PIPELINE SAFETY O&M MANUAL CHECKLIST

2013

South Dakota Public Utilities Commission

I. 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			

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)								
§191.5		Have any incident(s) occurred within the last **2 calendar years** (yes or no)?								
		Were incident(s) telephonically or electronically reported to **NRC**? **(1-800-424-8802)**								
Info required to be reported by	*Date reported to NRC*	*Name of person reporting*	*Location*	*Time of incident*	*# of fatalities/ injuries*	*Comments*				

<table>
<tr><th colspan="5">II. PART 191 – REPORTING REQUIREMENTS</th><th>S</th><th>N/I</th><th>U</th><th>N/A</th></tr>
<tr><td>telephone:</td><td colspan="4"></td><td></td><td></td><td></td><td></td></tr>
<tr><td></td><td colspan="4">Was all required information reported to NRC?</td><td></td><td></td><td></td><td></td></tr>
<tr><td rowspan="6">§191.9 and §191.15</td><td colspan="4">Are incidents reported under §191.5 followed up with a 30-day written report? (RSPA Form 7100.1) – Distribution or (RSPA Form 7100.2) – Transmission and Gathering</td><td></td><td></td><td></td><td></td></tr>
<tr><td>Type of form submitted to PHMSA</td><td>Date submitted to PHMSA</td><td>Copy available in facility's records</td><td>Form is filled out with all required info</td><td></td><td></td><td></td><td></td></tr>
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<tr><td colspan="4">Was additional relevant information submitted as a supplementary report (if necessary)?</td><td></td><td></td><td></td><td></td></tr>
<tr><td rowspan="3">§191.11; §191.17; and
ARSD 20:10:37:10</td><td colspan="4">Are annual reports submitted to Washington and the SDPUC? (PHMSA F 7100.1-1) – Distribution Systems or (PHSMA F 7100.2-1) – Transmission and Gathering Systems</td><td></td><td></td><td></td><td></td></tr>
<tr><td>Type of form submitted to PHMSA</td><td>Date most recent submitted to PHMSA</td><td>Copy available in facility's records</td><td>Form is filled out with all required info</td><td></td><td></td><td></td><td></td></tr>
<tr><td></td><td></td><td></td><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td>§191.12</td><td colspan="4">Are mechanical fittings reported as required by § 192.1009, on a Mechanical Fitting Failure Report Form PHMSA F- 7100.1-2?</td><td></td><td></td><td></td><td></td></tr>
<tr><td>§191.22(a) &
§191.22(b)</td><td colspan="4">Has an operator ID been obtained or verified? (OPID)</td><td></td><td></td><td></td><td></td></tr>
<tr><td rowspan="3">§191.22(c)</td><td colspan="4">Have changes been electronically submitted for the following?</td><td></td><td></td><td></td><td></td></tr>
<tr><td colspan="4">Notify PHMSA of any of the following events not later than 60 days before the event occurs:

A. Construction or any planned rehabilitation, replacement, modification, upgrade, uprate, or update of a facility, other than a section of line pipe, that costs $10 million or more.
B. Construction of 10 or more miles of a new pipeline; or
C. Construction of a new LNG plant or LNG facility.</td><td></td><td></td><td></td><td></td></tr>
<tr><td colspan="4">Notify PHMSA of any of the following events not later than 60 days after the event occurs:

A. A change in the primary entity responsible (i.e., with an assigned OPID) for managing or administering a safety program required by this part covering pipeline facilities operated under multiple OPIDs.
B. A change in the name of the operator;
C. A change in the entity (e.g., company, municipality) responsible for an existing pipeline, pipeline segment, pipeline facility, or LNG facility;
D. The acquisition or divestiture of 50 or more miles of a pipeline or pipeline system subject to Part 192 of this subchapter; or
E. The acquisition or divestiture of an existing LNG plant or LNG facility subject to Part 193 of this subchapter.</td><td></td><td></td><td></td><td></td></tr>
<tr><td rowspan="3">§191.23</td><td colspan="4">Does the facility have a procedure for reporting safety related conditions?</td><td></td><td></td><td></td><td></td></tr>
<tr><td colspan="4">(a) Did any of the following safety related conditions occur within the last <u>2</u> calendar years:</td><td></td><td></td><td></td><td></td></tr>
<tr><td colspan="4">General corrosion that reduced wall thickness to less than required for the MAOP or localized corrosion pitting where leaks may occur (for pipelines operating at 20% or more of</td><td></td><td></td><td></td><td></td></tr>
</table>

