PIPELINE SAFETY O&M MANUAL CHECKLIST

2016

South Dakota Public Utilities Commission

GENERAL INFORMATION			
Operator Evaluated			
Operator OPID (191.22)			
Inspection Unit IOCS ID			
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)		**Phone Number**	
Responsible Party/Title		**Phone Number**	
Mailing Address			
Inspection Date		**Last Inspection Date**	
Location of Inspection			
Inspector Name			

I. Recent Rule Changes		S	N/I	U	N/A
Has the operator made changes to the following items from the Federal Register/Vol. 80 No. 2/ Monday, January 5, 2015 (effective March 6, 2015) including:					
§192.7	Has the operator updated the reference documents?				
§192.59	Has the operator ensured that rework is not allowed for plastic pipe manufacturers?				
§192.63	Has the operator updated the requirements for marking materials?				
§192.65	Has the operator updated the requirement for transportation of material in a pipeline operating at 20% or more of SMYS? (truck) **(Transmission)**				
§192.123	Has the operator identified that design limits for plastic pipe must be in accordance with ASTM D2513-09a?				
§192.191	Has the operator updated the design pressure for polyethylene fittings to conform with ASTM D2513-09a?				
Has the operator made the changes from the Federal Register / Vol. 80 No. 47 / March 11, 2015 (effective October 1, 2015) including:					
§191.7(a), (b), &	Has the operator updated the report submission requirements and				

I. Recent Rule Changes		S	N/I	U	N/A
(e)	added the NPMS reporting requirements? **(Transmission.)**				
§191.25	Has the operator updated the requirements for filing safety related conditions?				
§191.29	Has the operator added the requirements of the National Pipeline Mapping System? **(Transmission.)**				
§192.3	Has the operator updated the definition of a welder?				
§192.65	Has the operator updated the requirement for transportation of material in a pipeline operating at 20% or more of SMYS? (railroad) **(Transmission)**				
§192.225	Has the operator updated the welding procedure and reference to API 1104 or section IX ASME Boiler and Pressure Vessel Code?				
§192.227	Has the operator included qualification of a welding operator as well as a welder?				
§192.229	Has the operator included limitations of a welding operator as well as a welder?				
§192.241(c)	Has the operator revised inspections of welds as required (cracks)?				
§192.243(e)	Has the operator revised non-destructive testing as required (welder operator)?				
§192.285	Has the operator revised qualifying persons to make joints as required? (plastic fusion)				
	How does this affect waiver (if you have one)?				
§192.503(e)	Has the operator incorporated the rule regarding general requirements of testing of a component other than pipe? (Item also included in section XVII below.) (moved from 192.505 to 192.503)				
§192.505(d) and (e)	Has the operator incorporated the new rule regarding testing requirements? (Paragraph (d) is removed.) **(Transmission)** (Item also included in section XVII below.)				
§192.805 OQ Plan	Is the operator aware of the notification required when making changes to the qualifications program notification?				

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) 4. Distribution system annual reports (191.11) 5. Distribution system mechanical fitting failure reports (191.12) 6. Transmission and gather system incident report (191.15 7. Transmission system annual report (191.17) 8. Notification of changes per 191.22 (c) 9. Reporting safety related conditions (191.23) 10. Filling safety – related condition reports (191.25)				
191.7 & 191.29	Do you have a procedure to ensure that changes to the transmission system are updated in NPMS?				

III. PART 192 – OPERATION & MAINTENANCE PLANS		S	N/I	U	N/A

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.						

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.						

IV. PART 192 – EMERGENCY PLANS		S	N/I	U	N/A
	(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.				
	(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) 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 fire, police, and other public officials of gas pipeline emergencies and coordinating with them both planned responses and actual responses during an emergency.				
	(9) Safely restoring any service outage.				
	(10) Beginning action under §192.617, 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.				
§192.615(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:				
§192.615(b)(2)	Is there a requirement to train appropriate employees as to the requirements of the emergency plan.				
§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?				

IV. PART 192 – EMERGENCY PLANS		S	N/I	U	N/A
§192.615(c)	Establish mutual liaison with fire, police, and other public officials, such that each is aware of the others resources and capabilities in dealing with gas emergencies.				
	(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 – 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?				

