COMPARISON OF REGULATORY OVERSIGHT FOR STORAGE TANKS AND ANCILLARY EQUIPMENT

Introduction

The enclosed table represents a comparison between EPA and DOT regulations for tanks and associated equipment. It compares and contrasts the different regulatory requirements between EPA and DOT for various categories, such as operations, design, containment, emergency response, security and training. Each agency has prescriptive requirements for the above categories and in many cases, places emphasis on similar issues.

DOT Pipeline Regulatory Background

DOT's pipeline regulations cover pipeline facilities and the transportation of hazardous liquids or carbon dioxide associated with those facilities in or affecting interstate or foreign commerce. (See 49 CFR 195.1). Note that a pipeline system means ***all parts of a pipeline facility through which a hazardous liquid or carbon dioxide moves in transportation***, including, but not limited to, line pipe, valves, ***and other appurtenances connected to line pipe***, pumping units, fabricated assemblies associated with pumping units, metering and delivery stations and fabricated assemblies therein, and breakout tanks**. (Emphasis added-See 49 CFR 195.2).** Hazardous liquid means petroleum, petroleum products, or anhydrous ammonia. (49 CFR 195.2). Petroleum product means flammable, toxic, or corrosive products obtained from distilling and processing of crude oil, unfinished oils, natural gas liquids, blend stocks and other miscellaneous hydrocarbon compounds. Pipeline facility means new and existing pipe, rights-of-way ***and any equipment***, facility, or building ***used in the transportation of hazardous liquids*** or carbon dioxide. **(Emphasis added-See 49 CFR 195.2).** As can be seen from the aforementioned definitions, DOT's regulations are broad in terms of the petroleum products, equipment and appurtenances they cover. Therefore, the existing statutory and regulatory framework should provide DOT with the requisite enforcement authority over all pipeline systems and associated equipment involved in interstate transportation.

It cannot be emphasized enough that the underlying statutory scheme for DOT's pipeline safety regulations, as well as DOT's stated policies, promote both pipeline safety and protection of the environment. Examples of statutory mandates and policy statements protective of the environmental include, but are not limited to:

- PHMSA's Mission Statement- "To protect people and the environment from the risks inherent in transportation of hazardous materials - by pipeline and other modes of transportation."

- Accountable Pipeline and Safety Partnership Act of 1996 "An Act to reduce risk to public safety ***and the environment*** associated with pipeline transportation of natural gas and hazardous liquids, and for other purposes."

- http://primis.phmsa.dot.gov/iim/index.htm -PHMSA's integrity management web page, which includes the following statement: "These rules, effective May 29, 2001, and February 15, 2002, specify regulations to assess, evaluate, repair and validate through comprehensive analysis the integrity of hazardous liquid pipeline segments that, in the event of a leak or failure, could affect populated areas, areas unusually sensitive to environmental damage and **commercially navigable waterways.**"

- Oil Pollution Act of 1990 (OPA '90)- PHMSA has responsibility for implementing the Oil Pollution Act of 1990 as it applies to onshore oil pipelines. PHMSA's stated goal is to decrease the likelihood of pipeline spills, ***diminish the environmental consequences of spills***, and ensure that the responses to spills are swift and well planned. PHMSA states that its program has several elements, all of which are intended to ensure that pipeline operators are able to ***protect the environment*** from major oil spills. See http://ops.dot.gov/init/opa/opa.htm for a full description of PHMSA's goals under OPA '90.