II. PART 191 – REPORTING REQUIREMENTS		S	N/I	U	N/A
	SMYS, i.e. transmission lines)				
	Unintended movement or abnormal loading by environmental causes that impairs the serviceability of the pipeline				
	Any crack or other material defect that impairs the structural integrity of a LNG facility that contains controls or process gas or LNG				
	Any **material defect or physical damage** that impairs the serviceability of pipelines that operate at 20% or more of SMYS (transmission lines)				
	Any **malfunction or operating error** that causes the MAOP to be exceeded (plus the allowed build up for pressure limiting devices)				
	A **leak** in a pipeline or LNG facility that constitutes an emergency				
	Inner tank leakage, ineffective insulation, or frost heave that impairs the structural integrity of a LNG storage tank				
	Any **safety-related condition** that could lead to an imminent hazard and causes a reduction in operating pressure (by 20% or more) or shutdown of a pipeline				
§191.23(b)	*NOTE: reports are not required for: 1) master meter systems or customer-owned service lines; 2) incidents or conditions that result in an incident before the deadline for filing the report; 3) pipelines that are more than 220 yards from occupied buildings or outdoor places of assembly (except they are required in railroad and road ROWs); and 4) if the condition is corrected by repair or replacement before the deadline for filing the report (except they are required for general corrosion conditions)*				
§191.25	(a) Was a report filed within five (**5**) working days of determination and within ten (**10**) working days of discovery for each safety-related condition?				

Safety-related condition discovered	*Discovery date*	*Determination date*	*Date reported to PHMSA*	*Copy included in facility's records*				
	Was all required information included in the "Safety-Related Condition Report" (refer to 191.25(b))?							

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**:						

		S	N/I	U	N/A
§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				

III. PART 192 – OPERATION & MAINTENANCE PLANS						S	N/I	U	N/A
	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 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?								
	Review date	*Type of review*	*Personnel reviewed*	*Documented in records*					
§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.							
	(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.							

IV. PART 192 – EMERGENCY PLANS		S	N/I	U	N/A
	(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.				
§192.605(b)(11)	Does there operator have a plan for responding promptly to a report of a gas odor inside or near a building?				
§192.615(a)(3)	**Does the emergency response procedures for leaks caused by excavation damage near buildings** **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)	(a) 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)	(b) Training appropriate employees as to the requirements of the emergency plan.				

Training Date	*Persons Trained*	*Comments*

		S	N/I	U	N/A
§192.615(b)(3)	(c) 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?				
§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				

IV. PART 192 – EMERGENCY PLANS		S	N/I	U	N/A
	(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	Has the operator notified 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?				
§192.16 (b)	Does the operator have a current copy of the notification?				
	Does notification contain all the following requirements:				
	(1) operator does not maintain the customer’s buried piping				
	(2) if customer’s buried piping is not maintained, it may be subject to corrosion and leakage				
	(3) buried gas piping should be: (i) periodically inspected for leaks				
	(ii) periodically inspected for corrosion (if metal pipe)				
	(iii) repaired if any unsafe condition is discovered				
	(4) when excavating near buried gas piping, the piping should be located in advance, and the excavation done by hand				
	(5) the operator, plumbing contractors, and heating contractors can assist in locating, inspecting, and repairing the customer’s buried piping				

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.				
§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)				

