Chapter 600: OIL DISCHARGE PREVENTION AND POLLUTION CONTROL RULES FOR MARINE OIL TERMINALS, TRANSPORTATION PIPELINES AND VESSELS

SUMMARY: This chapter sets forth minimum design and operating requirements for marine oil terminals and intrastate pipelines. Separate sections are included for vessel operation and navigation, siting requirements, design and construction standards for new and existing marine oil terminal facilities, staff training and safety, and closure of tanks and facilities.

1. Preamble. It is the purpose of this chapter, consistent with legislative policy, to provide necessary oil spill prevention and control rules for all facilities and operations associated with marine oil terminals, intrastate pipelines and vessels, so as to prevent discharges of oil to the waters of the State.

2. Definitions. The following terms as used in this chapter have the following meanings:

A. Aboveground oil storage tank. "Aboveground oil storage tank", also referred to as a "tank", means any stationary container, of which more than 90% is above the surface of the ground and is used or intended to be used for the storage or supply of oil. Included in this definition are any tanks situated upon or above the surface of a floor and in such a manner that they may be readily inspected. For the purpose of this chapter, aboveground oil storage tanks do not include aboveground propane storage tanks.

B. Alter. "Alter" means any enlargement, upgrading, repair or removal of a storage tank system or any change in the configuration of the piping, tanks, diking or the replacement of any tank. The term "alteration" has the same meaning.

C. Approved. "Approved" means approved by the Commissioner or the commissioner's designee in writing or orally with written confirmation as soon as practicable.

D. Bulk. "Bulk" means material in any quantity that is shipped, stored, or handled without benefit of package, label, mark or count and carried in integral or fixed independent tanks.

E. Bulk oil or oil carried in bulk or as cargo. "Bulk oil" or "oil carried in bulk" or as "cargo" means any oil not carried as fuel for bunkering or recovered incident to oil spill response activities.

F. Cathodically protected. "Cathodically protected" means the use of a technique, consistent with the National Association of Corrosion Engineers publication, "Recommended Practices for Installation of Underground Liquid Storage Systems, RP-100-97, 1997 as amended, to prevent the corrosion of a metal surface by making that surface the cathode of an electrochemical cell.

G. Cathodic protection assessment. "Cathodic protection assessment" means an analysis to determine the need for cathodic protection in order to protect a tank bottom from corrosion. This assessment will be based upon a corrosion survey that includes soil analysis and resistivity measurements, operating records, corrosion history, corrosion allowance, prior test results with similar tank systems in similar environments and current and future plans for the tank.

H. Cathodic protection tester. "Cathodic protection tester" means, at a minimum, a person certified as a Senior Corrosion Technologist, Corrosion Technologist, or Corrosion Technician by the National Association of Corrosion Engineers.

I. Combustible liquid. "Combustible liquid" means a liquid which has a flash point at or above 100° F (37.8° C). Combustible liquids are subdivided as follows:

(1) Class II liquids include those having flash points at or above 100° F (37.8° C) and below 140° F (60° C).

(2) Class III A liquids include those having flash points at or above 140° F (60° C) and below 200° F (93° C).

(3) Class IIIB liquids include those having flash points at or above 200° F (93° C).

J. Commissioner. "Commissioner" means the Commissioner of Environmental Protection.

K. Department. "Department" means the Department of Environmental Protection composed of the Board of Environmental Protection and the Commissioner.

L. Discharge. "Discharge" means any spilling, leaking, pumping, pouring, emitting, emptying, or dumping either directly or indirectly to the waters of the State of Maine.

M. Emergent vegetation. "Emergent vegetation" means erect, rooted and herbaceous plants growing in saturated or permanently flooded areas that do not tolerate prolonged inundation of the entire plant.

N. Existing aboveground oil storage tank. "Existing aboveground oil storage tank" means an aboveground oil storage tank that was constructed before the effective date of this chapter.

O. Existing oil terminal facility. "Existing oil terminal facility" means a facility that held a valid oil terminal facility license on the effective date of this chapter

P. Existing oil and chemical handling areas. "Existing oil and chemical handling areas" are the areas inside the existing footprint of the facility. The existing footprint includes the developed areas of the facility such as the dike, tank, piping, and loading rack areas.

Q. Facility. "Facility" or "Oil Terminal Facility" means any facility of any kind and related appurtenances, located in, on or under the surface of any land or water, including submerged lands, which is used or capable of being used for the purpose of transferring, processing or refining oil, or for the purpose of storing the same, but does not include any facility used or capable of being used to store no more than 1,500 barrels (63,000 gallons), nor any facility not engaged in the transfer of oil to or from waters of the State. A vessel is considered an oil terminal facility only in the event of a vessel-to-vessel transfer of oil, but only that vessel going to or coming from the place of vessel-to-vessel transfer and a permanent or fixed oil terminal facility. The term does not include vessels engaged in oil spill response activities.

R. Facility closure. "Facility closure" means closure of a facility in a manner prescribed by subsection 12(D) of this chapter.

S. Flammable liquid. A "flammable liquid" is a liquid having a flash point below 100° F (37.8° C) and having a vapor pressure not exceeding 40 lbs. per sq. inch (absolute) (2,068 mm Hg) at 100° F (37.8° C). Flammable (Class I) liquids are subdivided as follows:

(1) Class IA liquids include those having flash points below 73° F (22.8° C) and having a boiling point below 100° F (37.8° C).

(2) Class IB liquids include those having flash points below 73° F (22.8° C) and having a boiling point at or above 100° F (37.8° C).

(3) Class IC liquids include those having flash points at or above 73° F (22.8° C) and below 100° F (37.8° C).

T. 100-year Flood plain. "100-year flood plain" means the 100-year flood plain as shown on Federal Emergency Management Agency (FEMA) Flood Insurance Rate Maps or Flood Hazard Boundary Maps, or the flood of record, or in the absence of these, by soil types identified as recent flood plain soils.

U. Handling. "Handling" means the storing, transferring, collecting, separating, salvaging, processing, reducing, recovering, incinerating, treating, disposing or transporting of oil.

V. Internal tank bottom liner. An "internal tank bottom liner" is an internal, bonded barrier on the tank bottom as described in American Petroleum Institute 652, Recommended Practice, Lining of Aboveground Storage Tank Bottoms, 2nd Ed. (December 1997).

W. Intrastate pipeline. "Intrastate pipeline" means a pipeline or that part of a pipeline that is used in the transportation of oil used in commerce within the State.

X. Monitoring well. "Monitoring well" means a dug or drilled, cased well or other device used to detect oil in ground water that can be used for detecting the presence of at least one-eighth of an inch of oil.

Y. New oil terminal facility. "New oil terminal facility" means an oil terminal facility whose application for a license is received after the effective date of this chapter.

Z. New aboveground oil storage tank. "New aboveground oil storage tank" means an aboveground oil storage tank permitted for construction after the effective date of this chapter.