When an Enforcement Case is opened, PHMSA uses its full range of enforcement mechanisms to require that an operator takes appropriate and timely corrective actions to address the alleged non-compliances and deficiencies that are identified. PHMSA "closes" these enforcement items once it is satisfied that all identified corrective actions have been taken, all inadequate procedures corrected, and all civil penalties paid. In 2007, PHMSA initiated 259 enforcement cases against pipeline operators. The enclosed link provides specific facilities and companies that were subject to enforcement actions from 2002 through 2008, year to date. As can be seen from the included link, PHMSA's enforcement presence is significant.
http://primis.phmsa.dot.gov/comm/reports/enforce/CasesOpen_opid_0.html#_TP_1_tab_2

COMPARISON TABLE

General Statutory/Regulatory Information

Item	EPA	DOT
Statutes	Federal Water Pollution Control Act	49 USC 60101 et. seq. (pipeline safety laws) 49 USC 5101 et. seq. (hazardous materials transportation laws)
CFR	40 CFR 112 Oil Pollution Prevention 40 CFR 110 Discharge of Oil	49 CFR 194 Response Plans for Onshore Pipelines 49 CFR 195 Transportation of Hazardous Liquid by Pipeline 49 CFR 199 Drug and Alcohol Testing
Universe of Tanks & Equipment	• Diverse population of tanks at a broad variety of facilities including power generating and farming • Includes broad categories of products including petroleum, vegetable oils, wastes, etc.	• Breakout tanks associated with pipeline systems and pipeline appurtenances • Pipeline Facilities-New and existing pipe, rights-of-way ***and any equipment***, facility, or building ***used in the transportation of hazardous liquids*** or carbon dioxide • Hazardous liquids (e.g. petroleum, petroleum products, anhydrous ammonia) • Petroleum products- Flammable, toxic, or corrosive products obtained from distilling and processing of crude oil, unfinished oils, natural gas liquids, blend stocks and other miscellaneous hydrocarbon compounds.
Accident and release reporting	• Reporting required for "sheen quantities" on water; 40 CFR 110.6	• Accident reporting required based on thresholds (5 gallons release; injury, death; pollution of surface water (violation of water quality standards); clean up and loss of product exceeding $50,000; fire; etc.) • Reporting of sheen on water; 40 CFR 110 also applies to DOT facilities

DESIGN/CONSTRUCTION/INITIAL TESTING

Item	EPA	DOT
General Design/Construction	• Materials and construction compatible with material stored and conditions; 112.8(c)	49 CFR 195.132-Design and construction of new aboveground breakout tanks. (a) Each aboveground breakout tank must be designed and constructed to withstand the internal pressure produced by the hazardous liquid to be stored therein and any anticipated external loads. (b) For aboveground breakout tanks first placed in service after October 2, 2000, compliance with paragraph (a) of this section requires one of the following: (1) Shop-fabricated, vertical, cylindrical, closed top, welded steel tanks with nominal capacities of 90 to 750 barrels (14.3 to 119.2 m \3\) and with internal vapor space pressures that are approximately atmospheric must be designed and constructed in accordance with API Specification 12F. (2) Welded, low-pressure (i.e., internal vapor space pressure not greater than 15 psig (103.4 kPa)), carbon steel tanks that have wall shapes that can be generated by a single vertical axis of revolution must be designed and constructed in accordance with API Standard 620. (3) Vertical, cylindrical, welded steel tanks with internal pressures at the tank top approximating atmospheric pressures (i.e., internal vapor space pressures not greater than 2.5 psig (17.2 kPa), or not greater than the pressure developed by the weight of the tank roof) must be designed and constructed in accordance with API Standard 650. (4) High pressure steel tanks (i.e., internal gas or vapor space pressures greater than 15 psig (103.4 kPa)) with a nominal capacity of 2000 gallons (7571 liters) or more of liquefied petroleum 195.132

