appropriate steps to minimize detrimental effects?				
§192.473 (b)	Does operator design and install each impressed current and/or galvanic anode cathodic protection system to minimize adverse effects on existing adjacent underground metallic structures?				
§192.473 (c)	For transmission: Interference surveys must be used to detect stray current whenever monitoring indicates a significant increase in stray current or when new potential stray current sources are introduced. Analysis, remedial action plan and remedial action must be completed. (Does not apply to Type B gathering)				

XIII. PART 192 – INTERNAL CORROSION CONTROL		S	N/I	U	N/A
§192.475(a)	Is gas tested to determine corrosive properties?				
	What is done to monitor gas that may cause internal corrosion? (Are filters, strainers, separators and drips checked for liquid? Is it documented?)				

XIII. PART 192 – INTERNAL CORROSION CONTROL		S	N/I	U	N/A
	If liquids are found are they required to be analyzed for corrosive properties?				
§192.475(b)	Whenever a pipe segment is removed from a pipeline, is it examined for evidence of internal corrosion?				
	If internal corrosion is found -				
§192.475(b)	(1) Is the adjacent pipe must be investigated to determine the extent of internal corrosion?				
	(2) Is replacement made to the extent required by §§192.485, 192.487, or 192.489?				
	(3) Is remedial action taken (**if required**) to minimize internal corrosion?				
§192.475(c)	Gas containing >0.25 grain of hydrogen sulfide per 100 ft3 (at standard conditions) may not be stored in pipe-type or bottle-type holders.				
§192.476(a)	Design and construction of **transmission line installed after May 23, 2007:**				
	Has transmission line or replacement of line pipe, valve, fitting, or other line component in a transmission line met the following requirements (unless operator proves impracticable or unnecessary):				
	(1) configured to reduce risk liquid collection in line				
	(2) has effective liquid removal features if configuration would allow liquid collection				
	(3) allow for use of devices for monitoring internal corrosion at locations with significant potential for internal corrosion				
§192.476(c)	If operator changes configuration of transmission line, did they evaluate the impact of the change on internal corrosion risk to downstream portion of line and provide for removal of liquids and monitoring of internal corrosion?				
§192.476(d)	Does operator maintain records that demonstrate compliance with this section? Does operator maintain as-built drawings or other construction records if found impracticable or unnecessary to follow (a)(1,2.3)				
§192.477	Are there requirements to incorporate coupons and require coupons **(for corrosive gas only)** to be checked at least **twice** annually not to exceed **7-1/2** months?				
§192.478	Transmission: Additional gas monitoring required when transporting gas with a corrosive constituent. Gas transported in SD is not considered corrosive. (Does not apply to Type B gathering)				x

XIV. PART 192 – ATMOSPHERIC CORROSION CONTROL		S	N/I	U	N/A
§192.479(a)	Have above ground facilities been cleaned and coated?				
§192.479(b)	Is the coating material suitable for the prevention of atmospheric corrosion?				

XIV. PART 192 – ATMOSPHERIC CORROSION CONTROL		S	N/I	U	N/A
§192.481(a)	**Other than a service line:** Does the operator inspect piping exposed to the atmosphere at least once every 3 calendar years, at intervals not to exceed 39 months for onshore piping? **Service Lines:** Does the operator inspect piping exposed to the atmosphere at least once every 5 calendar years, at intervals not to exceed 63 months for onshore piping? If atmospheric corrosion is found on a service line during the most recent inspection, then the next inspection of that pipeline or portion of pipeline must be within 3 calendar years, but with intervals not exceeding 39 months.				
§192.481(b)	During inspection does the operator give particular attention to pipe at soil-to-air interfaces, under thermal insulation, under disbanded coating, at pipe supports, at deck penetrations, and in spans over water?				
§192.481(c)	If atmospheric corrosion is found, does the operator provide protection against the corrosion as required by §192.479?				

XV. PART 192 – REMEDIAL MEASURES: CORROSION		S	N/I	U	N/A
§192.483	Is replacement steel pipe coated and cathodically protected?				
§192.485(a)	For each segment of transmission line with general corrosion and with a remaining wall thickness less than that required for the MAOP of the pipeline, is the section of pipeline replaced, repaired, or has the operating pressure reduced?				
§192.485(b)	For each segment of transmission line with localized pitting to a degree where leakage might result, is the section of pipeline replaced, repaired, or has the operating pressure reduced?				
§192.485(c)	Strength of pipe based on actual remaining wall thickness may be determined by 192.712 (Does not apply to Type B gathering)				
§192.487(a)	General Corrosion -For distribution lines with a remaining wall thickness less than that required for the MAOP of the pipeline or a remaining wall thickness less than 30 percent of the nominal wall thickness, does the operator replace or repair the pipe?				
§192.487(b)	Localized Corrosion -For distribution lines, does the operator replace or repair pipe with localized corrosion pitting?				
§192.489(a)	Is each segment of cast iron or ductile iron pipe on which **general** graphitization is found to a degree where a fracture or any leakage might result, replaced? No cast or ductile iron in South Dakota				**x**
§192.489(b)	Is each segment of cast iron or ductile iron pipe on which **localized** graphitization is found to a degree where any leakage might result, replaced or repaired, or sealed by internal sealing methods? No cast or ductile iron in South Dakota				**x**

XVI. PART 192 – CORROSION CONTROL RECORDS		S	N/I	U	N/A
§192.491(a)	Does the operator maintain records or maps showing the location of cathodically protected pipe and facilities?				
§192.491(b)	Does the operator retain records showing the location of cathodically protected pipe and facilities for the life of the system?				

XVI. PART 192 – CORROSION CONTROL RECORDS		S	N/I	U	N/A
§192.491(c)	Does the operator maintain a record of each test, survey, or inspection required by this subpart in sufficient detail to demonstrate adequacy of corrosion control measures or that a corrosive condition does not exist for at least 5 years?				
§192.491(c)	Does the operator retain records related to §§192.465(a) and (e) and 192.475(b) retained for as long as the pipeline remains in service? External corrosion monitoring and internal corrosion monitoring records must be retained for the life of the system. Atmospheric corrosion monitoring only needs to be kept for the last two inspections.				
§192.493	Transmission Only - Do in-line inspections comply with API STD 1163 and NACE SP0102? revised with Mega Rule implementation 7/1/2020 (Or in TIMP Plan) (Does not apply to Type B gathering)				

XVII. PART 192 – TEST REQUIREMENTS FOR PIPELINES		S	N/I	U	N/A
§192.503(a)	Is each segment of pipe pressure tested to substantiate the MAOP prior to putting it into service or returning it to service?				
	Are gauges used for testing checked to ensure they are accurate?				
§192.503(b)	The test medium (liquid, air, natural gas, or inert gas) is: (1) Compatible with the material of which the pipeline is constructed; (2) Relatively free of sedimentary materials; and, (3) Except for natural gas, nonflammable.				
§192.503(c)	Except as provided in §192.505(a), if air, natural gas, or inert gas is used as the test medium, the appropriate maximum hoop stress limitations apply.				
§192.503(d)	Is each non-welded joint used to tie in a test segment leak tested at not less than its operating pressure? (yes or no)				
§192.503(e)	If a component other than pipe is being replaced or added, a strength test is not required if the manufacturer certifies that: 1) component was tested to a least the pressure required for the pipeline to which it is being added. 2) component was manufactured under quality control system that ensures the component is at least equal in strength to a prototype that was tested. 3) component carries a pressure rating established though applicable ASME/ANSI.				
192.505(a)	**Steel Pipelines Operating at greater than or equal to 30% SMYS** *Note: in class 1 or 2 locations if there is a building intended for human occupancy within 300 ft, a hydrostatic test must be conducted to a test pressure of at least 125% of MOP. If the buildings are evacuated while hoop stress exceeds 50% of SMYS then air or gas may be used as a test medium.*				
§192.505(b)	Compressor stations, regulator station and measuring station must be tested to at least Class 3 location test requirements.				
§192.505(c)	Is the pressure at or above test pressure for at least eight hours? (yes or no)				
§192.505(d)	Does the procedure for short sections of pipe require a pressure tested for at least four hours before they are installed, if it is impractical to pressure test after installation?				