AA. Oil. "Oil" means oil, petroleum products and their oil by-products of any kind and in any form including, but not limited to, petroleum, fuel, oil, sludge, oil refuse, oil mixed with other wastes, crude oils, oil additives, and all other liquid hydrocarbons regardless of specific gravity.

BB. Oil/water separator. "Oil/water separator" means a device used to separate and remove oil and oily wastes from oil and water mixtures.

CC. Owner or operator. "Owner or operator" means any person owning or operating an oil terminal facility or pipeline, whether by lease, contract or any other form of agreement or a person in control of, or having responsibility for, the daily operation of an oil storage facility.

DD. Owner. "Owner" means the person who alone or in conjunction with others owns an oil terminal facility.

EE. Person. "Person" means any natural person, firm, association, partnership, corporation, trust, the State of Maine and any agency thereof, governmental entity, quasi-governmental entity, the United States of America and any agency thereof and any other legal entity.

FF. Pipelines. "Pipelines" means all parts of an intrastate oil pipeline facility including 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.

GG. Piping. "Piping" means the piping and accessories within a facility used for the conveyance of oil between tanks or between tanks and loading and unloading points.

HH. Piping Run. A "piping run" means the piping between a bolted flange, valve, or pump.

II. Piping tightness test. "Piping tightness test" means a method to test the integrity of systems piping. The integrity of piping systems must be assured by one or more of the following: pressure testing, volumetric testing or internal instrument inspection devices designed to verify the structural integrity of the pipe by measuring pipe wall thickness and indicating geometric irregularities of the pipe line.

JJ. Private drinking water supply. "Private drinking water supply" means any dug, drilled or other type of well or spring or other source of water used for human or livestock consumption and that is not a public water supply.

KK. Public drinking water supply. "Public drinking water supply" has the same meaning as "public water system" in 22 M.R.S. Section 2601(8).

LL. Qualified person. "Qualified person" means an individual thoroughly familiar with the State spill prevention rules, and the specific maintenance procedures, inspection schedules, and oil spill response procedures in use at the facility where the individual is employed.

MM. Reconstructed tank. "Reconstructed tank" means any tank that has been dismantled, relocated to a new location and reassembled.

NN. Related appurtenances. "Related appurtenances" means all items pertaining to and making the oil terminal facility function. The term does not include day tanks that are not connected to pipelines, racks, or storage tanks which receive oil from marine transport. For example, tanks supplying start-up fuel for electrical generation and that are not connected to the marine oil terminal portions of the facility through pipelines or other means of oil transfer, and that are in no way related to the function of an oil terminal facility, are not considered "related appurtenances".

OO. Release prevention barriers (RPB). "Release prevention barriers" include steel bottoms, synthetic materials, clay liners and all other barriers or combination of barriers placed in the bottom of or under an aboveground storage tank that have these functions:

(1) preventing the escape of oil, and

(2) containing or channeling released material for leak detection.

This process is covered in detail in *American Petroleum Institute Standard 650, 10th Ed. (October 1998).*

PP. Secondary containment. "Secondary containment" means a system installed so that any material that is discharged or has discharged from the primary containment is prevented from reaching the soil or ground water outside the system for the anticipated period of time necessary to detect and recover the discharged material. Such a system may include, but is not limited to, impervious liners, double-walled tanks and piping, or any other method approved by the Commissioner that is technically feasible and effective, and meets the requirements of this chapter.

QQ. Significant ground water aquifer. "Significant ground water aquifer" means a porous formation of ice-contact and glacial outwash sand and gravel or fractured bedrock, as identified by the current Maine Geological Survey maps, that contains significant recoverable quantities of water which is likely to provide drinking water supplies.

NOTE: Sand and Gravel Aquifer Maps are available from the Maine Geological Survey, Department of Conservation, State House Station #22, Augusta, Maine 04333.

RR. Tank barge. "Tank barge" means any tank vessel on departure from or approach to oil terminal facilities or refineries, not equipped with a means of self propulsion.

SS. Tank vessel. "Tank vessel" means any vessel on departure from or approach to oil terminal facilities or refineries, that is constructed or adapted to carry, or that carries, oil in bulk as cargo or cargo residue. For the purpose of this chapter, tank vessel does not include any vessel engaged in oil spill response activities, including response-related training.

TT. Temporarily out of service. "Temporarily out of service" means a facility or portion thereof no longer in use. Facilities or tanks which are used for seasonal storage, for surcharge storage, or for standby storage, are not considered out of service.

UU. Thermal relief. "Thermal relief" means the method of relieving the excess pressure caused by the heating action of the sun on piping and equipment.

VV. Transfer. "Transfer" means both on-loading and off-loading between an oil terminal facility and vessel, vessel and vessel, and oil terminal facility and vehicle.

WW. Transport. "Transport" means to convey oil in or on a vehicle, exclusive of the fuel carried for use in the vehicle.

XX. Transportation pipeline. "Transportation pipeline" means the continuous piping systems used for the intrastate conveyance of oil outside of the boundaries of an oil terminal.

YY. Underway. As used in this chapter, "underway" means that a vessel is not at anchor, or made fast to the shore, or aground.

ZZ. Vehicle. "Vehicle" means a tank truck, stake truck, trailer, semi-trailer, tractor or other conveyance and appurtenances thereto designed for or capable of transporting oil, other than fuel used in the operation of that vehicle.

AAA. Vessel. "Vessel" means every description of water craft or other contrivance used or capable of being used as a means of transportation on water, whether self propelled or otherwise, including, but not limited to, barges and tugs, other than a public vessel.

BBB. Waters of the State. "Waters of the State" means any and all surface waters that are contained within, flow through, or border upon this State or any portion thereof, including, but not limited to, those portions of the Atlantic Ocean within the jurisdiction of the State.

NOTE: The following acronyms used in this chapter stand for the following items:

(1) ANSI. American National Standards Institute

(2) API. American Petroleum Institute

(3) ASME. American Society of Mechanical Engineers

(4) ASTM. American Society of Testing and Materials

(5) CFR. Code of Federal Regulations

(6) GRI. Geosynthetic Research Institute

(7) M.R.S. Maine Revised Statutes

(8) NACE. National Association of Corrosion Engineers

(9) NFPA. National Fire Protection Association

(10) NSF. National Sanitation Foundation

(11) PEI. Petroleum Equipment Institute

(12) POTW. Publicly Owned Treatment Works

(13) STI. Steel Tank Institute

(14) UL. Underwriters Laboratories

(15) OPA 90. Federal Oil Pollution Act of 1990, Public Law 101-380, Section 4202

3. Applicability. This chapter applies to oil terminal facilities, intrastate pipelines, vessels licensed by the Department involved in lightering and vessels on departure from or approach to oil terminal facilities and refineries.

A. Oil Terminal Facilities. This chapter applies to new or existing marine oil terminal facilities used or capable of being used to store more than 1,500 barrels of oil.