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		49 CFR 195.205-Aboveground tanks already in service (a) Aboveground breakout tanks that have been repaired, altered, or reconstructed and returned to service must be capable of withstanding the internal pressure produced by the hazardous liquid to be stored therein and any anticipated external loads. (b) After October 2, 2000, compliance with paragraph (a) of this section requires the following for the tanks specified: (1) For tanks designed for approximately atmospheric pressure constructed of carbon and low alloy steel, welded or riveted, and non-refrigerated and tanks built to API Standard 650 or its predecessor Standard 12C, repair, alteration, and reconstruction must be in accordance with API Standard 653. (2) For tanks built to API Specification 12F or API Standard 620, the repair, alteration, and reconstruction must be in accordance with the design, welding, examination, and material requirements of those respective standards. (3) For high pressure tanks built to API Standard 2510, repairs, alterations, and reconstruction must be in accordance with API 510 49 CFR 195.405-Protection against ignitions and safe access/egress involving floating roofs (a) After October 2, 2000, protection provided against ignitions arising out of static electricity, lightning, and stray currents during operation and maintenance activities involving aboveground breakout tanks must be in accordance with API Recommended Practice 2003, unless the operator notes in the procedural manual (Sec. 195.402(c)) why compliance with all or certain provisions of API Recommended Practice 2003 is not necessary for the safety of a particular breakout tank.

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		(b) The hazards associated with access/egress onto floating roofs of in-service aboveground breakout tanks to perform inspection, service, maintenance or repair activities (other than specified general considerations, specified routine tasks or entering tanks removed from service for cleaning) are addressed in API Publication 2026. After October 2, 2000, the operator must review and consider the potentially hazardous conditions, safety practices and procedures in API Publication 2026 for inclusion in the procedure manual (Sec. 195.402(c)).
Overfill protection	• Engineer or update each container installation in accordance with good engineering practice to avoid discharges. You must provide at least one of the following devices: (i) High liquid level alarms with an audible or visual signal at a constantly attended operation or surveillance station. In smaller facilities an audible air vent may suffice. (ii) High liquid level pump cutoff devices set to stop flow at a predetermined container content level. (iii) Direct audible or code signal communication between the container gauger and the pumping station. (iv) A fast response system for determining the liquid level of each bulk storage container such as digital computers, telepulse, or direct vision gauges. If you use this alternative, a person must be present to monitor gauges and the overall filling of bulk storage containers. (v) You must regularly test liquid level sensing devices to ensure proper operation. 112.8(c)(8)	49 CFR 195.428 Overpressure safety devices and overfill protection systems. (a) Except as provided in paragraph (b) of this section, each operator shall, at intervals not exceeding 15 months, but at least once each calendar year, or in the case of pipelines used to carry highly volatile liquids, at intervals not to exceed 7\1/2\ months, but at least twice each calendar year, inspect and test each pressure limiting device, relief valve, pressure regulator, or other item of pressure control equipment to determine that it is functioning properly, is in good mechanical condition, and is adequate from the standpoint of capacity and reliability of operation for the service in which it is used. (b) In the case of relief valves on pressure breakout tanks containing highly volatile liquids, each operator shall test each valve at intervals not exceeding 5 years. (c) Aboveground breakout tanks that are constructed or significantly altered according to API Standard 2510 after October 2, 2000, must have an overfill protection system installed according to section 5.1.2 of API Standard 2510. Other aboveground breakout tanks with 600 gallons (2271 liters) or more of storage capacity that are constructed or significantly altered after October 2, 2000, must have an overfill protection system installed according to API Recommended Practice 2350. However, operators need not comply with any part of API