XVII. PART 192 – TEST REQUIREMENTS FOR PIPELINES		S	N/I	U	N/A
§192.506	Transmission Lines: Are there requirements for spike hydrostatic testing? revised with Mega Rule implementation 7/1/2020 (Or in TIMP Plan) (Does not apply to Type B gathering)				
§192.507(a)	**Pipelines Operating at less than 30 percent of SMYS and at or above 100 psig.**				
	Does the operator use a test procedure that will ensure discovery of all potentially hazardous leaks in the segment being tested?				
§192.507(b)	If the segment is stressed to 20 percent or more of SMYS and is using natural gas, inert gas, or air is one of the following used: - A leak test at a pressure between 100 psig and the pressure required to produce a hoop stress of 20 percent of SMYS; or - The line is walked to check for leaks while the hoop stress is held at approximately 20 percent of SMYS List or highlight the one used.				
§192.507(c)	Is the pressure maintained at or above the test pressure for at least one hour? (yes or no)				
§192.507(d)	For fabricated units and short sections of pipe, for which a post installation test is impractical, a preinstallation pressure test must be conducted in accordance with the requirements of this section.				
§192.517	Pressure test records must be kept for the life of the system when tested to 192.507 (above).				
§192.517	All transmission pressure test records (Records for 192.505, 192.506 & 192.507) must be kept for the life of the system and include the following: Operators name and name of employee responsible Test medium used Test pressure Test duration Pressure recording charts or other records for recording readings Elevation variations, whenever significant for the particular test Leaks and failures noted and their disposition revised with Mega Rule implementation 7/1/2020				
§192.509, §192.511, §192.513 and §192.517	**For distribution mains and services**				
	Are pressure test records maintained that contain the following information (these records must be maintained for at least 5 years):				
	- Date				
	-Operator name & name of operator employee responsible for making the test.				
	- Location of test				
	- Test pressure applied				
	- Test medium used.				
	- Test duration				
§192.509(b)	**Test Requirements for (steel) pipelines to operate below 100 psig** Are steel main that are to be operated at less than 1 psig required to be tested to at least 10 psig?				
§192.509(b)	Are each steel mains that are to be operated at or above 1 psig required to be tested to at least 90 psig?				

XVII. PART 192 – TEST REQUIREMENTS FOR PIPELINES		S	N/I	U	N/A
§192.511(a)	**Service Lines** If feasible, is the connection to the main required to be included in the test? (yes or no)				
§192.511(b)	Are service lines expected to operate at a pressure of at least 1 psig but not more than 40 psig required to be tested at a pressure of not less than 50 psig?				
§192.511(c)	Are service lines expected to operate at a pressure of more than 40 psig required to be tested at a pressure of not less than 90 psig?				
§192.511(c)	Are steel service lines stressed to 20% or more of SMYS tested in accordance with §192.507?				
§192.513	**Test Requirements for plastic pipelines.** (a) Is each segment of a plastic pipeline tested in accordance with this section? (yes or no) (b) The test pressure must insure discovery of all potentially hazardous leaks in the segment being tested.				
§192.513(c)	(c) The test *pressure* must be at least 150% of the maximum operating pressure or 50 psi (345 kPa) gauge, whichever is greater. However, the maximum test pressure may not be more than 2.5 times the pressure determined under § 192.121 at a *temperature* not less than the pipe temperature during the test.				
§192.513(d)	During the test, is the temperature of the pipe not more than 100ºF, or the temperature at which the long term hydrostatic strength has been determined, whichever is greater? (yes or no and list out which one is greater for each operator)				
§192.515	**Environmental protection and safety requirements** Whenever the hoop stress of the segment will be tested in excess of 50% SMYS the operator must take safety precautions to protect people and the test medium must be disposed of in an appropriate manner.				

XVIII. PART 192 – UPRATING		S	N/I	U	N/A
§192.553	Does the operator have a procedure for uprating? Does it include the following:				
§192.553(a)	(a) Pressure increases. Is the increase in operating pressure made in increments? Is the pressure increased gradually, at a rate that can be controlled?				
§192.553(a)(1)	At the end of each incremental increase, is the pressure held constant while the entire segment of the pipeline is checked for leaks?				
§192.553(a)(2)	Is each leak detected repaired before a further pressure increase is made? (except that a leak determined not to be potentially hazardous need not be repaired, if it is monitored during the pressure increase and it does not become potentially hazardous)				
§192.553(b)	Do uprate records identify work performed and each pressure test conducted?				
	Are these records retained for the life of the segment?				
§192.553(c)	Is a written procedure established that will ensure that each part of the uprating meets requirements?				

XVIII. PART 192 – UPRATING		S	N/I	U	N/A
§192.553(d)	Are limitations on increases in MAOP followed? (Except as provided in §192.555 (c), a new maximum allowable operating pressure established under this subpart may not exceed the maximum that would be allowed under §§ 192.619 and 192.621 for a new segment of pipeline constructed of the same materials in the same location. However, when uprating a steel pipeline, if any variable necessary to determine the design pressure under the design formula (§192.105) is unknown, the MAOP may be increased as provided in §192.619(a)(1).)				
§192.555	**Uprating to a pressure that will produce a hoop stress of 30 percent or more of SMYS in steel pipelines.** (a) Unless the requirements of this section have been met, no *person* may subject any segment of a *steel pipeline* to an operating *pressure* that will produce a *hoop stress* of 30 percent or more of *SMYS* and that is above the established *maximum allowable operating pressure*. (b) Before increasing operating pressure above the previously established maximum allowable operating pressure the *operator* shall: (1) Review the design, operating, and maintenance history and previous testing of the segment of pipeline and determine whether the proposed increase is safe and consistent with the requirements of this part; and (2) Make any repairs, replacements, or alterations in the segment of pipeline that are necessary for safe operation at the increased pressure.				
	(c) After complying with paragraph (b) of this section, an operator may increase the maximum allowable operating pressure of a segment of pipeline constructed before September 12, 1970, to the highest pressure that is permitted under §192.619, using as test pressure the highest pressure to which the segment of pipeline was previously subjected (either in a strength test or in actual operation).				

XVIII. PART 192 – UPRATING		S	N/I	U	N/A
	(d) After complying with paragraph (b) of this section, an operator that does not qualify under paragraph (c) of this section may increase the previously established maximum allowable operating pressure if at least one of the following requirements is met: (1) The segment of pipeline is successfully tested in accordance with the requirements of this part for a new line of the same material in the same location. (2) An increased maximum allowable operating pressure may be established for a segment of pipeline in a Class 1 location if the line has not previously been tested, and if: (i) It is impractical to test it in accordance with the requirements of this part; (ii) The new maximum operating pressure does not exceed 80 percent of that allowed for a new line of the same design in the same location; and, (iii) The operator determines that the new maximum allowable operating pressure is consistent with the condition of the segment of pipeline and the design requirements of this part.				
	(e) Where a segment of pipeline is uprated in accordance with paragraph (c) or (d)(2) of this section, the increase in pressure must be made in increments that are equal to: (1) 10 percent of the pressure before the uprating; or (2) 25 percent of the total pressure increase, whichever produces the fewer number of increments.				
§192.557(a)	**Uprating to a pressure that will produce a hoop stress less than 30% of SMYS: plastic, cast iron and ductile iron pipelines.** Unless the requirements of this section have been met, no person may subject:				
	(1) A segment of steel pipeline to an operating pressure that will produce a hoop stress less than 30 percent of SMYS and that is above the previously established maximum allowable operating pressure; or				
	(2) A plastic, cast iron, or ductile iron pipeline segment to an operating pressure that is above the previously established maximum allowable operating pressure.				
§192.557(b)	Before increasing operating pressure above the previously established maximum allowable operating pressure, the operator shall:				
	(1) Review the design, operating, and maintenance history of the segment of pipeline;				
	(2) Make a leakage survey (if it has been more than 1 year since the last survey) and repair any leaks that are found, except that a leak determined not to be potentially hazardous need not be repaired, if it is monitored during the pressure increase and it does not become potentially hazardous;				
	(3) Make any repairs, replacements, or alterations in the segment of pipeline that are necessary for safe operation at the increased pressure;				
	(4) Reinforce or anchor offsets, bends and dead ends in pipe joined by compression couplings or bell spigot joints to prevent failure of the pipe joint, if the offset, bend, or dead end is exposed in an excavation;				
	(5) Isolate the segment of pipeline in which the pressure is to be increased from any adjacent segment that will continue to be operated at a lower pressure; and,				

XVIII. PART 192 – UPRATING		S	N/I	U	N/A
	(6) If the pressure in main or service lines, or both, is to be higher than the pressure delivered to the customer, install a service regulator on each service line and test each regulator to determine that it is functioning. Pressure may be increased as necessary to test each regulator, after a regulator has been installed on each pipeline subject to the increased pressure.				
§192.557(c)	After complying with paragraph (b) of this section, the increase in maximum allowable operating pressure must be made in increments that are equal to 10 p.s.i. (69 kPa) gage or 25 percent of the total pressure increase, whichever produces the fewer number of increments. Whenever the requirements of paragraph (b)(6) of this section apply, there must be at least two approximately equal incremental increases.				
§192.557(d)	If records for cast iron or ductile iron pipeline facilities see §192.557(d).				

XIX. PART 192 – START UP & SHUT DOWN PROCEDURES		S	N/I	U	N/A
§192.605(b)(5)	Do the operator's procedures include starting up and shutting down any part of the pipeline in a manner designed to assure operation within the MAOP limits prescribed by this part, plus the build-up allowed for operation of pressure-limiting and control devices?				