(1) Existing facilities. Existing facilities must comply with this chapter, unless otherwise stated in this chapter.

(2) Responsibility. The standards set forth in this chapter do not relieve the owner or operator from responsibility for compliance with other state and federal laws governing the safe storage and handling of oil.

B. Intrastate Pipelines. This chapter applies to intrastate pipelines from terminals to remote locations and includes federal facilities.

C. Vessels. This chapter applies to vessels licensed by the Department pursuant to 38 M.R.S. Section 545(4) to conduct lightering operations in waters of the State of Maine, and tank vessels and tank barges on departure from or approach to oil terminal facilities and refineries licensed by the Department.

Where provisions of this chapter differ from other regulations, the more stringent regulations apply. In the case of any conflict between this chapter and Federal law or with a mandatory rule, regulation, or order of the Federal Government or its agencies where compliance with both is impossible, such Federal law, rule, regulation, or order governs.

4. Oil Discharges

A. Oil Discharge Reporting Procedure. In the event of any discharge prohibited by 38 M.R.S. Section 543, the person, firm or corporation responsible for the discharge shall immediately undertake to remove such discharge as required by 38 M.R.S. Section 548. Responsibility for removal remains with the person, firm or corporation responsible for the illegal discharge. In addition to the regular procedures, the following actions must be taken:

(1) Telephone Report. An initial telephone report of any discharge must be made to the Commissioner as soon as practicable but within two hours. The report must include:

(a) Time of discharge;

(b) Location of discharge;

(c) Type and amount of oil;

(d) Name and telephone number of person making report; and

(e) Other pertinent information.

(2) Written Reports. Once removal of the discharge has been completed, the person, firm or corporation responsible for the discharge shall prepare a complete written report of the occurrence and submit that report to the

Commissioner within 10 days. If circumstances make a complete report impossible, a partial report must be submitted. This report must include, but not be limited to, the following information:

(a) Date, time, and place of discharge;

(b) Name of parties involved;

(c) Amount and type of oil discharged;

(d) Complete description of circumstances causing discharge;

(e) Procedures, methods and precautions instituted to prevent a similar occurrence from recurring;

(f) Recommendations to the Commissioner for changes in rules or operating procedures;

(g) Name and address of any person, firm or corporation that may be affected by the discharge; and

(h) In the case of any oil discharge into the waters of the State from an intrastate pipeline, oil terminal facility, or vessel going to or coming from a facility, the person, firm or corporation responsible for the discharge shall submit a report, in writing, to the Commissioner, setting forth the amount of oil recovered.

(3) Oil Discharge Containment and Clean-up. 38 M.R.S. Section 548 requires any person discharging oil, or its by-products in a manner prohibited by 38 M.R.S. Section 543, to undertake immediately to remove the discharge to the Commissioner's satisfaction. Nothing in the rules or regulations adopted by the Board is intended to relieve any person from this responsibility. Any person who has discharged or caused to be discharged oil as prohibited by law shall contain such oil and remove it from the waters of the State as quickly and completely as possible.

(4) Delegation of Supervisory Authority. The Commissioner or the Commissioner's authorized representative shall receive reports of oil discharges and shall supervise or undertake the removal of any oil discharge, where such actions by the Commissioner are authorized under 38 M.R.S. Section 548, and upon the completion of removal of any discharge the Commissioner or the Commissioner's authorized representative may indicate satisfaction with such removal.

(5) Notification of the Commissioner in no way should delay the proper notification of other authorities such as local and federal agencies

concerned. Protection of life and property by proper notification and action is mandatory and should be accomplished in the most expeditious manner possible.

B. Vessel Cleanup. Before any vessel involved in a transfer operation may leave a land based oil terminal facility, all drip pans, hoses, and other transfer equipment must be cleaned and any oil spilled on the deck, topside piping or equipment, or the exterior of the hull must be removed.

5. Vessel to Vessel Transfer Areas and Hussey Sound Limitation

A. Hussey Sound Limitation. No tank ship or tank barge containing oil cargoes which is actually drawing 40 or more feet shall transit Hussey sound, Casco Bay (port of Portland) regardless of visibility, unless it would be abeam of Soldier's Ledge Buoy within one-half (½) hour of the time of high tide.

B. Vessel to Vessel Transfer Area - Casco Bay. A tank vessel anchorage area is established one mile square starting at Hussey Sound Buoy 12, Lat. 43° 42' 10" North, Long. 70° 90' 46" West(formerly Little Chebeaque Island Shoal Buoy 6)thence one mile true North to Lat. 43° 43' 10" North, Long. 70° 90' 46" West; thence one mile true West to Lat. 43° 43' 10" North, Long. 70° 11' 90" West; thence one mile true South to Lat. 43° 42' 10" North, Long. 70° 11' 90" West; thence one mile true East to the point of origin.

C. Vessel to Vessel Transfer Area - Penobscot Bay. The following tank vessel anchorage areas are established:

(1) The area designated for vessel-to-vessel transfers of bulk oil in Penobscot Bay area is a circle 2 nautical miles in diameter with the center at Latitude 44° 24' 15" North and Longitude 68° 55' 25" West;

(2) A second area designated for vessel-to-vessel transfers of bulk oil in Penobscot Bay area is a circle of one nautical mile in diameter with the center at Latitude 44° 25' 00" North and Longitude 68° 50' 45" West;

D. Vessel Transfers While at Anchor. Vessel to vessel transfers may be carried on only in anchorage areas designated by the Department.

This paragraph does not apply to the transfer of fuel for a vessel's own use.

6. Siting Requirements

A. New Land Based Oil Terminal Facilities

(1) Facility Set-Backs. Every new aboveground oil storage tank operating at pressures less than 2.5 psig must be located in accordance with National Fire Protection Association 30, 1996 Ed.

Vertical tanks storing liquids must be separated in accordance with NFPA 30. Tanks used only for storing Class III B liquids (Flash point at or above 2000 F) may be spaced no less than 3 feet apart unless within a diked area or a drainage path for a tank storing Class I or II liquid in which case the provisions of National Fire Protection Association 30, 1996 Ed. apply.

(2) Facility Location. New oil terminal facilities must not be located within the following areas:

(a) Within 3,000 feet of a surface water body intake used as a public drinking water supply;

(b) Within 600 feet of an existing private drinking water supply, except a facility's own well;

(c) Within 1,000 feet of a significant ground water aquifer; or

(d) Within 1,000 feet of an essential habitat as mapped by the Department of Inland Fisheries and Wildlife, or refuge, park, preserve, or similar site when such site is state or federally designated.

Undeveloped areas of property and non-oil or non-chemical handling areas are not included in the definition of "oil terminal facilities" for the purposes of this paragraph.