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		Recommended Practice 2350 for a particular breakout tank if the operator notes in the manual required by Sec. 195.402 why compliance with that part is not necessary for safety of the tank. (d) After October 2, 2000, the requirements of paragraphs (a) and (b) of this section for inspection and testing of pressure control equipment apply to the inspection and testing of overfill protection systems.
Secondary containment	• General containment (areas with potential for discharge, e.g., piping, oil-filled operating and manufacturing equipment, and non-rack related transfer areas). The entire containment system, including walls and floor, must be capable of containing oil and must be constructed so that any discharge from a primary containment system, such as a tank or pipe, will not escape the containment system before cleanup occurs. 112.7(c) • Loading/unloading racks-1) Where loading/unloading area drainage does not flow into a catchment basin or treatment facility designed to handle discharges, use a quick drainage system for tank car or tank truck loading and unloading areas. You must design any containment system to hold at least the maximum capacity of any single compartment of a tank car or tank truck loaded or unloaded at the facility. 112.7(h)(1) • Position or locate mobile or portable oil storage containers to prevent a discharge as described in Sec. 112.1(b). Except for mobile refuelers, you must furnish a secondary means of containment, such as a dike or catchment basin, sufficient to contain the capacity of the largest single compartment or container with sufficient freeboard to contain precipitation. 112.8(c)(11) • Construct all bulk storage tank installations (except mobile refuelers) so that you provide a secondary means of containment for the entire capacity of the largest single container and sufficient freeboard to contain precipitation. You must ensure that diked areas are sufficiently	49 CFR 195.264-Impoundment, protection against entry, normal/emergency venting or pressure/vacuum relief for aboveground breakout tanks: (a) A means must be provided for containing hazardous liquids in the event of spillage or failure of an aboveground breakout tank. (b) After October 2, 2000, compliance with paragraph (a) of this section requires the following for the aboveground breakout tanks specified: (1) For tanks built to API Specification 12F, API Standard 620, and others (such as API Standard 650 or its predecessor Standard 12C), the installation of impoundment must be in accordance with the following sections of NFPA 30: (i) Impoundment around a breakout tank must be installed in accordance with section 4.3.2.3.2 [of NFPA 30]; and (ii) Impoundment by drainage to a remote impounding area must be installed in accordance with section 4.3.2.3.1 [of NFPA 30]. (2) For tanks built to API 2510, the installation of impoundment must be in accordance with section 5 or 11 of API 2510 (incorporated by reference, *see* §195.3).

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	impervious to contain discharged oil. Dikes, containment curbs, and pits are commonly employed for this purpose. You may also use an alternative system consisting of a drainage trench enclosure that must be arranged so that any discharge will terminate and be safely confined in a facility catchment basin or holding pond. 112.8(c)(2) • Facility drainage. (1) Restrain drainage from diked storage areas by valves to prevent a discharge into the drainage system or facility effluent treatment system, except where facility systems are designed to control such discharge. You may empty diked areas by pumps or ejectors; however, you must manually activate these pumps or ejectors and must inspect the condition of the accumulation before starting, to ensure no oil will be discharged. (2) Use valves of manual, open-and-closed design, for the drainage of diked areas. You may not use flapper-type drain valves to drain diked areas. If your facility drainage drains directly into a watercourse and not into an on-site wastewater treatment plant, you must inspect and may drain uncontaminated retained stormwater, as provided in paragraphs (c)(3)(ii), (iii), and (iv) of this section. (3) Design facility drainage systems from undiked areas with a potential for a discharge (such as where piping is located outside containment walls or where tank truck discharges may occur outside the loading area) to flow into ponds, lagoons, or catchment basins designed to retain oil or return it to the facility. You must not locate catchment basins in areas subject to periodic flooding. (4) If facility drainage is not engineered as in paragraph (b)(3) of this section, equip the final discharge of all ditches inside the facility with a diversion system that	