XX. PART 192 – ABNORMAL OPERATIONS: TRANSMISSION LINES		S	N/I	U	N/A
	Does the Operator have a procedure for abnormal operations?				
§192.605(c)(4)	Does a procedure require that if an abnormal operation occurs, that the operator review personnel response considering the actions taken, whether procedures were followed, and whether procedures were adequate or should be revised? Is the review documented?				
§192.607	Are MAOP records traceable, verifiable, and complete? If they are not TVC is there a procedure for collecting this information? (See code for requirements.) (Transmission in an HCA, Class 3, or Class 4 and >=30% SMYS: If not TVC, an MAOP reconfirmation is required see 192.624.) revised with Mega Rule implementation 7/1/2020				

XXI. PART 192 – CHANGE IN CLASS LOCATION		S	N/I	U	N/A
§192.609	(Transmission >40% SMYS) Does the operator have a process for doing a class location study?				
§192.610	If there is a class location change and pipe is replaced, then a review of the valve spacing and rupture mitigation valves much be completed. (see code)				
§192.611	Is there a procedure for the MAOP to be confirmed or revised when a change in class location occurs? Are there procedures to: (a) Test the pipe to qualify the new MAOP.				
	(b) Reduce MAOP to meet the class location.				
	(d) Confirmation or revision of the maximum allowable operating pressure that is required as a result of a study under §192.609 (must be completed within 24 months of the change in class location).				

XXI. PART 192 – CHANGE IN CLASS LOCATION		S	N/I	U	N/A
	Refer to 192.611 if MAOP is confirmed or revised (also see Subpart K if applicable)				

XXII. PART 192 – SURVEILLANCE		S	N/I	U	N/A
§192.613(a)	Has the operator conducted continuing surveillance to determine if the following issues need to be addressed: - Change in class location - Failures - Leakage history - Corrosion - Cathodic protection - Other unusual conditions If yes, provide explanation of issues operator feels need to be addressed.				
§192.613(b)	Has the operator documented and initiated a program to correct problems discovered?				
§192.613(c)	Is there a procedure for inspecting transmission facilities after an extreme weather event or natural disaster? Is the inspection required to begin within 72 hours? Is there a requirement to take prompt remedial action?				

XXIII. PART 192 – DAMAGE PREVENTION		S	N/I	U	N/A
§192.614	Does the operator have a damage prevention program? (Required for Type B Gathering)				
	Do the operator's and operator's contractors drilling/boring procedures include actions to protect their facilities from the dangers posed by drilling and other trenchless technologies?				
	Does the operator have a procedure for marking facilities?				
	Does the operator have company personnel on site during excavations?				
	What actions are taken when damage prevention procedures are not followed?				

XXIV. PART 192 – FAILURE INVESTIGATION		S	N/I	U	N/A
§192.617	a) Does the operator have a procedure for failure investigations? Does it include sending failure to lab for analysis if appropriate?				
	b) Does the operator develop, implement and incorporate lessons learned from the failure or incident review into its procedures? Does it include personnel training, qualification programs, design, construction, testing, maintenance, operations and emergency procedures?				
	c) (Transmission) Does the operator have a procedure that if an incident involves closure of a rupture mitigation valve (RMV) or alternative equipment that there is post incident analysis of all the factors that may have been impacted. (see code for more information) Rupture rule				

	d) (Transmission) Rupture post-failure and incident summary must be completed within 90 days. (see code for more information) Rupture rule				

XXV. PART 192 – MAXIMUM ALLOWABLE OPERATING PRESSURE		S	N/I	U	N/A
	Does the operator determine MAOP correctly? (Required for Type B Gathering)				
§192.619/ §192.621/ §192.623	Is the MAOP commensurate with the class location? revised with Mega Rule implementation 7/1/2020				
	(a) How is the MAOP determined? (1) By design pressure of weakest element? (See Subparts C & D)				
	(2) By test pressure				
	(3) By highest operating pressure to which the segment of line was subjected during the preceding 5 years.				
	(4) Pressure determined by operator to be maximum safe pressure.				
§192.619	(a)(1) Is there a procedure for determining MAOP for pipelines being converted under 192.14?				
	(e) Transmission operators that meet the criteria of 192.624 must establish and document the MAOP of each pipeline segment in accordance with 192.624. (Transmission in an HCA, Class 3, or Class 4 and >=30% SMYS: If not TVC, an MAOP reconfirmation is required see 192.624.)				
	(f) Transmission operators must make and retain records necessary to establish and document the MAOP				
§192.624	Transmission Only: Is there a procedure for reconfirmation of the pipeline's MAOP? revised with Mega Rule implementation 7/1/2020				
§192.632	Transmission Only: Is there a procedure for an Engineering Critical Assessment for MAOP as necessary? revised with Mega Rule implementation 7/1/2020 (Or in TIMP Plan)				

XXVI. PART 192 – ODORIZATION OF GAS		S	N/I	U	N/A
§192.625(a)	Distribution – Is the gas required to be odorized to a level that gas is detectable at one-fifth of the lower explosive limit.				
	Odorization Method –				
§192.625(b)	Transmission Lines in Class 3 or 4 locations must comply with 192.625(a) if 50% or less of the length of the line downstream is in a Class 1 or 2 location. There are also other exceptions found within this section				
§192.625(e)	Does the equipment introduce the odorant without wide variations in the level of odorant?				
§192.625(f)	Does the operator conduct periodic sampling of combustible gases using an instrument capable of determining the percentage of gas in air at which the odor becomes readily detectable?				

XXVI. PART 192 – ODORIZATION OF GAS		S	N/I	U	N/A
	Are the instruments required to be calibrated per the manufacturer's instructions?				

XXVII. PART 192 – HOT TAPPING		S	N/I	U	N/A
§192.151	Is there a procedure for tapping pipelines under pressure?				
§192.627	Are hot taps made by qualified personnel?				

XXVIII. PART 192 – PIPELINE PURGING		S	N/I	U	N/A
§192.629	Purging of pipelines must be done to prevent entrapment of an explosive mixture in the line.				
§192.629(a)	Are the lines which contain air properly purged with gas?				
§192.629(b)	Are lines containing gas properly purged with air (or inert gas)?				

XXIX. PART 192 – MAINTENANCE		S	N/I	U	N/A
§192.703(b)	Is each segment of a pipeline that becomes unsafe, replaced, repaired or removed from service? (Required for Type B Gathering)				
§192.703(c)	Are hazardous leaks repaired promptly? (Required for Type B Gathering)				
	How are non-hazardous leaks handled?				
	If monitoring is done, how is monitoring defined?				
Adv. Bulletin 6/10/2021	How is eliminating hazardous leaks addressed?				
Adv. Bulletin 6/10/2021	What steps have been taken to minimize release of natural gas from pipelines?				

XXX. PART 192 – PATROLLING TRANSMISSION			S	N/I	U	N/A
§192.705(a)	Does the operator patrol surface conditions for indications of leaks, construction activity, or other factors on and adjacent to line ROW?					
	(a) Does the operator follow up on problems noted?					
§192.705(b)	Is the maximum interval between patrols in accordance with the following: **(Maximum interval between patrols of lines)**					
Class location	At Highway and Railroad Crossings	At all Other Places				
1 and 2	**2/yr (7-1/2 months)**	**1/Year (15 months)**				
3	**4/yr (4-1/2 months)**	**2/yr (7-1/2 months)**				
4	**4/yr (4-1/2 months)**	**4/yr (4-1/2 months)**				

XXXI. PART 192 – LEAK SURVEYS: TRANSMISSION		S	N/I	U	N/A
§192.706	(a) Are leakage surveys of transmission lines conducted at intervals not exceeding 15 months but at least once each calendar year? (Required for Type B Gathering)				
	(b) Are lines transporting unodorized gas surveyed using leak detector equipment at intervals not exceeding 7-1/2 months but at least twice each calendar year for Class 3 locations and at intervals not exceeding 4-1/2 months but at least 4 times each calendar year for Class 4 locations?				