(3) A new oil terminal facility located as set forth below is presumed to pose a serious threat to public health or welfare or to the environment such that a license for a facility cannot be issued. The presumption applies if a facility is located:

(a) In a 100 year flood plain, unless suitably elevated to prevent flooding from the 100 year flood, except for piers and piping from a pier to the terminal;

(b) Within 1,000 feet of a freshwater wetland, great pond, or river, stream or brook (as defined in 38 M.R.S. Section 480-B) not used as a public drinking water supply, except for piers and piping from a pier to the terminal;

(c) Within 1,000 feet of the spring high tide line of coastal wetlands (as defined in 38 M.R.S. Section 480-B) with a salt or brackish water regime (salinity equal to or greater than 0.5 parts per 1000) that contain emergent vegetation tolerant of salt water occurring primarily in a salt water or estuarine habitat including, but not limited to, marshes and salt meadows; or

(d) Within 1,000 feet of an eel grass bed.

(4) An applicant seeking a license to establish, construct, alter, or operate a facility in such a location listed in paragraph (3) above may overcome the presumption in paragraph (3) above by persuasive evidence that either:

(a) the facility is unique in some way that allows for compliance with the intent of this chapter through an alternative design, operation, or siting proposal which provides an equivalent level of protection as the siting provision in this chapter would provide; or

(b) the facility environment is unique in some way such that a valuable resource will not be negatively affected by the proposed siting.

B. Existing Land Based Oil Terminal Facilities

(1) Modifications to Existing Facilities. New tanks located inside the existing oil and chemical handling areas of existing facilities are not subject to the siting criteria of section 6 (A). New tanks located outside the existing oil and chemical handling areas are permitted provided they comply with one of the following:

(a) are located in compliance with the siting criteria;

(b) cannot meet all the siting criteria, in which case the owner or operator demonstrated to the Department that the new tank will be constructed in the location which satisfies the greatest number of siting criteria; or

(c) the owner or operator can demonstrate to the Department's satisfaction that although contiguous land is available which meets the siting criteria, compliance with the siting criteria through use of this location would not be economically feasible or would create significant operational problems.

For the purposes of Sections 6(B)(1)(b) and (c) above, land not contiguous to the existing oil and chemical handling area where the oil terminal owner or operator intends to build on land not already owned by the terminal owner or operator would not be included for consideration. A private or public right of way shall not by itself be considered as dividing a property into separate noncontiguous properties.

(2) Abandoned Facilities. Existing facilities that have been abandoned or closed for more than 20 years are prohibited from reuse unless the facility siting complies with the rules of Section 6(A) of this chapter.

7. New Land Based Oil Terminal Facility Minimum Design And Construction Standards

A. Prior Approval. Prior approval for construction of new facilities is required from the Department.

B. Aboveground Oil Storage Tanks

(1) Design and Construction Standards. Aboveground oil storage tanks must be constructed of steel and meet or exceed one of the following design and manufacturing standards:

(a) UL, Standard for Steel Aboveground Tanks for Flammable and Combustible Liquids, No. 142, 1993 Ed. (UL No. 142);

(b) API, Standard No. 650, Welded Steel Tanks for Oil Storage, 10th Ed. (October 1998);

(c) API, Standard No. 620, Recommended Rules for Design and Construction of Large, Welded, Low-Pressure Storage Tanks, 9th Ed. (February 1996).

(2) Prohibited Tanks. Bolted or riveted construction is not acceptable for new or reconstructed tanks.

(3) Leak Detection. Facilities must include a system of visual leak monitoring for tanks greater than 660 gallons between the tank bottom and the impermeable containment as detailed in *API Standard 650, Welded Steel Tanks for oil storage, 10th Ed. (October 1998).*

(4) Corrosion Protection. All tanks must have a cathodic protection system for the portion of the tank in contact with the soil or backfill, in accordance with *API Recommended Practice 651, 2nd Ed. (December 1997), API Standard 650, Welded Steel Tanks for Oil Storage, 10th Ed., (October, 1998) and API Standard 653, Tank Inspection, Repair, Alteration, and Reconstruction, 2nd Ed. (December 1995) or NACE Standard RP0169-1996* unless a cathodic protection assessment indicates that the corrosion rate will not reduce the floor thickness below the minimum allowed in *API 653* before the next required internal inspection date.

(5) Painting. Tanks must be painted in accordance with nationally recognized industry standards, such as the Steel Structures Painting Council publication *Steel Structures Painting, Manual, Volume 1 Good Painting Practice 3rd Ed. (1993).* Insulated tanks are exempt from this requirement.

(6) Tanks on Earthen Base Pads. All tanks on a prepared earthen pad must include the following:

(a) Construction of the base pad leak detection system must meet the standards of *API Standard 650 Welded Steel Tanks for oil storage 10th Ed. (October 1, 1998).*

(b) A release prevention barrier;

(c) The support base must be constructed of compacted, clean, free-draining granular material such as sand, gravel, or crushed stone. The use of cinders and organic material are prohibited.

(d) The support base must be constructed so as to provide for positive drainage of water away from the base;

(e) The support base must be constructed so as to leave at least 12 inches above the general grade (dike floor) after ultimate settlement; and

(f) The surface of the support base must be protected against erosion by good engineering practices.

(7) Tank Spacing. New or relocated or reconstructed tanks must be separated in accordance with National Fire Protection Association 30 1996 Ed. Tanks used only for storing Class III B liquids (Flash point 200F and above) may be spaced no less than 3 feet apart unless within a diked area or a drainage path for a tank storing Class I or II liquid in which case the provisions of NFPA 30 1996 Ed. apply.

(8) Highway Curve Locations. Tanks located near a highway curve must be protected from vehicular collisions.

C. Piping, Valves and Pumps

(1) Fabrication Code. New and replacement piping must be designed, fabricated, tested and maintained in accordance with codes of practice developed by nationally recognized associations such as API, ASME, ANSI, NFPA, PEI or STI. Installation of piping must meet or exceed current codes of practice and be in strict accordance with manufacturer specifications. Piping must be tested for tightness and all deficiencies remedied before the piping is placed in service. References to be followed include: *ANSI, Power piping, B31.1, 1998; ANSI, Process Piping, B31.3, 1996; ANSI, Liquid Transportation Systems for Hydrocarbons, Liquid Petroleum Gas, Anhydrous Ammonia, and Alcohols, B31.4, 1992; API Recommended Practice 1615, Installation of Underground Petroleum Storage Systems, 5th*

Ed., (March 1996); NFPA, Flammable and Combustible Liquids, Code 30, 1996; PEI, Recommended Practices for Installation of Underground Liquid Storage Systems, RP 100-97, 1997.

(2) Identification. All above ground piping and oil fill ports (into tanks and trucks) at multi product oil terminal facilities must be color coded as specified in *API Pub. 1637, Cloro-symbol System to Mark Equipment and Vehicles for Product-Identification at Service stations and Distribution Terminals, 2nd ed. (September 1995).*

(3) Aboveground Piping. Aboveground piping must be adequately supported and be protected from physical damage caused by freezing, frost heaving and vehicular traffic . Aboveground piping must be painted or coated according to nationally recognized industry standards to prevent corrosion.