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	would, in the event of an uncontrolled discharge, retain oil in the facility. (5) Where drainage waters are treated in more than one treatment unit and such treatment is continuous, and pump transfer is needed, provide two ``lift" pumps and permanently install at least one of the pumps. Whatever techniques you use, you must engineer facility drainage systems to prevent a discharge as described in Sec. 112.1(b) in case there is an equipment failure or human error at the facility. 112.8(b).	
Cathodic protection	• Protect any completely buried metallic storage tank installed on or after January 10, 1974 from corrosion by coatings or cathodic protection compatible with local soil conditions. You must regularly leak test such completely buried metallic storage tanks. Do not use partially buried or bunkered metallic tanks for the storage of oil, unless you protect the buried section of the tank from corrosion. You must protect partially buried and bunkered tanks from corrosion by coatings or cathodic protection compatible with local soil conditions. 112.7(c)(4)(5) • Facility transfer operations, pumping, and facility process.- Provide buried piping that is installed or replaced on or after August 16, 2002, with a protective wrapping and coating. You must also cathodically protect such buried piping installations or otherwise satisfy the corrosion protection standards for piping in part 280 of this chapter or a State program approved under part 281 of this chapter. If a section of buried line is exposed for any reason, you must carefully inspect it for deterioration. If you find corrosion damage, you must undertake additional examination and corrective action as indicated by the magnitude of the damage. 112.7(d)	• After October 2, 2000, when you install cathodic protection under Sec. 195.563(a) to protect the bottom of an aboveground breakout tank of more than 500 barrels (79.5m\3\) capacity built to API Specification 12F, API Standard 620, or API Standard 650 (or its predecessor Standard 12C), you must install the system in accordance with API Recommended Practice 651. 49 CFR 195.557 Which pipelines must have coating for external corrosion control? Except bottoms of aboveground breakout tanks, each buried or submerged pipeline must have an external coating for external corrosion control if the pipeline is-- (a) Constructed, relocated, replaced, or otherwise changed after the applicable date in Sec. 195.401(c), not including the movement of pipe covered by Sec. 195.424; or (b) Converted under Sec. 195.5 and-- (1) Has an external coating that substantially meets Sec. 195.559 before the pipeline is placed in service; or (2) Is a segment that is relocated, replaced, or substantially altered.

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		49 CFR 195.563 Which pipelines must have cathodic protection? (a) Each buried or submerged pipeline that is constructed, relocated, replaced, or otherwise changed after the applicable date in Sec. 195.401(c) must have cathodic protection. The cathodic protection must be in operation not later than 1 year after the pipeline is constructed, relocated, replaced, or otherwise changed, as applicable. (b) Each buried or submerged pipeline converted under Sec. 195.5 must have cathodic protection if the pipeline-- (1) Has cathodic protection that substantially meets Sec. 195.571 before the pipeline is placed in service; or (2) Is a segment that is relocated, replaced, or substantially altered. (c) All other buried or submerged pipelines that have an effective external coating must have cathodic protection.\1\ Except as provided by paragraph (d) of this section, this requirement does not apply to breakout tanks and does not apply to buried piping in breakout tank areas and pumping stations until December 29, 2003. \1\ A pipeline does not have an effective external coating material if the current required to cathodically protect the pipeline is substantially the same as if the pipeline were bare. (d) Bare pipelines, breakout tank areas, and buried pumping station piping must have cathodic protection in places where regulations in effect before January 28, 2002 required cathodic protection as a result of electrical inspections. See previous editions of this part in 49 CFR, parts 186 to 199. (e) Unprotected pipe must have cathodic protection if required by Sec. 195.573(b). 49 CFR 195.579 What must I do to mitigate internal corrosion? (a) General. If you transport any hazardous liquid or carbon dioxide that would corrode the pipeline, you must investigate the corrosive effect of the hazardous liquid or carbon dioxide on the pipeline and take adequate steps to mitigate internal corrosion. (b) Inhibitors. If you use corrosion inhibitors to mitigate