VI. PART 192 – WELDING		S	N/I	U	N/A
§192.241(c)	Is a weld that is nondestructively tested or visually inspected determined according to the standards in Section 9 of API Standard 1104?				
§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				
	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.				
192.283	**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		V	N/I	U	N/A
	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 have copies of employee training dates and type of join training for each employee? (yes or no)				
	Does operator have copies of employee making specimen joints from pipe sections joined according to the procedure that passes inspection and test as set forth in 192.285(b)?				
	Does the operator maintain records of each employee's requalification? (yes or no) Is the requalification done as required and documented within their records (if employees do not make a joint during a 12 month period or if 3 joints or 3%, whichever is greater, are found unacceptable then they must be requalified)? (yes or no) *Note: be sure to see if operator has applied for and obtained a waiver on this issue and make sure they are following the waiver requirements.*				
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	The operator's procedures should be inspected in the field to determine if they are being followed. 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 ≥ 10 psi) manufactured and tested to an industry standard or manufacturer's written specification to ensure each valve will:				
§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 ≤ 50 % above the rated closure flow specified by manufacturer; AND				

X. PART 192 – EXCESS FLOW VALVES		S	N/I	U	N/A
§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?				
§192.383(b)	Has the operator installed § 192.381 compliant EFV's on all new or replaced service line serving a single-family residence after February 12, 2010? Exceptions: (1) The service line does not operate at a pressure 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 residence; (3) An EFV could interfere with necessary operation or maintenance activities, such as blowing liquids from the line; or (4) An EFV meeting performance standards in § 192.381 is not commercially available to the operator.				
§192.383(c)	Does the annual report contain the number of EFV's installed?				

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?				

XII. PART 192 – EXTERNAL CORROSION CONTROL		S	N/I	U	N/A
	(2) Conducted tests within 6-months to confirm (#1) above?				
§192.455	**Pipeline Material Types:** What kinds of pipeline materials are used? Steel, Copper, Aluminum, Plastic, Cast Iron, 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?				
§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?				
	Does operator have procedures established for remedial measures on **cast iron** pipe if graphitization is discovered, AGA GPTC Appendix G-18 (NTSB)?				
§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?				
§192.463 (a)	Does the level of cathodic protection meet the requirements of Appendix D criteria?				

XII. PART 192 – EXTERNAL CORROSION CONTROL		S	N/I	U	N/A
Appendix D	Steel, cast iron, and ductile iron				
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				
§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:				
	(1) electrically isolated from the remainder of the pipeline and cathodically protected?; OR				
	(2) cathodically protected at a level that meets the requirements of Appendix D for amphoteric metals?				
§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?				
	(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?				

XII. PART 192 – EXTERNAL CORROSION CONTROL		S	N/I	U	N/A
	(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(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?				
Service lines	(1) Is operator cathodically protecting service lines				
	(a) Operator owned piping/downstream of meter				
	(b) Operator owned piping/upstream of meter				
	(c) Customer owned piping/downstream of meter				
	(d) Customer owned piping/upstream of meter				
	(2) Is operator monitoring unprotected service lines				
	(a) Operator owned piping/downstream of meter				
	(b) Operator owned piping/upstream of meter				
	(c) Customer owned piping/downstream of meter				
	(d) Customer owned piping/upstream of meter				
	(3) How is monitoring performed on unprotected services				
	(a) Electrical Survey: Type				
	Frequency				

XII. PART 192 – EXTERNAL CORROSION CONTROL		S	N/I	U	N/A
	(b) Leak Survey: Type				
	Frequency				
	(4) Is there a program in effect to address corrosion problems on service lines				
	Describe:				

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?				
§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?				

XIV. PART 192 – ATMOSPHERIC CORROSION CONTROL		S	N/I	U	N/A
§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
§192.503	Have any new segments of pipeline been installed or segments of relocated or replaced pipeline been returned to service (yes or no)?				
	Have the following criteria been met?				
§192.503(a)	(1) It has been tested in accordance with this subpart and §192.619 to substantiate the maximum allowable operating pressure;				
	(2) Each potentially hazardous leak has been located and eliminated.				
§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.				