(4) Underground Piping. Underground piping must be avoided whenever possible. Piping installed after the effective date of this chapter and in contact with the soil or an electrolyte must be adequately protected from corrosion in accordance with codes of practices developed by nationally recognized associations such as NACE or API. Underground lines must have secondary containment with interstitial space monitoring, except that runs in excess of 100 feet that cannot be run aboveground for operational, safety and security reasons may be cathodically protected single walled pipe. References to be followed include: *ANSI, Chemical Plant and Petroleum Refinery Piping, B31.1, 1998; ANSI, Power Plant Piping, B31.3, 1996; ANSI, Liquid Transportation Systems for Hydrocarbons, Liquid Petroleum Gas, Anhydrous Ammonia and Alcohols, B31.4 1992; API, Recommended Practice 1615, Installation of Underground Petroleum Storage Systems , 5th Ed, (March 1996), including Addendum 1(December 1994) Addendum 2 (December 1995) and Addendum 3 (December 1996), NFPA, Flammable and Combustible Liquids, Code 30, 1996; PEI, Recommended Practices for Installation of Underground Liquid Storage Systems, RP 100-97, 1997; API, Cathodic Protection of Aboveground Petroleum Storage Tanks, ANSI/API Standard 651-1997 2nd Ed, 1997; NACE, Control of External Corrosion on Underground or Submerged Metallic Piping System, RP-0169, 1996; NACE, Corrosion Control of Underground Storage Tank Systems by Cathodic Protection, Standard RP-0285, 1995; STI, Recommended Practice for Corrosion Protection of Underground Piping Networks Associated with Liquid Storage and Dispensing System, R892-91, 1991.*

(5) Tank Valves. Each connection to an aboveground oil storage tank through which liquid can normally flow must be provided with a carbon steel valve located as close as practical to the shell of the tank. The tank shell

valve must be kept in the closed position when not in use, except at a staffed facility equipped with a functional continuous tank level monitoring system. At unstaffed facilities, a normally closed automatic valve must be installed immediately downstream of the shell valve on tanks serving a loading rack. Asphalt is exempt from Section 7 C(5).

(6) Pump Leaks. Pumps must be equipped with secondary containment to catch leaks from bearings, packings and seals.

D. Tank - Secondary Containment

(1) Capacity of Spill Containment Dikes. All oil terminal facilities must have diked areas designed, constructed and maintained to prevent oil from entering the waters of the State or adjacent property.

Aboveground tanks must be surrounded by a containment dike with a minimum height of 24 inches, and constructed as follows:

(a) Where a diked area contains one storage tank, the diked area must retain not less than 110% of the capacity of the tank;

(b) Where a diked area contains more than one storage tank, the diked area must retain not less than 110% of the capacity of the largest tank, deducting the volume of the other tanks in the diked area below the top surface of the dike; and

(c) Containment capacity for all facilities must be verified when modifications to the diked areas, or the capacity of the storage tank are made. If no modifications are made, the containment capacity shall be verified every 10 years. Dike walls that have eroded or degraded over time must be regraded or repaired.

(2) Dike Configuration. *The National Fire Protection Association, Flammable and Combustible Liquids, Code 30, 1996* governs dike configuration for new facilities.

(3) Dike Impermeability. New facilities must have secondary containment with the base and walls designed for a permeability rate to water of 1 x 10-7 cm/sec, except where asphalt is the only oil stored in the dike area.

(4) Liner Design Specifications. The applicant must submit to the Department for review and approval complete design plans and specifications for the liner and associated containment structures. The documents must be signed and sealed by a Maine Registered Professional

Engineer. The plans and specifications must include, but are not limited to, the following:

(a) Liner subgrade and cover materials, placement and compaction;

(b) Liner materials, storage, handling, placement, anchoring, penetrations, attachment to structures, and seaming;

(c) The methods of field and laboratory destructive testing as required in paragraph (5) below;

(d) Methods of nondestructive testing of 100% of welded, extruded, or solvent seams; and

(e) A list and description of the manufacturer's oil certifications, installation certifications, and warranties.

(5) Liner Testing. Liner testing must meet the following requirements:

(a) Welded, extruded, or solvent seams for synthetic geomembranes. At a minimum, seam testing must be carried out twice daily at the beginning and end of days when seaming takes place, or whenever seaming personnel change, or when environmental conditions significantly change as determined by the liner specifications;

(b) Moisture content, hydraulic conductivity, and mass per unit area for every 50,000 square feet or per lot of geocomposite liner delivered;

(c) Construction methods and moisture-density zone of acceptance for soil liners to be performed according to a statistically valid method approved by the Department and based on the size of the liner; and

(d) All welded, extruded and solvent seams must be tested by an approved non-destructive method.

Testing methods must conform to nationally recognized standards. If no standards exist, alternative methods must be approved by the Department.

Note: The American Society of Testing and Materials (ASTM), the Geosynthetic Research Institute (GRI), and the National Sanitation Foundation (NSF) are considered nationally recognized standards.

(6) Liner Quality Assurance (QA) Plan. The applicant must submit to the Department for review and approval a liner QA plan which must include, but is not limited to, the following:

(a) A description of how the liner QA plan interfaces with the overall liner and containment structure design plans and specifications;

(b) Qualifications of the construction inspector. The inspector must be fully knowledgeable of the QA plan, independent of the liner manufacturer and fabricator, and empowered by contract to enforce all provisions in the liner QA plan and liner design plans and specifications;

(c) Qualifications of liner fabricator, lead seamer, quality control officer, and site supervisor personnel;

(d) Qualifications of the independent testing laboratory;

(e) The environmental conditions at which seaming or placement of the liner must be stopped or seaming techniques substantially modified;

(f) Seam inspection, rejection, or repair procedures for faulty seams or evidence of a faulty seam, or placement of liner determined through destructive testing, nondestructive testing, or inspection; and

(g) Record keeping and reporting requirements for QA activities.

(7) Compatibility of Geomembrane Liner. Geomembrane liners used for secondary containment must meet a short term compatibility testing (7-28 days) before any new oil is put in the tank.

(8) Liner Installation Standards. All new geomembrane liners shall be installed in accordance with the manufacturers' recommendations. A minimum of 6 inches of fine gravel or sand shall be placed over the liner to protect the liner from damage.

(9) Valve Access. Tank shut-off valves must be accessible during a 24-hour, 25-year rainfall event and under all operating conditions.

(10) Detailed Design. The detailed design of new spill containment dikes must be certified by a professional engineer.

(11) Dike Stairways. Permanent fixed stairways must be provided for access to diked areas to prevent degradation of the dike walls.

E. Facility Drainage Systems

(1) Design. The water collection, drainage, discharge, and oil/water separator system must be designed by a professional engineer and provide for operational stress likely to be encountered in Maine, such as frost action, and a 24-hour, 25-year rainfall. All buried or partially buried oil/water

separators must be of a design and construction (approved by the Department) that will prevent galvanic corrosion.