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		internal corrosion, you must-- (1) Use inhibitors in sufficient quantity to protect the entire part of the pipeline system that the inhibitors are designed to protect; (2) Use coupons or other monitoring equipment to determine the effectiveness of the inhibitors in mitigating internal corrosion; and (3) Examine the coupons or other monitoring equipment at least twice each calendar year, but with intervals not exceeding 7\1/2\ months. (c) Removing pipe. Whenever you remove pipe from a pipeline, you must inspect the internal surface of the pipe for evidence of corrosion. If you find internal corrosion requiring corrective action under Sec. 195.585, you must investigate circumferentially and longitudinally beyond the removed pipe (by visual examination, indirect method, or both) to determine whether additional corrosion requiring remedial action exists in the vicinity of the removed pipe. (d) Breakout tanks. After October 2, 2000, when you install a tank bottom lining in an aboveground breakout tank built to API Specification 12F, API Standard 620, or API Standard 650 (or its predecessor Standard 12C), you must install the lining in accordance with API Recommended Practice 652. However, installation of the lining need not comply with API Recommended Practice 652 on any tank for which you note in the corrosion control procedures established under Sec. 195.402(c)(3) why compliance with all or certain provisions of API Recommended Practice 652 is not necessary for the safety of the tank.
Security	• Security (excluding oil production facilities). (1) Fully fence each facility handling, processing, or storing oil, and lock and/or guard entrance gates when the facility is not in production or is unattended. (2) Ensure that the master flow and drain valves and any other valves permitting direct outward flow of the container's contents to the surface have adequate security measures so that they remain in the closed	• Each operator shall provide protection for each pumping station and breakout tank area and other exposed facility (such as scraper traps) from vandalism and unauthorized entry. 195.436(b) • Aboveground breakout tank areas must be adequately protected against unauthorized entry. 195.264(c): • The security plans for facilities identified as "critical" under the Transportation Security Administration (TSA)

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	position when in non-operating or non-standby status. (3) Lock the starter control on each oil pump in the ``off'' position and locate it at a site accessible only to authorized personnel when the pump is in a non-operating or non-standby status. (4) Securely cap or blank-flange the loading/unloading connections of oil pipelines or facility piping when not in service or when in standby service for an extended time. This security practice also applies to piping that is emptied of liquid content either by draining or by inert gas pressure. (5) Provide facility lighting commensurate with the type and location of the facility that will assist in the: (i) Discovery of discharges occurring during hours of darkness, both by operating personnel, if present, and by non-operating personnel (the general public, local police, etc.); and (ii) Prevention of discharges occurring through acts of vandalism. 112.8(d)	critical facility designation criteria are reviewed by the TSA. The TSA is in the process of scheduling visits to critical facilities to inspect security measures at these facilities.
Testing	• For bulk storage containers, conduct both periodic integrity testing of the containers and periodic integrity and leak testing of the valves and piping; 112.7(d) Test each aboveground container for integrity on a regular schedule, and whenever you make material repairs. The frequency of and type of testing must take into account container size and design (such as floating roof, skid-mounted, elevated, or partially buried). You must combine visual inspection with another testing technique such as hydrostatic testing, radiographic testing, ultrasonic testing, acoustic emissions testing, or another system of non-destructive shell testing. You must keep comparison records and you must also inspect the container's supports and foundations. In addition, you must frequently inspect the outside of the container for signs of deterioration, discharges, or accumulation of oil inside diked areas. Records of	195.307 Pressure testing aboveground breakout tanks. (a) For aboveground breakout tanks built to API Specification 12F and first placed in service after October 2, 2000, pneumatic testing must be in accordance with section 5.3 of API Specification 12F. (b) For aboveground breakout tanks built to API Standard 620 and first placed in service after October 2, 2000, hydrostatic and pneumatic testing must be in accordance with section 7.18 of API Standard 620 (incorporated by reference, see Sec. 195.3). (c) For aboveground breakout tanks built to API Standard 650 and first placed in service after October 2, 2000, hydrostatic and pneumatic testing must be in accordance with section 5.3 of API Standard 650. (d) For aboveground atmospheric pressure breakout tanks constructed of carbon and low alloy steel, welded or riveted, and