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)				

VI. PART 192 – WELDING		S	N/I	U	N/A
	- Nick-break test information (and any remarks on nick-break test)				
	- 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)?				
§192.229(b)	Does operator maintain records for each qualified welder that show the welder has engaged in a specific welding process (for welders that qualify under 192.227(a)?				
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?				
	(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)	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				
§192.241(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(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		V	N/I	U	N/A
	The operator has the following material types in their system: steel, plastic, cast iron, ductile iron, copper				

VIII. PART 192 – JOINING OF PIPELINE MATERIALS OTHER THAN BY WELDING		V	N/I	U	N/A
	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.				
§192.281(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 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 piping, compresses the heated ends together, and holds the pipe in proper alignment while the plastic hardens;				
	(2) A socket heat-fusion joint must be joined by a device that heats the mating surfaces of the joint uniformly and simultaneously to essentially the same temperature;				
	(3) An electrofusion joint must be joined utilizing the equipment and techniques of the fittings manufacturer or equipment and techniques shown, by testing joints to the requirements of §192.283(a)(1)(iii), to be at least equivalent to those of the fittings 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.				
§192.283	**Plastic Pipe**				

VIII. PART 192 – JOINING OF PIPELINE MATERIALS OTHER THAN BY WELDING		V	N/I	U	N/A
	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)				
	Does operator have copies of the destructive tests used to qualify the joining procedures? (yes or no)				
§192.285(a)(1) §192.285(a)(2) and §192.285(c)	**Plastic Pipe**				
	Does operator maintain records of employee training dates and type of join training for each employee? (yes or no)				
§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?				

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(b)	Do the EFV valves meet the applicable requirements of Subparts B and D?				
§192.381(c)	Does the operator mark or otherwise identify the presence of an excess flow valve on a 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)	Does operator not install EFV on a service line where operator has prior experience with contaminants in gas stream where contaminants could cause EFV to malfunction or where EFV would interfere with necessary O&M activities, such as blowing liquids from the line?				

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: Are there any pipelines without cathodic protection?				
	(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				

XII. PART 192 – EXTERNAL CORROSION CONTROL		S	N/I	U	N/A
§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?				
§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:				
	(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?				

XII. PART 192 – EXTERNAL CORROSION CONTROL		S	N/I	U	N/A
§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?				
§192.463 (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-$CuSO_4$ 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				
§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?				

XII. PART 192 – EXTERNAL CORROSION CONTROL		S	N/I	U	N/A
§192.465(d)	Is prompt remedial action taken to correct any deficiencies indicated by the monitoring?				
	(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?				
§192.467	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.				
	(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?				

XII. PART 192 – EXTERNAL CORROSION CONTROL		S	N/I	U	N/A
	(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?				

XIII. PART 192 – INTERNAL CORROSION CONTROL		S	N/I	U	N/A
§192.475(a)	Is gas tested to determine 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	Have coupons **(for corrosive gas only)** been utilized & checked at least **twice** annually not to exceed **7-1/2** months?				

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)	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?				
§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 ASME/ANSI B31G or AGA PR 3-805				
§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?				
§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?				

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?				
§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?				

XVII. PART 192 – TEST REQUIREMENTS FOR PIPELINES		S	N/I	U	N/A

XVII. PART 192 – TEST REQUIREMENTS FOR PIPELINES		S	N/I	U	N/A
§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) compontent 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.				
	Steel Pipelines Operating at greater than or equal to 30% SMYS				
192.505(a)	*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(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?				
§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)				
192.509 and 192.517	**For pipelines (except plastic and service) to operate below 100 psig.**				
	Are pressure test records maintained that contain the following information (these records must be maintained for at least 5 years):				

XVII. PART 192 – TEST REQUIREMENTS FOR PIPELINES		S	N/I	U	N/A
	- Date				
	- Location of test				
	- Test pressure applied				
	- Test duration				
	- The operator's name & the name of the employee responsible				
	- Test medium used.				
	- Pressure recording charts, or other record of pressure readings.				
	- Elevation variations, whenever significant for the particular test.				
	- Leaks and failures noted and their disposition.				
§192.509(b)	Is each main that is to be operated at less than 1 psig tested to at least 10 psig? (yes or no)				
§192.509(b)	Is each main that is to be operated at or above 1 psig tested to at least 90 psig? (yes or no)				
192.511 and 192.517	**For non-plastic service lines.**				
	Are pressure test records maintained that contain the following information (these records must be maintained for at least 5 years):				
	- Date				
	- Location of test				
	- Test pressure applied				
	- Test duration				
	- The operator's name & the name of the employee responsible				
	- Test medium used.				
	- Pressure recording charts, or other record of pressure readings.				
	- Elevation variations, whenever significant for the particular test.				
	- Leaks and failures noted and their disposition.				
§192.511(a)	If feasible, is the connection to the main 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 tested at a pressure of not less than 50 psig? (yes or no)				
§192.511(c)	Are service lines expected to operate at a pressure of more than 40 psig tested at a pressure of not less than 90 psig? (yes or no)				
§192.511(c)	Are steel service lines stressed to 20% or more of SMYS tested in accordance with §192.507?				
192.513 and 192.517	**For plastic pipelines.**				
	Are pressure test records maintained that contain the following information (these records must be maintained for at least 5 years):				
	- Date				
	- Location of test				
	- Test pressure applied				
	- Test duration				
	- The operator's name & the name of the employee responsible				
	- Test medium used.				
	- Pressure recording charts, or other record of pressure readings.				
	- Elevation variations, whenever significant for the particular test.				
	- Leaks and failures noted and their disposition.				