(2) Oil/Water Separators. In addition oil/water separators must be designed, licensed, operated, and maintained according to 38 M.R.S. Section 413 (Waste Discharge Licenses) if the effluent is discharged directly into the waters of the State. If the effluent will be discharged to a publicly owned treatment works (POTW), the oil/water separator must also be designed, licensed, operated, and maintained according to the local requirements of the POTW (in order to meet their state and local license requirements).

(3) Drain Valves. Drain valves must be easily accessible for closing in an emergency under all conditions of operations. Flapper valves are not acceptable.

(4) Dike Drainage.

(a) Control of drain water from inside a diked area must be from a valve outside the dike area, locked in the closed position except at times of drainage operations under supervision by personnel trained in the proper operations of drains and separators. Drainage control valves may be located inside the dike area at existing facilities where No. 6 oil or asphalt is the only oil being stored in the dike area, provided that these drainage valves are locked in the closed position except during drainage operations under supervision by trained personnel and the dike valves are exercised monthly.

(b) All drainage through the oil/water treatment system from a containment dike must be locked out from discharge except at times of supervised drainage. All drainage must flow through an oil/water separator.

(5) Oil Storage and Handling Area. Facilities must be graded to collect surface run-off and discharge it through an oil/water separator to a location approved by the Department. Such separators must be designed, installed and maintained to handle a 24-hour, 25-year rain fall.

F. Tank Truck and Tank Car Loading and Unloading

(1) Shut-Off Valves. Steel shut-off valves must be provided at the end of all loading and unloading points and be maintained in a locked position except during properly supervised operations. Such valves must be accessible under all conditions of operations.

(2) Hose Spill Preventers. All vehicle loading points must be equipped with spill preventers designed to drain the transfer hose at the end of the transfer procedure.

(a) The spill preventer must be of sufficient size to contain the contents of the hose.

(b) A dry break system approved by the Department may be used in lieu of the spill preventers.

(3) Automated Equipment. The design of the piping, valves, pumps and hoses which convey oil from the above ground storage tanks to the tank truck and/or the railcar loading rock must be "fail-safe" engineered so as to prevent the spill of oil.

(4) End Capping. Top loading arms at truck and rail loading racks must be equipped with a containment device capable of preventing a discharge of oil when not in use or in standby service. Piping used for unloading tank cars or trucks must be securely capped or blank flanged when not in use.

(5) Spill Containment. Tank truck and rail car loading, and unloading areas, except for facilities handling only asphalt, must be provided with impervious secondary containment, that is designed, constructed, and maintained to contain spills in amounts up to the volume of largest compartment of any truck or car vehicle loaded or unloaded at the facility. The secondary containment systems in loading and unloading areas must be designed and constructed to prevent collection of stormwater runoff and must be connected to either a slop tank for removal and disposal or to an oil/water separator.

G. Fire Prevention. All facilities must be designed, built, operated, and maintained in accordance with the *National Fire Protection Association, Flammable and Combustible Liquids, Code 30, 1996*. A terminal facility unable to meet these requirements must file an alternate fire protection plan for approval by the Department.

H. Physical Security

(1) Fencing. All facilities must have a security fence surrounding the facility. New fencing must be at least 6 feet high. Gates must be provided, that are locked except when the facility is in supervised operation or guarded. The Department may approve alternative security measures upon deciding that the alternative fencing or security guarding meets the intent of this chapter.

(2) Lighting. A minimum illumination standard of 50 lux is required for transfer areas, pump areas, and entryways that would likely be the source of leaks by accident or by acts of vandalism, adequate lighting must be provided in accordance with the *Illumination Engineering Society of North America Lighting Handbook, 8th Ed., 1993*.

I. Dock Facility

(1) Transfer Piping. The connection points of the oil transfer piping to the storage tankage, located on the dockside, must have steel shut-off valves and check valves installed to prevent back-flow of oil should failure of dock hoses or other equipment occur.

(2) Spill Containment. All oil transfer points of connection must be provided with a spill containment system designed, constructed, and maintained to contain discharges that may occur from a hose or connection point rupture.

The spill containment system must have a storage capacity of at least:

(a) Two barrels if it serves one or more hoses of 6-inch inside diameter or smaller, or loading arms of 6-inch nominal pipe size diameter or smaller;

(b) Three barrels if it serves one or more hoses with an inside diameter of more than 6 inches, but less than 12 inches, or loading arms with a nominal pipe size diameter of more than 6 inches, but less than 12 inches; and

(c) Four barrels if it serves one or more hoses of 12-inch inside diameter or larger, or loading arms of 12-inch nominal pipe size diameter or larger.

(d) Spill containment must be properly positioned and adequately maintained and an absorber shall be available in case of overflows to minimize the loss of oil. At no time shall the spill containment contents be allowed to spill in the water or surrounding soil. Spill containment must be disposed of in a manner acceptable to the Commissioner.

(3) Requirements for Protection Against Mechanical Damage. Concrete or other portions of pier or wharf structures that are exposed to impact or abrasion by vessels or are subject to damage by floating ice or debris must be protected by an open fender system constructed of wood or other material. Provisions must be made to reduce the impact force exerted on the pier with such details of construction as will reduce damage from ordinary operations to a reasonable minimum.

J. Shop-Fabricated Aboveground Storage Tank Minimum Design and Construction Standards

(1) Shop-Fabricated Aboveground Storage Tanks

(a) Design and Construction Standards. Shop-fabricated aboveground storage tanks used to store flammable or combustible liquids must be constructed of steel and meet or exceed the design requirements of *Flammable and Combustible Liquids, Code 30, National Fire Protection*

Association, 1996. Shop-fabricated aboveground storage tanks used to store non-flammable or non-combustible hazardous substance (as defined by 38 M.R.S. 1362(1)) must be constructed of materials compatible with the material to be stored and designed in accordance with good engineering practices. All shop-fabricated aboveground storage tanks, including any integral secondary containment systems, must be installed according to the manufacturer's recommendations.

(b) Prohibited Tanks. Tanks constructed in accordance with Standard for Steel Inside Tanks for Oil-Burner Fuel, Underwriters Laboratories 80, can only be used to supply fuel to oil-burning equipment.

(c) Secondary Containment. All shop-fabricated aboveground storage tanks must be located in diked areas meeting the requirements of Section 7 (D)(4), or designed with their own integral secondary containment system meeting the standards of one of the following: *Standard for Diked Aboveground Storage Tanks, Steel Tank Institute F911-93; Standard for Aboveground Tanks with Integral Secondary Containment, Steel Tank Institute F921-98; or Insulated Aboveground Tanks for Flammable and Combustible Liquids, Underwriters Laboratories, Standard 2085, 1st ed., 1994.*

(d) Leak Detection. Shop-fabricated aboveground storage tanks must be designed so that the space between the bottom of the tank and the secondary containment can be either visually or electronically monitored.