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	inspections and tests kept under usual and customary business practices will suffice for purposes of this paragraph.112.8(c)(6) • If a field-constructed aboveground container undergoes a repair, alteration, reconstruction, or a change in service that might affect the risk of a discharge or failure due to brittle fracture or other catastrophe, or has discharged oil or failed due to brittle fracture failure or other catastrophe, evaluate the container for risk of discharge or failure due to brittle fracture or other catastrophe, and as necessary, take appropriate action. 112.7(i)	non-refrigerated and tanks built to API Standard 650 or its predecessor Standard 12C that are returned to service after October 2, 2000, the necessity for the hydrostatic testing of repair, alteration, and reconstruction is covered in section 10.3 of API Standard 653. (e) For aboveground breakout tanks built to API Standard 2510 and first placed in service after October 2, 2000, pressure testing must be in accordance with ASME Boiler and Pressure Vessel Code, Section VIII, Division 1 or 2. Sec. 195.302 General requirements: (a) Except as otherwise provided in this section and in Sec. 195.305(b), no operator may operate a pipeline unless it has been pressure tested under this subpart without leakage. In addition, no operator may return to service a segment of pipeline that has been replaced, relocated, or otherwise changed until it has been pressure tested under this subpart without leakage. (b) Except for pipelines converted under Sec. 195.5, the following pipelines may be operated without pressure testing under this subpart: (1) Any hazardous liquid pipeline whose maximum operating pressure is established under Sec. 195.406(a)(5) that is-- (i) An interstate pipeline constructed before January 8, 1971; (ii) An interstate offshore gathering line constructed before August 1, 1977; (iii) An intrastate pipeline constructed before October 21, 1985; or (iv) A low-stress pipeline constructed before August 11, 1994 that transports HVL. (2) Any carbon dioxide pipeline constructed before July 12, 1991, that-- (i) Has its maximum operating pressure established under Sec. 195.406(a)(5); or (ii) Is located in a rural area as part of a production field distribution system. (3) Any low-stress pipeline constructed before August 11, 1994 that does not transport HVL. (4) Those portions of older hazardous liquid and carbon dioxide pipelines for which an operator has elected the risk-based

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		alternative under Sec. 195.303 and which are not required to be tested based on the risk-based criteria. (c) Except for pipelines that transport HVL onshore, low-stress pipelines, and pipelines covered under Sec. 195.303, the following compliance deadlines apply to pipelines under paragraphs (b)(1) and (b)(2)(i) of this section that have not been pressure tested under this subpart: (1) Before December 7, 1998, for each pipeline each operator shall-- (i) Plan and schedule testing according to this paragraph; or (ii) Establish the pipeline's maximum operating pressure under Sec. 195.406(a)(5). (2) For pipelines scheduled for testing, each operator shall-- (i) Before December 7, 2000, pressure test-- (A) Each pipeline identified by name, symbol, or otherwise that existing records show contains more than 50 percent by mileage (length) of electric resistance welded pipe manufactured before 1970; and (B) At least 50 percent of the mileage (length) of all other pipelines; and (ii) Before December 7, 2003, pressure test the remainder of the pipeline mileage (length). Sec. 195.305 Testing of components. (a) Each pressure test under Sec. 195.302 must test all pipe and attached fittings, including components, unless otherwise permitted by paragraph (b) of this section. (b) A component, other than pipe, that is the only item being replaced or added to the pipeline system need not be hydrostatically tested under paragraph (a) of this section if the manufacturer certifies that either-- (1) The component was hydrostatically tested at the factory; or (2) The component was manufactured under a quality control system that ensures each component is at least equal in strength to a prototype that was hydrostatically tested at the factory.