XXXII. PART 192 – LINE MARKERS		S	N/I	U	N/A
§192.707(a)	Are buried mains and transmission lines marked as required in the following areas: (Required for Type B Gathering)				
	(1) at each crossing of a public road and railroad				
	(2) wherever necessary to identify the location of the line to reduce possibility of damage or interference				
§192.707(c)	Are line markers installed on aboveground areas accessible to the public?				
§192.707(d)	Do the line markers have the latest characteristics?				
	(1) "Warning", "Caution", "Danger" followed by "Gas Pipeline" (1" high with ¼" stroke except in heavily developed areas)				
	(2) name and telephone number of operator (24 hr access)				

XXXIII. PART 192 – FIELD REPAIRS: TRANSMISSION LINES		S	N/I	U	N/A
192.709(a)	Are field repair records (for the pipe) maintained that contain the following information (these records must be maintained for the life of the pipeline):				
	- Date				
	- Location of repair				
	- Description of each repair made (including pipe-to-pipe connections)				
192.709(b)	Are field repair records (for parts of the system other than the pipe) maintained that contain the following information (these records must be maintained for at least 5 years):				
	- Date				
	- Location of repair				
	- Description of each repair made				
192.709(c)	*Note: Repairs generated by patrols, surveys, inspections, or tests required by subparts L and M of this part must be retained for at least 5 years or until the next patrol, survey, inspection, or test is completed (whichever is longer).*				
§192.710	Transmission lines that operate at greater than 30% SMYS: Is there a procedure for determining areas located in Class 3 or Class 4 locations or moderate consequence areas. revised with Mega Rule implementation 7/1/2020 (Or in TIMP Plan)				
§192.711(a)	Temporary repairs. Each operator must take immediate temporary measures to protect the public whenever: (1) A leak, imperfection, or damage that impairs its serviceability is found in a segment of steel transmission line operating at or above 40 percent of the SMYS; and (2) It is not feasible to make a permanent repair at the time of discovery.				

XXXIII. PART 192 – FIELD REPAIRS: TRANSMISSION LINES		S	N/I	U	N/A
§192.711(b)	Permanent repairs. An operator must make permanent repairs on its pipeline system according to the following: (1) Non integrity management repairs: The operator must make permanent repairs as soon as feasible. (2) Integrity management repairs: When an operator discovers a condition on a pipeline covered under Subpart O-Gas Transmission Pipeline Integrity Management, the operator must remediate the condition as prescribed by § 192.933(d).				
§192.711(c)	No welded patches may be used.				
§192.712	Is there a procedure for doing an analysis of predicted failure pressure if required (by 192.485 and/or 192.714)? revised with Mega Rule implementation 7/1/2020 (Or in TIMP Plan)				
§192.713(a)	(a) Each imperfection or damage that impairs the serviceability of pipe in a steel transmission line operating at or above 40 percent of SMYS must be- (1) Removed by cutting out and replacing a cylindrical piece of pipe; or (2) Repaired by a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe.				
§192.713(b)	Operating pressure must be at a safe level during repair operations.				
§192.714	**Repair Criteria** Transmission – not located in an HCA: Repair Criteria Are there procedures for repairs not located in HCAs? (See code for all details.) (a) Operating pressure must be less than predicted failure per 192.712 during repair and materials must be TVC (b) Conditions must be remediated according to a schedule that prioritizes the conditions (c) Remediation must occur immediately on the following: a. Metal loss where predicted failure is less than or equal to 1.1 x MAOP b. A dent located between 8 o'clock and 4 o'clock c. Metal loss greater than 80% d. Metal loss affects the longitudinal seam and predicted failure is less than 1.25 x MAOP e. A crack or crack-like anomaly meeting the criteria (see code) f. Any anomaly that is judged to need immediate action (d) Remediation must occur within 2 year of discovery if: a. A smooth dent between 8 o'clock and 4 o'clock with a depth greater than 6% (unless analysis by 192.712 (c) shows critical strain levels are not exceeded.) b. A dent with depth greater than 2% that affects curvature at the girth weld or longitudinal or helical seam weld, (unless analysis by 192.712(c) shows critical strain levels are not exceeded.) c. Metal loss anomalies – calculation of the remaining strength per 192.712(b) is: less than 1.39 x MAOP for Class 2, or less than 1.5 x MAOP for Class 3 or 4. Class 1 locations with predicted failure pressure greater than 11 x MAOP must follow remediation schedule in ASME/ANSI B31.8S. d. Metal loss at crossing of another pipeline, is in an area with widespread circumferential corrosion or could				

XXXIII. PART 192 – FIELD REPAIRS: TRANSMISSION LINES		S	N/I	U	N/A
	affect a girth weld and that has a predicted failure pressure (192.712(b)) less than 1.39 x MAOP for Class 1 or 1.5 x MAOP for Class 2, 3 or 4. e. Metal loss preferentially affecting a longitudinal seam and predicted failure pressure (192.712(d)) is less than 1.39 x MAOP for Class 1 or less than 1.5 x MAOP for Class 2, 3, and 4. f. A crack or crack-like anomaly that has a predicted failure pressure (192.712(d)) that is less than 1.39 x MAOP for Class 1 or less than 1.5 x MAOP for Class 2, 3, and 4. (e) An operator must record and monitor during subsequent risk assessments the following: a. A dent between 4 o'clock and 8 o'clock with a depth greater than 6% b. A dent between 8 o'clock and 4 o'clock with a depth greater than 6% and where engineering analysis determines critical strain levels are not exceeded. (192.712(c)) c. A dent with depth greater than 2% that affects curvature at the girth weld or longitudinal or helical seam weld, (unless analysis by 192.712(c) shows critical strain levels are not exceeded.) d. A dent that has metal loss, cracking or a stress riser and where an engineering analysis demonstrates critical strain levels are not exceeded. (192.712(c)) e. Metal loss preferential affecting a longitudinal seam where predicted failure pressure (192.712(d) is greater than or equal to 1.39 x MAOP for Class 1 or greater than or equal to 1.5 x MAOP for Class 2, 3 or 4 f. A crack or crack-like anomaly which the predicted failure pressure (192.712(d)) is greater than or equal to 1.39 x MAOP for Class 1 or greater than or equal to 1.5 x MAOP for Class 2, 3 or 4 (f) Temporary pressure reduction must be taken immediately until the operator remediates the conditions above. a. 80% of operating pressure b. Pressure not exceeding the predicted failure pressure x the design factor for the class location. c. Pressure not exceeding the predicted failure pressure divided by 1.1 (g) Must notify PHMSA if can't meet the required schedule. (h) Most notify PHMSA if pressure reduction exceeds 365 days (i) Operator must document and keep records of calculations and decisions made to determine the reduced operating pressure and implementation of the reduced operating pressure for 5 years after repair. (j) In situ direct examination of crack defects – whenever an operator finds conditions that need to be repaired in accordance with this section, an operator must perform a direct examination of known locations of cracks or crack-like defects (see code)				

XXXIII. PART 192 – FIELD REPAIRS: TRANSMISSION LINES		S	N/I	U	N/A
§192.715	**Permanent field repair of welds** Is each weld found not acceptable under 192.241(c) repaired properly? (a) Take segment of line out off service and repair according to 192.245 (b) The line may remain in service if: a. The weld is not leaking b. The pressure is reduced to 20% SMYS c. Grinding can be limited so that at least 1/8 inch of pipe weld remains (c) If repair can't be made with a or b above then a full encirclement welded split sleeve must be used for the repair.				
§192.717	Do weld repairs meet the following? **Permanent field repair of leaks.** Each permanent field repair of a leak on a transmission line must be made by- (a) Removing the leak by cutting out and replacing a cylindrical piece of pipe; or (b) Repairing the leak by one of the following methods: (1) Install a full encirclement welded split sleeve of appropriate design, unless the transmission line is joined by mechanical couplings and operates at less than 40 percent of SMYS. (2) If the leak is due to a corrosion pit, install a properly designed bolt-on-leak clamp. (3) If the leak is due to a corrosion pit and on pipe of not more than 40,000 psi (267 Mpa) SMYS, fillet weld over the pitted area a steel plate patch with rounded corners, of the same or greater thickness than the pipe, and not more than one-half of the diameter of the pipe in size. (4) If the leak is on a submerged offshore pipeline or submerged pipeline in inland navigable waters, mechanically apply a full encirclement split sleeve of appropriate design. (5) Apply a method that reliable engineering tests and analyses show can permanently restore the serviceability of the pipe.				
	Testing of repairs				
§192.719(a)	Is replacement pipe tested to the requirement of a new line installed in the same location and records maintained as required under Subpart J Testing Requirements? *(Note: the pipe may be tested before it is installed)* Is it examined in accordance with 192.241?				
§192.720	**Distribution systems: Leak repair.** Mechanical leak repair clamps installed after January 22, 2019 may not be used as a permanent repair method for plastic pipe.				
§192.750	Is there a procedure for launcher and receiver safety. revised with Mega Rule implementation 7/1/2020				

XXXIV. PART 192 – PATROLLING DISTRIBUTION		S	N/I	U	N/A
§192.721(a)	Frequency of patrolling mains must be determined by the severity of the conditions which could cause failure or leakage (i.e., consider cast iron, weather conditions, known slip areas, etc.)				
§192.721(b)(1)	Does the operator patrol mains in business districts at intervals not exceeding **4-1/2** months, but at least **4** times each calendar year where anticipated physical movement or external loading could cause failure or leakage?				
§192.721(b)(2)	Does the operator patrol mains outside business districts at intervals not exceeding **7-1/2** months, but at least **2** times each calendar year where anticipated physical movement or external loading could cause failure or leakage?				
	How has the operator defined a business district?				