(e) Corrosion Control. All shop-fabricated aboveground storage tanks must have a cathodic protection system for the portion of the tank in contact with the soils or backfill in accordance with API Recommended Practice 651 *Cathodic Protection of Aboveground Petroleum Storage Tanks, 2nd Ed. December, 1997. Recommended Practices for Installation of Aboveground Storage Systems for Motor Vehicle Fueling, Petroleum Equipment Institute Publication RP200-96; Recommended Practices for External Corrosion Protection of Shop Fabricated Aboveground Tank Floors, Steel Tank Institute STI-R893-89; or Control of External Corrosion on Underground or Submerged Metallic Piping System, National Association of Corrosion Engineers, RP-0169, 1996.*

(f) Overfill Prevention

(i) All shop-fabricated aboveground storage tanks used to store a flammable or combustible liquid with a capacity of over 20,000 gallons or with an integral secondary containment system must have:

a. A device which sounds an audible alarm when the tank reaches 90% of capacity; and

b. A person in charge from the terminal receiving the delivery monitoring the transfer along with the truck driver.

(ii) All shop-fabricated aboveground storage tanks of 20,000 gallons or less used to store a flammable liquid must have one of the following:

a. A device which sounds an audible alarm when the tank reaches 90% of capacity; or

b. A device which automatically stops the flow of the liquid into the tank when the liquid level of the tank reaches 95% of capacity; or

c. A person in charge from the terminal receiving the delivery monitoring the transfer along with the truck driver.

(g) Painting. Tanks must be painted in accordance with the *Steel Structures Painting Council publication Steel Structures Painting, Manual, Volume 1 Good Painting Practice (1993*). Insulated tanks are exempt from this requirement.

(2) Piping, Valves and Pumps

(a) Fabrication Code. All aboveground piping systems must be designed, constructed, installed and maintained in accordance with Section 7(C)(1)

(b) Pump and Valve Leaks. Pumps and valves must be equipped with secondary containment to catch leaks from bearings, packing and seals.

(c) Tank Valves. All shop-fabricated storage tanks connected to the loading rack shall be equipped with a device such as a normally closed solenoid valve that will prevent gravity flow from the tank in the event of a piping breach, unless tank inventory is reconciled daily. Valves on shop-fabricated storage tanks not connected to the loading rack and not in frequent use must be maintained in the closed position.

(d) Underground Piping. Underground piping must be avoided whenever possible. All underground piping must be designed, constructed, installed and maintained in accordance with DEP Chapter 691 or 695.

8. Existing Land Based Oil Terminal Facility Minimum Design And Construction Standards

A. Notification of Work The Department must be notified of substantial modifications, rehabilitation, and new construction including, but not limited to, the installation of new tanks, the construction of new secondary containment, new dikes, and new dike floor liners prior to implementation.

Certification of the designs is required by a State of Maine registered professional engineer or an engineer otherwise working in compliance with Maine's professional regulation statutes.

B. Aboveground Oil Storage Tanks

(1) New Tankage. New aboveground oil storage tanks added to existing terminals must meet the rules and construction standards of Section 7(B) of this chapter. The new tankage may vary from the spacing requirements if an alternate fire plan is approved by the local fire department and the State Fire Marshall.

(2) Prohibit Reuse of Tanks. Existing tanks that have been permanently closed may be reused only if the following conditions are met:

(a) The existing tank must have an ASME code stamp, API nameplate, or UL label; and

(b) The Department shall be provided with satisfactory documentation that the tank has been inspected by a qualified professional engineer and found to meet the specifications of *API Standard 650, 10th Ed. 1998*.

(3) Corrosion Protection. All existing tanks must have a cathodic protection system for the portion of the tank in contact with the soil or backfill, in accordance with *API Recommended Practice 651, 2nd Ed. (December 1997), API Standard 650, Welded Steel Tanks for Oil Storage, 10th Ed. (October 1998) and API Standard 653, Tank Inspections, Repair, Alteration, and reconstruction, 2nd Ed. (December 1995) or NACE Standard RP0169-1996,* unless a cathodic protection assessment indicates that the corrosion rate will not reduce the floor thickness below the minimum allowed in *API 653* before the next required internal inspection date. The cathodic protection system must be installed by November 7, 2004 or when a release prevention barrier is installed, whichever is sooner.

(4) Painting. The exterior tank shell on existing tanks must be painted and maintained in good condition to prevent excessive rusting and or corrosion to the exterior of the tank. Tank painting occurring after November 7, 2000 must be in accordance with nationally recognized industry standards, such as the Steel Structures Painting Council publication *Steel structures Painting Manual, volume 1 Good Paining Practice 3rd Ed. (1993)*. Insulated tanks are exempt from this requirement.

(5) Upgrade and Repair of Tanks. If an aboveground oil storage tank inspection reveals a discharge, excessive corrosion, excessive tank settlement, or any other deficiency which could result in a discharge, the

tank must be repaired to standards equal to or better than the standards of original construction.

(a) Unacceptable levels of corrosion and tank settlement are as defined *in API Recommended Practice 651. 2nd Ed. (December 1997), API Standard 650, Welded Steel Tanks for Oil Storage, 10th Ed, (October 1998) and API Standard 653, Tank Inspection, Repair, Alteration, and Reconstruction, 2nd Ed. (December 1995).*

(b) All riveted and bolted tanks must have seams, including rivets and bolts on the bottoms and first course of shell plates sealed. Heated oil tanks storing #6 oil or asphalt are exempt from this requirement.

(i) An oil terminal owner or operator must notify the Department within 3 days of discovery of a weep. A weep is identified as a film or staining that travels down the tank one complete ring from the rivets, bolts, or seams of a riveted or bolted above ground oil storage tank. The notification must identify the tank and the location of the weep as it appears on the tank. Within 14 days of discovery of the weep the oil terminal facility owner or operator must either drain the tank below the level of the weep or propose an alternate method acceptable to the Department for controlling the weep prior to the weep being properly repaired.

(ii) A weep which comes in contact with the ground surface must be reported to the Department within two hours of its discovery. The oil terminal owner or operator must drain the tank below the level of the weep within 14 days of discovery. The tank can not be filled above the level of the weep until the Department has received a report from the terminal owner or operator demonstrating that the weep has been properly repaired.

(c) Tank liners will not be an acceptable form of tank bottom repair after November 7, 1999 unless provision is made for leak detection between the liner and the repaired steel bottom.

(6) Release Prevention for Tank Bottoms. Release Prevention Barriers (RPB) with leak detection must be provided for all field constructed tank bottoms within 20 years of the effective date of this chapter. Fifty percent (50%) of the field constructed tanks at a facility must meet this standard by November 7, 2009 seventy five (75%), by November 7, 2014 and all tanks by November 7, 2019. Existing asphalt and No. 6 fuel oil tanks are exempt from the requirement for RPB.