Operations, Maintenance, and Inspection

Item	EPA	DOT
Facility documentation	• Covered by 112.7(a)(3)(i), (ii) & (iii) -Layout of facility and drainage;	• Location and identification of breakout tanks; pump station, valves, et. (maps & plans) 195.404
Tank piping	• Covered by 112.8(d)(4) Integrity Testing for Aboveground Valves, Piping & Appurtenances as well as buried piping.	• Covered by 49 CFR 195.112, 195.114 & 195.305 (i.e., new and used pipe specifications)
Regular inspections	• Covered by 112.7 (e) "Inspections, tests and records; Written procedures required in SPCC plan with suggestions for items to be inspected also covered under 112.3(d) where the PE is certifying that inspections and testing have been established	• Inspections as required by API 653, or • Annual breakout tank inspection; 195.432 (a) Except for breakout tanks inspected under paragraphs (b) and (c) of this section, each operator shall, at intervals not exceeding 15 months, but at least once each calendar year, inspect each in-service breakout tank. (b) Each operator shall inspect the physical integrity of in-service atmospheric and low-pressure steel aboveground breakout tanks according to section 4 of API Standard 653. However, if structural conditions prevent access to the tank bottom, the bottom integrity may be assessed according to a plan included in the operations and maintenance manual under Sec. 195.402(c)(3). (c) Each operator shall inspect the physical integrity of in-service steel aboveground breakout tanks built to API Standard 2510 according to section 6 of API 510. (d) The intervals of inspection specified by documents referenced in paragraphs (b) and (c) of this section begin on May 3, 1999, or on the operator's last recorded date of the inspection, whichever is earlier. *(Note: API 653 inspections include monthly in-service visual inspections for leakage, periodic in-service inspection for exterior condition, periodic exterior tank shell ultrasonic thickness inspections and interior inspections for corrosion and tank bottom condition and minimum thickness assessments.)*

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Written procedures	• Covered under 112.7(e) Records of written procedures for container testing and inspection must be kept with the plan; SPCC plans must have written procedures for inspections.	• Operating, Maintenance, and Emergency manuals required; 195.402
Imminent threats	• Covered under 112.7(g) Security	• Safety related condition reports; 195.55; 195.56

Emergency Response

Item	EPA	DOT
Planning for spill response	• OPA plans under 40 CFR 112.20 • Response Plans -facilities with >1,320 gallons	• OPA plans under 49 CFR 194 • Emergency plans under 49 CFR 195 • Response Plans – any DOT regulated pipeline.
Response Times	• 1-hour response and 1,000 feet of containment boom – 40 CFR 112, Appendix E, Section 3.3.1	• Within stipulated responses times for a geographic area; 49 CFR 194.5
Diagrams	• Detailed facility specific Site, Drainage, and Evacuation diagrams; 40 CFR 112, Appendix F, Section 1.9 Diagrams	• Response Zone Maps and Evacuation Diagrams. No drainage map requirements other than overland spread calculations for the pipeline which may include the tank farm.
Plan Approval	• One time submittal with regular updates	• Resubmit every 5 years for DOT approval; 194.121
High Consequence Area	• Appendix F, Part 112, Section 1.4.2 Vulnerability Analysis	• Appendix C – Guidance for Implementation of an Integrity Management Program, Section A
Planning Distance	• Attachment C-III – Calculation of the Planning Distance	• Appendix C – Guidance for Implementation of an Integrity Management Program, Section B
Drills	• PREP 112.21	• PREP 112.21

PEOPLE REQUIREMENTS

Item	EPA	DOT
Drug and alcohol testing	• No requirements	• Pre-employment, post accident, random testing, REASONABLE CAUSE, RETURN TO DUTY AND FOLLOW-UP TESTING
Operator Qualification	• No requirements	• 49 CFR Part 192 Subpart N and Part 195 Subpart G • Individuals are required to be qualified whenever performing covered tasks (BOTH OPERATIONS AND MAINTENANCE) on DOT regulated facilities • Individuals found to be involved in the cause of a DOT reportable release must be disqualified from performing those tasks which are involved and requalified prior to performing those tasks.
Training	• Periodic spill briefings; 112.7(3)(10) • Training and drills; 112.21	• Training requirements: 194.117 (a) and (b) • Training requirements; 195.403(a) and (b) • Operator qualification rule; 195.501-509
Public Awareness	• No requirement	• A written Public Awareness Program; 195.440