XXXV. PART 192 – LEAKAGE SURVEYS: DISTRIBUTION		S	N/I	U	N/A
§192.605(b)	Procedures for §192.723 – Leak Survey?				
§192.723(b)(1)	Does the operator conduct gas detector surveys in the business district at intervals not exceeding 15 months, but at least once each calendar year?				
§192.723(b)(2)	Does the operator conduct leakage surveys (to include manholes/cracks in pavement/other pertinent locations) of the distribution system outside of the principal business areas at intervals not exceeding 63 months, but at least once every 5 calendar year?				
	For cathodically unprotected distribution lines subject to §192.465(e) on which electrical surveys for corrosion are impractical is a leakage survey conducted at least once every 3 calendar years at intervals not exceeding 39 months?				

XXXVI. PART 192 – TEST REQUIREMENTS FOR REINSTATING SERVICE LINES		S	N/I	U	N/A
§192.725(a)	Does the operator test reinstated service lines in the same manner as new lines and maintain records as required by Subpart J?				
§192.725(b)	Is each service line that is temporarily disconnected tested from the point of disconnection and records maintained as required by Subpart J?				

XXXVII. PART 192 – ABANDONMENT OR DEACTIVATION OF FACILITIES		S	N/I	U	N/A
§192.605(b)	Does the O&M Plan provide for abandonment or deactivation of pipelines?				
§192.727(b)	Is each pipeline that is abandoned in place, disconnected from all sources and supplies of gas, purged of gas, and sealed at both ends?				
§192.727(c)	Is each inactive pipeline (except service lines) that is not being maintained, disconnected from all sources and supplies of gas, purged of gas, and sealed at both ends?				
§192.727(d)(1)(2)(3)	When discontinuing service to a customer, does the operator lock or take other means to prevent a valve from being opened by unauthorized persons, or use other means?				

XXXVIII. PART 192 – PRESSURE LIMITING AND REGULATING STATIONS		S	N/I	U	N/A
§192.181(b)	Each regulator station controlling the flow or pressure of gas in a distribution system must have a 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.				
§192.195	(a) General requirements. Except as provided in §192.197, 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, must have pressure relieving or pressure limiting devices that meet the requirements of §192.199 and §192.201. (b) Additional requirements for distribution systems. 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 must (1) Have 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) Be designed so as to prevent accidental overpressuring.				
§192.739(a)	Does the operator perform and document inspections on pressure limiting relief devices and pressure regulators not to exceed 15 months, but at least annually to determine the following:				
	In good mechanical condition?				
	Adequate from the standpoint of capacity and reliability of operation for the service in which it is employed?				
	Set to control or relieve at the correct pressures consistent with the pressure limits of §192.201(a)? (See exception in §192.739(b))				
	(d) Properly installed and protected from dirt, liquids or other conditions that might prevent proper operation?				
§192.739(b)	Does the operator have any steel pipelines whose MAOP is determined under §192.619(c)? *If yes, the following control or relief pressures apply and inspector should double check operator calculations.* If the MAOP is 60 PSI gage or more, the control or relief pressure limit is as follows:				
	If the MAOP produces a hoopstress of: 1) 72 percent or greater then the pressure limit, is the MAOP plus 4 percent. 2) Unknown as a percentage of SMYS, then the pressure limit is a pressure that will prevent unsafe operation of the pipeline considering its operating and maintenance history and MAOP.				

XXXVIII. PART 192 – PRESSURE LIMITING AND REGULATING STATIONS		S	N/I	U	N/A
§192.743	Does the operator perform and document inspections on relief devices not to exceed 15 months but at least once each calendar year to determine the following?				
	(a) Has sufficient capacity been determined by testing in place or by review and calculations?				
	(b) Are calculations used to determine capacity available?				
	(c) Required that unsatisfactory conditions be corrected in an appropriate time frame?				
§192.740(b)	**Farm Taps:** Each pressure regulating or limiting device, relief device (except rupture discs), automatic shutoff device, and associated equipment must be inspected and tested at least once every 3 calendar years, not exceeding 39 months, to determine that it is:				
	(1) In good mechanical condition;				
	(2) Adequate from the standpoint of capacity and reliability of operation for the service in which it is employed;				
	(3) Set to control or relieve at the correct pressure consistent with the pressure limits of §192.197; and to limit the pressure on the inlet of the service regulator to 60 psi (414 kPa) gauge or less in case the upstream regulator fails to function properly; and				
	(4) Properly installed and protected from dirt, liquids, or other conditions that might prevent proper operation.				
	Are farm taps include in the DIMP program? (Enforcement Discretion, March 2019)				
§192.740(c)	This section does not apply to equipment installed on: 1. A service line that only serves engines that power irrigation pumps; 2. A service line included in a distribution integrity management plan				

XXXIX. PART 192 – TELEMETERING OR RECORDING GAUGES-DISTRIBUTION		S	N/I	U	N/A
§192.741(a)	Does the operator have telemetering or pressure recording gauges to indicate gas pressure in the district that is supplied by more than one district pressure regulating station? (yes or no)				
§192.741(b)	Has the operator determined if telemetering or pressure recording gauges are needed for a distribution system supplied by only one district pressure regulating station? (yes or no) How does the operator decide where telemetering or recording gauges are installed?				
§192.741(c)	Does the operator inspect equipment and take corrective measures when there are indications of abnormally high or low pressure? (yes or no)				
	Are these inspections documented within the operator's records? (yes or no)				

XL. PART 192 – VALVE DESIGN AND MAINTENANCE: TRANSMISSION		S	N/I	U	N/A
	Is there a procedure to determine valves that might be used in an emergency?				
§192.179	(a) Each transmission line, other than offshore segments, must have sectionalizing block valves spaced as follows, unless in a particular case the Administrator finds that alternative spacing would provide an equivalent level of safety: (1) Each point on the pipeline in a Class 4 location must be within 2 1/2 miles (4 kilometers) of a valve. (2) Each point on the pipeline in a Class 3 location must be within 4 miles (6.4 kilometers) of a valve. (3) Each point on the pipeline in a Class 2 location must be within 7 1/2 miles (12 kilometers) of a valve. (4) Each point on the pipeline in a Class 1 location must be within 10 miles (16 kilometers) of a valve.				
	(b) Each sectionalizing block valve on a transmission line, other than offshore segments, must comply with the following: (1) The valve and the operating device to open or close the valve must be readily accessible and protected from tampering and damage. (2) The valve must be supported to prevent settling of the valve or movement of the pipe to which it is attached.				
	(c) Each section of a transmission line, other than offshore segments, between main line valves must have a blowdown valve with enough capacity to allow the transmission line to be blown down as rapidly as practicable. Each blowdown discharge must be 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.				
	(e) & (f) Transmission lines 6” or larger constructed or replaced after 4/10/2023 must have rupture-mitigation valves (RMV) or alternative technology and meet the requirements of 192.634 and 192.636. Rupture rule (Does not apply to Type B gathering)				
§192.634	(Transmission line 6” or larger constructed or replaced after 4/10/2023) maximum spacing between valves. (see code) (Does not apply to Type B gathering)				
§192.636	(Transmission line 6” or larger constructed or replaced after 4/10/2023) Response to rupture; capabilities of rupture-mitigation valves or alternative equipment. (see code) (Does not apply to Type B gathering)				
§192.745(a)	Does the operator check and service each valve which might be required during an emergency at intervals not exceeding 15 months, but at least once each calendar year?				
§192.745(b)	Does the operator take prompt remedial action to correct any valve found inoperable, unless the operator designates an alternative valve?				
§192.745(c)	Each remote-control valve (RCV) must have a point-to point verification between SCADA system and the valve.				

XL. PART 192 – VALVE DESIGN AND MAINTENANCE: TRANSMISSION		S	N/I	U	N/A
§192.745(d)	For alternative equivalent technology where a valve is manually or locally operated operators much achieve closure in 30 minutes or less through an initial and periodic review. (see code for additional details)				
§192.745(e) & (f)	Each operator must develop and implement remedial measures to correct any valve that is inoperable or unable to maintain effective shutoff. An operator using an ASV as and RMV must document and confirm the ASV shut-in pressures each calendar year not to exceed 15 months. Valves must also be proven to operate each calendar year not to exceed 15 months.				

XLI. PART 192 – VALVE MAINTENANCE: DISTRIBUTION		S	N/I	U	N/A
	Is there a procedure to determine valves that might be used in an emergency?				
§192.181(a)	Each high-pressure distribution system must have 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.				
§192.181(c)	Each valve on a main installed for operating or emergency purposes must comply with the following: (1) The valve must be placed in a readily accessible location so as to facilitate its operation in an emergency. (2) The operating stem or mechanism must be readily accessible. (3) 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.				
§192.747(a)	Does the operator check and service each valve which might be required during an emergency at intervals not exceeding 15 months, but at least once each calendar year?				
§192.747(b)	Does the operator take prompt remedial action to correct any valve found inoperable, unless the operator designates an alternative valve?				