XVII. PART 192 – TEST REQUIREMENTS FOR PIPELINES		S	N/I	U	N/A
§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)				
	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(b)	Have any compressor, regulator, or measuring stations been newly installed or replaced in Class 1 and Class 2 locations? (yes or no) If yes, were they tested to at least Class 3 location requirements?				
§192.505(c)	Is the pressure at or above test pressure for at least eight hours? (yes or no)				
§192.505(d) §192.505(d)(1) §192.505(d)(2) §192.505(d)(3)	If only components were added or replaced (not pipe) and not pressure tested: Does facility have manufacturer certification of at least one of the following: - component was tested to the pressure required for the pipeline to which it is being added; - component was manufactured under a quality control system that ensures each item is at least equal in strength to a prototype and the prototype was tested to a test pressure required for the pipeline to which it is being added; or - component carries a pressure rating established through applicable ASME/ANSI, MSS specifications, or by unit strength calculations as described in §192.143. List or highlight which certification the facility has within its records.				
§192.505(e)	Were any fabricated or short sections of pipe installed? (yes or no) If yes were these sections pressure tested for at least four hours before they are installed, if it is impractical to pressure test after installation? (yes or no)				
§192.507(b)(1) §192.507(b)(2)	**Pipelines Operating at less than 30 percent of SMYS and at or above 100 psig.**				
	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.				
§192.513(a)	Is each segment of a plastic pipeline tested in accordance with this section? (yes or no)				
§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).)				

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
§192.605(c)	(Does not apply to distribution operators that also operate transmission lines.) Has the operator had any occurrences of the following conditions in the last 2 years (yes or no): - Unintended closure of valves or shutdowns - An increase or decrease in pressure or flow rate outside of normal operating limits - Loss of communications - The operation of any safety device - Any other malfunction of a component - Any deviation from normal operation - Any other foreseeable malfunction of a component, deviation from normal operation, or personnel error List out what type and date of occurrence.				

XX. PART 192 – ABNORMAL OPERATIONS: TRANSMISSION LINES		S	N/I	U	N/A
§192.605(c)(4)	If abnormal operation occurred, did operator review personnel response considering the actions taken, whether procedures were followed, and whether procedures were adequate or should be revised? Was this review documented?				

XXI. PART 192 – CHANGE IN CLASS LOCATION		S	N/I	U	N/A
§192.605(b)	Procedures for §192.611?				
§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.				
	(c) Replace pipe.				
	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
§192.614	Does the operator have a list of persons/companies that engage in excavating? (yes or no)				
192.617	Does operator maintain records of accidents and failures and their causes?				
	Has operator addressed the causes of failure to minimize the possibility of recurrence?				
	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?				
	Did the operator follow its written procedures pertaining to notification of excavation, marking, positive response and the use of the one call system?				
	What is the operator’s number of pipeline damages per 1,000 locate requests?				

XXIV. PART 192 – FAILURE INVESTIGATION		S	N/I	U	N/A
§192.617	Have any accidents or failures occurred within the past 2 years? *If yes, give explanation.*				
	If yes, was the accident and/or failure analyzed to determine the cause and steps taken to minimize a recurrence? Was the analysis documented?				

XXV. PART 192 – MAXIMUM ALLOWABLE OPERATING PRESSURE		S	N/I	U	N/A
§192.619/.621 §192.623	Is the MAOP commensurate with the class location? **(Spot check calculations)**				
	How was 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.				
	Were MAOP's determined correctly?				

SYSTEM	Initial Operation Month/yr.	Highest Pressure Test	Highest Operating Pressure	MAOP	Limiting Basis

NOTES:

§192.505	Strength test requirements for steel pipeline to operate at a hoop stress of 30 percent or more of SMYS.
§192.507	Test requirements for steel pipeline to operate at a hoop stress less than 30 percent or more of SMYS and at or above 100 psig.
§192.509	Test requirements for pipelines to operate below 100 psig.

XXVI. PART 192 – ODORIZATION OF GAS		S	N/I	U	N/A
§192.605(b)	Procedures for §192.625?				
§192.625(a)	Chemical Properties - Brand Name –				
	Detectable at one-fifth of the lower explosive limit. Equipment used? Odorometer, Odorator,				
	Injection Rate				
	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 – TAPPING PIPELINES UNDER PRESSURE		S	N/I	U	N/A
§192.605(b)	Procedures for §192.627?				
§192.627	Are hot taps made by qualified personnel? **(See records check list)**				
	Qualifier: Do they **Non-Destructive Test** tap area?				