XVII. PART 192 – TEST REQUIREMENTS FOR PIPELINES		S	N/I	U	N/A
§192.513(c)	Does the operator test to at least **150%** of the maximum operating pressure or **50 psig** whichever is greater? (yes or no and list out which one is greater for each operator)				
§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)				

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?				
§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).)				

XVIII. PART 192 – UPRATING		S	N/I	U	N/A
§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).				
	(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.				

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?				

XXI. PART 192 – CHANGE IN CLASS LOCATION		S	N/I	U	N/A
§192.611	What does the operator alter when population density requires a change in MAOP? (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.				
	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?				

XXIII. PART 192 – DAMAGE PREVENTION		S	N/I	U	N/A
	Does the operator have a damage prevention program?				
	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?				

XXIV. PART 192 – FAILURE INVESTIGATION		S	N/I	U	N/A

§192.617	Does the operator have a procedure for failure investigations?				
	Is the analysis documented?				

XXV. PART 192 – MAXIMUM ALLOWABLE OPERATING PRESSURE		S	N/I	U	N/A
	Does the operator determine MAOP correctly?				
§192.619/.621 §192.623	Is the MAOP commensurate with the class location?				
	How is the MAOP determined? (a) By design and test?				
	(b) By highest operating pressure to which the segment of line was subjected between July 1, 1965 and July 1, 1970.				

XXVI. PART 192 – ODORIZATION OF GAS		S	N/I	U	N/A
	Detectable at one-fifth of the lower explosive limit. Equipment used? Odorometer, Odorator,				
	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?				

XXVII. PART 192 – HOT TAPPING		S	N/I	U	N/A
§192.627	Are hot taps made by qualified personnel?				
	Do they **Non-Destructive Test** tap area? (API RP 2201)				

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?				
§192.703(c)	Are hazardous leaks repaired promptly?				

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?				

XXX. PART 192 – PATROLLING TRANSMISSION			S	N/I	U	N/A
§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?				
	(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:				
	(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				

XXXIII. PART 192 – FIELD REPAIRS: TRANSMISSION LINES		S	N/I	U	N/A
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).*				
§192.711(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.				
§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.				
§192.713(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.				
§192.715	Is each weld found not acceptable under 192.241(c) repaired properly?				
§192.717	Do weld repairs meet the following?				

XXXIII. PART 192 – FIELD REPAIRS: TRANSMISSION LINES		S	N/I	U	N/A
	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)*				

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?				

XXXV. PART 192 – LEAKAGE SURVEYS: DISTRIBUTION		S	N/I	U	N/A
§192.605(b)	Procedures for §192.723?				
§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?				

XXXV. PART 192 – LEAKAGE SURVEYS: DISTRIBUTION		S	N/I	U	N/A
§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.				
§192.739(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?				

XXXVIII. PART 192 – PRESSURE LIMITING AND REGULATING STATIONS		S	N/I	U	N/A
§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.				
§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?				

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 MAINTENANCE: TRANSMISSION		S	N/I	U	N/A

XL. PART 192 – VALVE MAINTENANCE: TRANSMISSION		S	N/I	U	N/A
§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.				
§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?				

XLI. PART 192 – VALVE MAINTENANCE: DISTRIBUTION		S	N/I	U	N/A
§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.				

XLI. PART 192 – VALVE MAINTENANCE: DISTRIBUTION		S	N/I	U	N/A
§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 No vaults exist in South Dakota		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.				**x**
§192.749(b)	If gas was found in vault during inspection was equipment inspected for leaks? If leaks were found were they repaired?				**x**
§192.749(c)	Was ventilating equipment inspected to determine if functioning properly?				**x**
§192.749(d)	Was vault cover inspected to assure it does not present hazard to public safety?				**x**
§192.727(f)	If any vaults were abandoned, were they filled with a suitable compacted material?				**x**

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
§192.317	**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.				
§192.321	**Installation of plastic pipe.** (a) Plastic pipe must be installed below ground level except as provided by paragraphs (g) and (h) 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) Thermoplastic pipe that is not encased must have a minimum wall thickness of 0.090 inch (2.29 millimeters), except that pipe with an outside diameter of 0.875 inch (22.3 millimeters) or less may have a minimum wall thickness of 0.062 inch(1.58 millimeters).				
	(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. 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 §192.123.				
§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.				

<table>
<tr><td></td><td>(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.</td><td></td><td></td><td></td><td></td></tr>
<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>

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 pullout or thrust forces caused by contraction or expansion of the piping, or by anticipated external or internal loading; and (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.				
§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. (b) Each plastic service line inside a building must be protected against external damage.				
§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.				