XLII. PART 192 – VAULTS		S	N/I	U	N/A
§192.749(a)	Is each vault that houses pressure regulating and limiting equipment (and has an internal volume of 200 ft^3 or more) inspected at least once each calendar year not exceeding 15 months? **(See records check list)** Vaults need to be inspected to determine if they are in good physical condition and adequately vented. (Vault is defined as “An underground structure which may be entered, and which is designed to contain piping and piping components, such as valves or pressure regulators.”) Currently not aware of any vaults in South Dakota.				
§192.749(b)	If gas was found in vault during inspection was equipment inspected for leaks? If leaks were found were they repaired?				
§192.749(c)	Was ventilating equipment inspected to determine if functioning properly?				

XLII. PART 192 – VAULTS		S	N/I	U	N/A
§192.749(d)	Was vault cover inspected to assure it does not present hazard to public safety?				
§192.727(f)	If any vaults were abandoned, were they filled with a suitable compacted material?				

XLIII. PART 192 – PREVENTION OF ACCIDENTAL IGNITION		S	N/I	U	N/A
§192.751	Does the operator identify steps to minimize the danger of accidental ignition of gas in any structure or area where the presence of gas constitutes a hazard of fire or explosion? Does it include the following: (a) When a hazardous amount of gas is being vented into open air, each potential source of ignition must be removed from the area and a fire extinguisher must be provided. (b) Gas or electric welding or cutting may not be performed on pipe or on pipe components that contain a combustible mixture of gas and air in the area of work. (c) Post warning signs, where appropriate.				

XLIV. PART 192 – GENERAL CONSTRUCTION REQUIREMENTS for TRANSMISSION LINES and MAINS		S	N/I	U	N/A
§192.303 & 192.305	Is it required that each transmission line or main is inspected to ensure that is constructed according to the written procedures? Does the operator have written construction specifications or standards?				

§192.313	**Bends and elbows** (a) Each field bend in *steel pipe* , other than a wrinkle bend made in accordance with §192.315, must comply with the following: (1) A bend must not impair the serviceability of the pipe. (2) Each bend must have a smooth contour and be free from buckling, cracks, or any other mechanical damage. (3) On pipe containing a longitudinal weld, the longitudinal weld must be as near as practicable to the neutral axis of the bend unless: (i) The bend is made with an internal bending mandrel; or (ii) The pipe is 12 inches (305 millimeters) or less in outside diameter or has a diameter to wall *thickness* ratio less than 70. (b) Each circumferential weld of steel pipe which is located where the *stress* during bending causes a permanent deformation in the pipe must be nondestructively tested either before or after the bending process. (c) Wrought- steel welding elbows and transverse segments of these elbows may not be used for changes in direction on steel pipe that is 2 inches (51 millimeters) or more in diameter unless the arc length, as measured along the crotch, is at least 1 inch (25 millimeters). (d) An operator may not install plastic pipe with a bend radius that is less than the minimum bend radius specified by the manufacturer for the diameter of the pipe being installed.				
§192.315	If the operator allows wrinkle bends, are they made in accordance with 192.315?				
§192.317	**Protection from hazards.** (a) The operator must take all practicable steps to protect each transmission line or main from washouts, floods, unstable soil, landslides, or other hazards that may cause the pipeline to move or to sustain abnormal loads. In addition, the operator must take all practicable steps to protect offshore pipelines from damage by mud slides, water currents, hurricanes, ship anchors, and fishing operations				
§192.317	(b) Each above ground transmission line or main must be protected from accidental damage by vehicular traffic or other similar causes, either by being placed at a safe distance from the traffic or by installing barricades.				
§192.319(a)	**Installation of pipe in a ditch** (a) When installed in a ditch, each **transmission** line that is to be operated at a pressure producing a hoop stress of 20 percent or more of SMYS must be installed so that the pipe fits the ditch so as to minimize stresses and protect the pipe coating from damage.				

§192.319(b)	(b) When a ditch for a **transmission line or main** is backfilled, it must be backfilled in a manner that: (1) Provides firm support under the pipe; and (2) Prevents damage to the pipe and pipe coating from equipment or from the backfill material.				
§192.319(d), (e), (f) & (g)	Steel Transmission: After back fill a coating survey must be conducted and any damage classified as severe must be repaired. The coating survey must be documented. (Does not apply to Type B gathering)				
§192.321	**Installation of plastic pipe.** (a) *Plastic pipe* must be installed below ground level except as provided by paragraphs (g), (h) and (i) of this section.				
	(b) Plastic pipe that is installed in a vault or any other below grade enclosure must be completely encased in gas-tight metal pipe and fittings that are adequately protected from corrosion.				
	(c) Plastic pipe must be installed so as to minimize shear or tensile stresses.				
	(d) Plastic pipe must have a minimum wall *thickness* in accordance with § 192.121.				
	(e) Plastic pipe that is not encased must have an electrically conducting wire or other means of locating the pipe while it is underground. Tracer wire may not be wrapped around the pipe and contact with the pipe must be minimized but is not prohibited. Tracer wire or other metallic elements installed for pipe locating purposes must be resistant to corrosion damage, either by use of coated copper wire or by other means.				
	(f) Plastic pipe that is being encased must be inserted into the casing pipe in a manner that will protect the plastic. Plastic pipe that is being encased must be protected from damage at all entrance and all exit points of the casing. The leading end of the plastic must be closed before insertion.				
	(g) Uncased Plastic pipe may be temporarily installed above ground level under the following conditions: (1) The operator must be able to demonstrate that the cumulative aboveground exposure of the pipe does not exceed the manufacturer's recommended maximum period of exposure or 2 years, whichever is less. (2) The pipe either is located where damage by external forces is unlikely or is otherwise protected against such damage. (3) The pipe adequately resists exposure to ultraviolet light and high and low temperatures.				

	(h) Plastic pipe may be installed on bridges provided that it is: (1) Installed with protection from mechanical damage, such as installation in a metallic casing; (2) Protected from ultraviolet radiation; and (3) Not allowed to exceed the pipe *temperature* limits specified in § 192.121. (i) Plastic mains may terminate above ground level provided they comply with the following: (1) The above-ground level part of the plastic main is protected against deterioration and external damage. (2) The plastic main is not used to support external loads. (3) Installations of risers at regulator stations must meet the design requirements of § 192.204.				
§192.323	**Casing.** Each casing used on a transmission line or main under a railroad or highway must comply with the following: (a) The casing must be designed to withstand the superimposed loads.				
	(b) If there is a possibility of water entering the casing, the ends must be sealed.				
	(c) If the ends of an unvented casing are sealed and the sealing is strong enough to retain the maximum allowable operating pressure of the pipe, the casing must be designed to hold this pressure at a stress level of not more than 72 percent of SMYS.				
	(d) If vents are installed on a casing, the vents must be protected from the weather to prevent water from entering the casing.				
§192.325	**Underground clearance.** (a) Each transmission line must be installed with at least 12 inches (305 millimeters) of clearance from any other underground structure not associated with the transmission line. If this clearance cannot be attained, the transmission line must be protected from damage that might result from the proximity of the other structure.				
	(b) Each main must be installed with enough clearance from any other underground structure to allow proper maintenance and to protect against damage that might result from proximity to other structures.				
	(c) In addition to meeting the requirements of paragraphs (a) or (b) of this section, each plastic transmission line or main must be installed with sufficient clearance, or must be insulated, from any source of heat so as to prevent the heat from impairing the serviceability of the pipe.				

<table>
<tr><td></td><td>(d) Each pipe-type or bottle-type holder must be installed with a minimum clearance from any other holder as prescribed in §192.175(b).</td><td></td><td></td><td></td><td></td></tr>
<tr><td>§192.327</td><td>Cover.
(a) Except as provided in paragraphs (c), (e), (f), and (g) of this section, each buried transmission line must be installed with a minimum cover as follows:
<table>
<tr><th rowspan="2">Location</th><th>Normal Soil</th><th>Consolidated Rock</th></tr>
<tr><td colspan="2">Inches (Millimeters)</td></tr>
<tr><td>Class 1 locations</td><td>30 (762)</td><td>18 (457)</td></tr>
<tr><td>Class 2, 3, and 4 locations</td><td>36 (914)</td><td>24 (610)</td></tr>
<tr><td>Drainage ditches of public roads and railroad crossings</td><td>36 (914)</td><td>24 (610)</td></tr>
</table></td><td></td><td></td><td></td><td></td></tr>
<tr><td></td><td>(b) Except as provided in paragraphs (c) and (d) of this section, each buried main must be installed with at least 24 inches (610 millimeters) of cover.</td><td></td><td></td><td></td><td></td></tr>
<tr><td></td><td>(c) Where an underground structure prevents the installation of a transmission line or main with the minimum cover, the transmission line or main may be installed with less cover if it is provided with additional protection to withstand anticipated external loads.</td><td></td><td></td><td></td><td></td></tr>
<tr><td></td><td>(d) A main may be installed with less than 24 inches (610 millimeters) of cover if the law of the State or municipality:
(1) Establishes a minimum cover of less than 24 inches (610 millimeters);
(2) Requires that mains be installed in a common trench with other utility lines; and,
(3) Provides adequately for prevention of damage to the pipe by external forces.
No known laws in SD</td><td></td><td></td><td></td><td>x</td></tr>
<tr><td></td><td>(e) Except as provided in paragraph (c) of this section, all pipe installed in a navigable river, stream, or harbor must be installed with a minimum cover of 48 inches (1,219 millimeters) in soil or 24 inches (610 millimeters) in consolidated rock between the top of the pipe and the underwater natural bottom (as determined by recognized and generally accepted practices).</td><td></td><td></td><td></td><td></td></tr>
</table>