XXVIII. PART 192 – PIPELINE PURGING		S	N/I	U	N/A
§192.605(b)	Procedures for §192.629?				
§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)?				
§192.727(e)	If air is used for purging, is the operator insuring that a combustible mixture is not present after purging?				

XXIX. PART 192 – MAINTENANCE		S	N/I	U	N/A

XXIX. PART 192 – MAINTENANCE		S	N/I	U	N/A
§192.605(b)	Procedures for §192.703?				
§192.703(b)	Is each segment of a pipeline that becomes unsafe, replaced, repaired or removed from service? **(See records check list)**				
§192.703(c)	Are hazardous leaks repaired promptly?				

XXX. PART 192 – PATROLLING TRANSMISSION			S	N/I	U	N/A
§192.605(b)	Procedures for §192.705?					
§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
§192.605(b)	Procedures for §192.706?				
§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
§192.605(b)	Procedures for §192.707?				
§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(b)	EXCEPTIONS where line markers are NOT required:				
	(1) lines located at crossings of or under waterways and other water bodies				
	(2) mains in Class 3 or 4 location where damage prevention program is in effect under §192.614				
	(3) transmission lines in Class 3 or 4 locations until 3/20/1996				
	(4) transmission lines in Class 3 or 4 locations where placement of line marker is impractical				
§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

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).*				
§192.711(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.				
§192.717	Were any weld repairs made on transmission lines?				

XXXIII. PART 192 – FIELD REPAIRS: TRANSMISSION LINES		S	N/I	U	N/A
	Did it meet the following? 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)	Were any segments of pipe replaced within the system? (yes or no) If yes, was the 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)*				
§192.719(b)	Were any repairs made by welding? If yes, was the weld made in accordance with §§192.713, 192.715, and 192.717 and examined in accordance with §192.241.				

XXXIV. PART 192 – PATROLLING DISTRIBUTION		S	N/I	U	N/A
§192.605(b)	Procedures for §192.721? **(See records check list)**				
§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
§192.739(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:				

XXXVIII. PART 192 – PRESSURE LIMITING AND REGULATING STATIONS		S	N/I	U	N/A
	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)				
§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
§192.605(b)	Procedures for §192.745?				
§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
§192.605(b)	Procedures for §192.745?				
§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
§192.605(b)	Procedures for §192.749?				

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.				
§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?				
§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 – CAULKED BELL & SPIGOT JOINTS: CAST IRON		S	N/I	U	N/A
§192.605(b)	Procedures for §192.753?				
§192.753	Does the operator have cast-iron pipe with caulked bell and spigot joints that is subject to **25 psig** or more?				
§192.753(a)	Does the operator install mechanical clamps, or use a material or devices that will not reduce the flexibility of the joint, permanently bonds, and seals in a manner that meets the strength, environmental, and chemical compatibility requirements of §192.53(a) and (b) and §192.143?				
§192.753(b)	When each cast-iron caulked bell and spigot joint subject to pressures of 25 psig or less is exposed, does the operator seal by a means other than caulking?				
§192.275(a) & §192.275(b)	Is the cast iron pipe sealed with mechanical leak clamps with a gasket as a sealing medium confined and retained under compression by a separate gland or follower ring?				

XLV. PART 192 – PROTECTING CAST IRON PIPELINES		S	N/I	U	N/A
§192.605(b)	Procedures for §192.755?				
§192.755	When the operator has knowledge that a segment of buried cast-iron pipe is disturbed, does the operator provide protection from:				
§192.755(a)(1)	Vibrations from heavy construction equipment, trains, trucks, buses, or blasting.				
§192.755(a)(2)	Impact forces by vehicles				
§192.755(a)(3)	Earth movement				
§192.755(a)(4)	Apparent future excavations near the pipeline				

XLV. PART 192 – PROTECTING CAST IRON PIPELINES		S	N/I	U	N/A
§192.755(a)(5)	Other foreseeable outside forces which might subject that segment of pipeline to a bending stress?				
§192.755(b)	As soon as feasible does the operator provide permanent protection for the disturbed section?				