§192.329	**Installation of plastic pipelines by trenchless excavation.** Plastic pipelines installed by trenchless excavation must comply with the following: (a) Each operator must take practicable steps to provide sufficient clearance for installation and maintenance activities from other underground utilities and/or structures at the time of installation. (b) For each pipeline section, plastic pipe and components that are pulled through the ground must use a weak link, as defined by § 192.3, to ensure the pipeline will not be damaged by any excessive forces during the pulling process.				
192 Part C	Does the operator have specifications in place for pipe design?				
§192.144	**Qualifying Metallic components.** Notwithstanding any requirement of this subpart which incorporates by reference an edition of a document listed in §192.7 or Appendix B of this part, a metallic component manufactured in accordance with any other edition of that document is qualified for use under this part if- (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 this part: (1) Pressure testing; (2) Materials; and, (3) Pressure and temperature ratings.				

§192.153	**Components Fabricated by welding** **(**a) 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, must be established in accordance with paragraph UG-101 of the ASME Boiler and Pressure Vessel Code (BPVC) (Section VIII, Division 1) (incorporated by reference, see §192.7). (b) Each prefabricated unit that uses plate and longitudinal seams must be designed, constructed, and tested in accordance with the ASME BPVC (Rules for Construction of Pressure Vessels as defined in either Section VIII, Division 1 or Section VIII, Division 2; incorporated by reference, see §192.7), except for the following: (1) Regularly manufactured butt-welding fittings. (2) Pipe that has been produced and tested under a specification listed in appendix B to this part. (3) Partial assemblies such as split rings or collars. (4) Prefabricated units that the manufacturer certifies have been tested to at least twice the maximum pressure to which they will be subjected under the anticipated operating conditions. (c) Orange-peel bull plugs and orange-peel swages may not be used on pipelines that are to operate at a hoop stress of 20 percent or more of the SMYS of the pipe. (d) Except for flat closures designed in accordance with the ASME BPVC (Section VIII, Division 1 or 2), flat closures and fish tails may not be used on pipe that either operates at 100 p.s.i. (689 kPa) gage or more, or is more than 3 inches in (76 millimeters) nominal diameter. (e) The test requirements for a prefabricated unit or pressure vessel, defined for this paragraph as components with a design pressure established in accordance with paragraph (a) or paragraph (b) of this section are as follows. (1) A prefabricated unit or pressure vessel installed after July 14, 2004 is not subject to the strength testing requirements at §192.505(b) provided the component has been tested in accordance with paragraph (a) or paragraph (b) of this section and with a test factor of at least 1.3 times MAOP.				

	(2) A prefabricated unit or pressure vessel must be tested for a duration specified as follows: (i) A prefabricated unit or pressure vessel installed after July 14, 2004, but before October 1, 2021 is exempt from §§192.505(c) and (d) and 192.507(c) provided it has been tested for a duration consistent with the ASME BPVC requirements referenced in paragraph (a) or (b) of this section. (ii) A prefabricated unit or pressure vessel installed on or after October 1, 2021 must be tested for the duration specified in either §192.505(c) or (d), §192.507(c), or §192.509(a), whichever is applicable for the pipeline in which the component is being installed. (3) For any prefabricated unit or pressure vessel permanently or temporarily installed on a pipeline facility, an operator must either: (i) Test the prefabricated unit or pressure vessel in accordance with this section and Subpart J of this part after it has been placed on its support structure at its final installation location. The test may be performed before or after it has been tied-in to the pipeline. Test records that meet §192.517(a) must be kept for the operational life of the prefabricated unit or pressure vessel; or (ii) For a prefabricated unit or pressure vessel that is pressure tested prior to installation or where a manufacturer's pressure test is used in accordance with paragraph (e) of this section, inspect the prefabricated unit or pressure vessel after it has been placed on its support structure at its final installation location and confirm that the prefabricated unit or pressure vessel was not damaged during any prior operation, transportation, or installation into the pipeline. The inspection procedure and documented inspection must include visual inspection for vessel damage, including, at a minimum, inlets, outlets, and lifting locations. Injurious defects that are an integrity threat may include dents, gouges, bending, corrosion, and cracking. This inspection must be performed prior to operation but may be performed either before or after it has been tied-in to the pipeline. If injurious defects that are an integrity threat are found, the prefabricated unit or pressure vessel must be either non-destructively tested, re-pressure tested, or remediated in accordance with applicable part 192 requirements for a fabricated unit or with the applicable ASME BPVC requirements referenced in paragraphs (a) or (b) of this section. Test, inspection, and repair records for the fabricated unit or pressure vessel must be kept for the operational life of the component. Test records must meet the requirements in §192.517(a).				

	(4) An initial pressure test from the prefabricated unit or pressure vessel manufacturer may be used to meet the requirements of this section with the following conditions: (i) The prefabricated unit or pressure vessel is newly-manufactured and installed on or after October 1, 2021, except as provided in paragraph (e)(4)(ii) of this section. (ii) An initial pressure test from the fabricated unit or pressure vessel manufacturer or other prior test of a new or existing prefabricated unit or pressure vessel may be used for a component that is temporarily installed in a pipeline facility in order to complete a testing, integrity assessment, repair, odorization, or emergency response-related task, including noise or pollution abatement. The temporary component must be promptly removed after that task is completed. If operational and environmental constraints require leaving a temporary prefabricated unit or pressure vessel under this paragraph in place for longer than 30 days, the operator must notify PHMSA and State or local pipeline safety authorities, as applicable, in accordance with §192.18. (iii) The manufacturer's pressure test must meet the minimum requirements of this part; and (iv) The operator inspects and remediates the prefabricated unit or pressure vessel after installation in accordance with paragraph (e)(3)(ii) of this section. (5) An existing prefabricated unit or pressure vessel that is temporarily removed from a pipeline facility to complete a testing, integrity assessment, repair, odorization, or emergency response-related task, including noise or pollution abatement, and then re-installed at the same location must be inspected in accordance with paragraph (e)(3)(ii) of this section; however, a new pressure test is not required provided no damage or threats to the operational integrity of the prefabricated unit or pressure vessel were identified during the inspection and the MAOP of the pipeline is not increased. (6) Except as provided in paragraphs (e)(4)(ii) and (5) of this section, on or after October 1, 2021, an existing prefabricated unit or pressure vessel relocated and operated at a different location must meet the requirements of this part and the following: (i) The prefabricated unit or pressure vessel must be designed and constructed in accordance with the requirements of this part at the				

	time the vessel is returned to operational service at the new location; and (ii) The prefabricated unit or pressure vessel must be pressure tested by the operator in accordance with the testing and inspection requirements of this part applicable to newly installed prefabricated units and pressure vessels.				
§192.157	**Extruded Outlets** If extruded outlets are used are the requirements in 192.157 followed?				
§192.159	**Flexibility** Each pipeline must be 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.				

§192.161	**Supports and anchors** (a) Each pipeline and its associated equipment must have enough anchors or supports to: (1) Prevent undue strain on connected equipment; (2) Resist longitudinal forces caused by a bend or offset in the pipe; and, (3) Prevent or damp out excessive vibration. (b) Each exposed pipeline must have enough supports or anchors to protect the exposed pipe joints from the maximum end force caused by internal pressure and any additional forces caused by temperature expansion or contraction or by the weight of the pipe and its contents. (c) Each support or anchor on an exposed pipeline must be made of durable, noncombustible material and must be designed and installed as follows: (1) Free expansion and contraction of the pipeline between supports or anchors may not be restricted. (2) Provision must be made for the service conditions involved. (3) Movement of the pipeline may not cause disengagement of the support equipment. (d) Each support on an exposed pipeline operated at a stress level of 50 percent or more of SMYS must comply with the following: (1) A structural support may not be welded directly to the pipe. (2) The support must be provided by a member that completely encircles the pipe. (3) If an encircling member is welded to a pipe, the weld must be continuous and cover the entire circumference. (e) Each underground pipeline that is connected to a relatively unyielding line or other fixed object must have enough flexibility to provide for possible movement, or it must have an anchor that will limit the movement of the pipeline. (f) Except for offshore pipelines, each underground pipeline that is being connected to new branches must have a firm foundation for both the header and the branch to prevent detrimental lateral and vertical movement.				
§192.183 /192.185 /192.187 /192.189	**Vault Design Requirement** If a vault is installed, is there a process for the design?				

§192.203	**Instrument, control, and sampling pipe and components.** (a) Applicability. This section applies to the design of instrument, control, and sampling pipe and components. It does not apply to permanently closed systems, such as fluid-filled temperature-responsive devices. (b) Materials and design. All materials employed for pipe and components must be designed to meet the particular conditions of service and the following: (1) Each takeoff connection and attaching boss, fitting, or adapter must be made of suitable material, be able to withstand the maximum service pressure and temperature of the pipe or equipment to which it is attached, and be designed to satisfactorily withstand all stresses without failure by fatigue. (2) Except for takeoff lines that can be isolated from sources of pressure by other valving, a shutoff valve must be installed in each takeoff line as near as practicable to the point of takeoff. Blowdown valves must be installed where necessary. (3) Brass or copper material may not be used for metal temperatures greater than 400(F (204ºC). (4) Pipe or components that may contain liquids must be protected by heating or other means from damage due to freezing. (5) Pipe or components in which liquids may accumulate must have drains or drips. (6) Pipe or components subject to clogging from solids or deposits must have suitable connections for cleaning. (7) The arrangement of pipe, components, and supports must provide safety under anticipated operating stresses. (8) Each joint between sections of pipe, and between pipe and valves or fittings, must be made in a manner suitable for the anticipated pressure and temperature condition. Slip type expansion joints may not be used. Expansion must be allowed for by providing flexibility within the system itself. (9) Each control line must be protected from anticipated causes of damage and must be designed and installed to prevent damage to any one control line from making both the regulator and the over-pressure protective device inoperative.				
§192.65	**Transportation of Pipe – operating 20% SMYS or greater** Are transportation limitations on pipe identified in the procedures?				

XLV. PART 192 – CUSTOMER METERS, SERVICE REGULATORS SERVICE LINES		S	N/I	U	N/A
§192.353	**Customer meters and regulators: Location.** (a) Each meter and service regulator, whether inside or outside a building, must be installed in a readily accessible location and be protected from corrosion and other damage, including, if installed outside a building, vehicular damage that may be anticipated. However, the upstream regulator in a series may be buried.				
	(b) Each service regulator installed within a building must be located as near as practical to the point of service line entrance.				
	(c) Each meter installed within a building must be located in a ventilated place and not less than 3 feet (914 millimeters) from any source of ignition or any source of heat which might damage the meter.				
	(d) Where feasible, the upstream regulator in a series must be located outside the building, unless it is located in a separate metering or regulating building.				
§192.355	**Customer meters and regulators: Protection from damage.** (a) Protection from vacuum or back pressure. If the customer's equipment might create either a vacuum or a back pressure, a device must be installed to protect the system. (necessary when a supplement gas used for stand-by)				
	(b) Service regulator vents and relief vents. Service regulator vents and relief vents must terminate outdoors, and the outdoor terminal must: (1) Be rain and insect resistant; (2) Be located at a place where gas from the vent can escape freely into the atmosphere and away from any opening into the building; and, (3) Be protected from damage caused by submergence in areas where flooding may occur.				
	(c) Pits and vaults. Each pit or vault that houses a customer meter or regulator at a place where vehicular traffic is anticipated, must be able to support that traffic.				
§192.357	**Customer meters and regulators: Installation.** (a) Each meter and each regulator must be installed so as to minimize anticipated stresses upon the connecting piping and the meter.				
	(b) When close all-thread nipples are used, the wall thickness remaining after the threads are cut must meet the minimum wall thickness requirements of this part.				
	(c) Connections made of lead or other easily damaged material may not be used in the installation of meters or regulators.				
	(d) Each regulator that might release gas in its operation must be vented to the outside atmosphere.				

§192.359	**Customer meter installations: Operating pressure.** (a) A meter may not be used at a pressure that is more than 67 percent of the manufacturer's shell test pressure. (b) Each newly installed meter manufactured after November 12, 1970, must have been tested to a minimum of 10 p.s.i. (69 kPa) gage. (c) A rebuilt or repaired tinned steel case meter may not be used at a pressure that is more than 50 percent of the pressure used to test the meter after rebuilding or repairing.				
§192.361	**Service lines: Installation.** (a) Depth. Each buried service line must be installed with at least 12 inches(305 millimeters) of cover in private property and at least 18 inches (457 millimeters) of cover in streets and roads. However, where an underground structure prevents installation at those depths, the service line must be able to withstand any anticipated external load.				
	(b) Support and backfill. Each service line must be properly supported on undisturbed or well-compacted soil, and material used for backfill must be free of materials that could damage the pipe or its coating.				
	(c) Grading for drainage. Where condensate in the gas might cause interruption in the gas supply to the customer, the service line must be graded so as to drain into the main or into drips at the low points in the service line.				
	(d) Protection against piping strain and external loading. Each service line must be installed so as to minimize anticipated piping strain and external loading.				
	(e) Installation of service lines into buildings. Each underground service line installed below grade through the outer foundation wall of a building must: (1) In the case of a metal service line, be protected against corrosion; (2) In the case of a plastic service line, be protected from shearing action and backfill settlement; and (3) Be sealed at the foundation wall to prevent leakage into the building.				

	(f) Installation of service lines under buildings. Where an underground service line is installed under a building: (1) It must be encased in a gas-tight conduit; (2) The conduit and the service line must, if the service line supplies the building it underlies, extend into a normally usable and accessible part of the building; and, (3) The space between the conduit and the service line must be sealed to prevent gas leakage into the building and, if the conduit is sealed at both ends, a vent line from the annular space must extend to a point where gas would not be a hazard, and extend above grade, terminating in a rain and insect resistant fitting.				
	(g) Locating underground service lines. Each underground nonmetallic service line that is not encased must have a means of locating the pipe that complies with §192.321(e).				
§192.363	**Service lines: Valve Requirements.** (a) Each service line must have a service-line valve that meets the applicable requirements of Subparts B and D of this part. A valve incorporated in a meter bar, that allows the meter to be bypassed, may not be used as a service-line valve.				
	(b) A soft seat service line valve may not be used if its ability to control the flow of gas could be adversely affected by exposure to anticipated heat.				
	(c) Each service-line valve on a high-pressure service line, installed aboveground or in an area where the blowing of gas would be hazardous, must be designed and constructed to minimize the possibility of the removal of the core of the valve with other than specialized tools.				
§192.365	**Service lines: Location of valves.** (a) Relation to regulator or meter. Each service-line valve must be installed upstream of the regulator or, if there is no regulator, upstream of the meter.				
	(b) Outside valves. Each service line must have a shutoff valve in a readily accessible location that, if feasible, is outside of the building.				
	(c) Underground valves. Each underground service-line valve must be located in a covered durable curb box or standpipe that allows ready operation of the valve and is supported independently of the service lines.				
§192.367	**Service lines: General requirements for connections to main piping** (a) Location. Each service line connection to a main must be 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) Compression-type connection to main. Each compression-type service line to main connection must: (1) 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; (2) 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 (3) If used on pipelines comprised of plastic, be a Category 1 connection as defined by a *listed specification* for the applicable material, providing a seal plus resistance to a force on the pipe joint equal to or greater than that which will cause no less than 25% elongation of pipe, or the pipe fails outside the joint area if tested in accordance with the applicable standard.				
§192.371	**Service lines: Steel.** Each steel service line to be operated at less than 100 p.s.i. (689 kPa) gage must be constructed of pipe designed for a minimum of 100 p.s.i. (689 kPa) gage.				
§192.375	**Service lines: Plastic.** (a) Each plastic service line outside a building must be installed below ground level, except that - (1) It may be installed in accordance with §192.321(g); and (2) It may terminate above ground level and outside the building, if- (i) The above ground level part of the plastic service line is protected against deterioration and external damage; and (ii) The plastic service line is not used to support external loads; and (iii) The riser portion of the service line meets the design requirements of § 192.204 (b) Each plastic service line inside a building must be protected against external damage.				
§192.376	**Installation of plastic service lines by trenchless excavation.** Plastic service lines installed by trenchless excavation must comply with the following: (a) Each operator shall take practicable steps to provide sufficient clearance for installation and maintenance activities from other underground utilities and structures at the time of installation. (b) For each pipeline section, plastic pipe and components that are pulled through the ground must use a weak link, as defined by § 192.3, to ensure the pipeline will not be damaged by any excessive forces during the pulling process.				

§192.379	**New service lines not in use.** Each service line that is not placed in service upon completion of installation must 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 must be provided with a locking device or other means designed to prevent the opening of the valve by persons other than those authorized by the operator. (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.				