(a) An RPB may include steel double bottom, synthetic liner, geocomposite liner, clay liner or existing soils under the tank provided they meet the standard in 8(B)(6)(b) or such system as the Commissioner shall determine provides the same protection from oil migration due to leakage and equivalent leak detection.

(b) Engineered clay or existing soil liners under a tank may serve as RPB if the engineered clay is at least 12 inches thick or the existing soil layer at least 24 inches thick and meets the following water permeability standards:

Gasoline et al 1 x 10-6 cm/sec

Mid Distillates 1 x 10-5 cm/sec

Crude Oil 1 x 10-5 cm/sec

#4, #5 Fuel Oils 1 x 10-4 cm/sec

Permeability of clay or existing soil RPB's must be determined by a professional engineer or certified geologist using a method capable of testing both horizontal and vertical permeabilities. A soil survey plan, test method, testing location and test protocol must be submitted to the Department for approval.

(c) All tanks except existing asphalt and No.6 fuel oil must be fitted with leak detection upon installation of an RPB. Acceptable methods of leak detection are shown in *API Standard 650, Welded Steel Tanks for Oil Storage 10th Ed. (October 1998)*. Tanks using existing soil liners under a tank must have leak detection comprised of permeable sand or gravel of adequate thickness with collection pipes so that a leak can be detected before passing through the existing soil liner, or such system as the Department may find acceptable. The Department will consider criteria such as speed of detection, reliability of both the system, leak detection method and service life in approving an alternate method.

C. Piping, Valves and Pumps

(1) All new piping runs added to, or replacing, existing runs at an existing facility must be constructed in accordance with the requirements of Section 7(C)(1) and 7(C)(4) of this chapter. For purposes of this section, "replacing" means 25 or more feet of the piping run.

(2) Underground Piping. All existing underground piping must be surveyed and shown on a site plan. The plan shall clearly show the location, material, size and estimated burial depth of all underground piping.

(3) Identification. All aboveground piping at multiple oil facilities must be marked with an oil product identification. All fill ports (into tanks or trucks) must be color coded as specified in *API Recommended Practice 1637, Color-*

Symbol System to Mark Equipment and Vehicles for Product Identification at Service Stations and Distribution Terminals, 2nd Ed. (September 1995).

(4) Pipe Supports. Aboveground piping must be adequately supported and protected from physical damage caused by freezing, frost heaving and vehicular traffic. Aboveground piping must be painted or coated according to nationally recognized industry standards to prevent corrosion.

(5) Pressure Relief Pressure relief valves or an alternate pressure venting procedure must be provided on piping that may be blocked in and filled with oil.

(6) Corrosion Protection. Aboveground piping must be painted or coated to prevent corrosion. Underground piping must be cathodically protected in accordance with *NACE Standard RP0169-1996*.

(7) Tank Valves. Each connection to an aboveground oil storage tank through which liquid can normally flow must be provided with a carbon steel valve located as close as practical to the shell of the tank. The tank shell valve must be kept in the closed position when not in use, except at a staffed facility equipped with a functional continuous tank level monitoring system. In addition, a normally closed automatic valve must be installed immediately downstream of the shell valve on tanks serving a loading rack at unstaffed facilities. Asphalt is exempt from Section 8(C)(7).

(8) Impact Protection. Piping must have protective guards where vehicular impact or other physical impact is possible.

(9) Pump Leaks. Pumps must be equipped with secondary containment to catch leaks from bearings, packings and seals.

D. Tank Secondary Containment

(1) All new, reconstructed, or relocated tankage installed in a new diked area at an existing facility must meet the requirements of Section 7(D) of this chapter.

(2) A new tank in an existing diked area must have secondary containment with leak detection for the tank bottom. This can be accomplished through use of a double bottom tank or by providing a new tank base pad that meets the permeability standards of Section 7(D)(3) of this chapter. The remainder of the diked area must meet the requirements of paragraph (5) of this subsection.

(3) Capacity of Spill Containment Dikes. All existing oil terminal facilities must meet the requirements of Section 7(D)(1) of this chapter. Existing facilities where complete diking is prohibited due to space may use an alternative partial remote impounding system. This system shall not allow overland flow of released tank contents on the ground surface and must meet the standards of *NFPA, Flammable and Combustible Liquids Code 30, 1996*

(4) Dike Configuration. The standards of the *NFPA, Flammable and Combustible Liquids, Code 30, 1996,* govern dike configuration for existing facilities as far as practical.

(5) Dike Impermeability. The base and walls of a diked area surrounding an aboveground storage tank must be designed, constructed and maintained in a condition that prevents any release of oil within the diked area from reaching a surface water body within 72 hours.

(a) A site assessment is required under the following conditions:

(i) Any previous release within the diked area has reached surface water within 72 hours; or

(ii) When the documented type and morphology of the soil through which the release must flow and the distance from the diked area to the nearest down gradient surface water body is less than indicated in the table below:

Soil Type Permeability in centimeters per second Distance (feet)

Clay, silt, silt and clay <5 x 10-4 N/A

Silty sand <4 x 10-3 13

Clean find sand <1 x 10-2 28

Clean medium sand <5 x 10-2 45

Clean course sand <2 x 10-1 72

Sand and gravel <3 x 10-1 101

Clean medium gravel <1.4 246

Shale <5 x 10-6 6

Sandstone <2 x 10-3 11

Fractured rock Site-specific evaluation required. Site Assessment Required.

(b) If the site assessment indicates that a release of the specific oil within the diked area will not be prevented from reaching surface water within 72 hours, the diked area must be improved to meet this requirement.

(c) Spill containment dikes at existing facilities must be upgraded if necessary by November 7, 2009;

(d) The detailed design of new or modified secondary containment dikes must be certified by a professional engineer.

(6) Valve Access. Tank shut-off valves must be accessible under a 24-hour, 25-year rainfall and under all operating conditions.

(7) Dike Stairways. Permanent fixed stairways must be provided for access to diked areas to prevent degradation of dike walls.

E. Leak Monitoring and Detection.

(1) The Department may require monitoring wells and leak detection devices at existing facilities known or reasonably suspected as a source of contamination.

(2) Existing monitoring wells must be checked for free phase products annually or as directed by the Department as a licensing requirement of oil terminal facilities.

(3) Monitoring wells must be designed and constructed as described in Appendix A. New monitoring wells must be located to avoid penetrations in any diked area liner.

F. Existing Tank Truck and Tank Car Loading and Unloading Spill Containment

(1) Tank truck loading and unloading areas except for facilities handling only asphalt, must be provided with impervious secondary containment, that is designed, constructed and maintained to contain spills in amounts up to the volume of the largest compartment of any truck loaded or unloaded at the facility. The secondary containment systems in loading and unloading areas must be designed and constructed to prevent the collection of storm water runoff and must be connected to either a slop tank for removal and disposal or to an oil water separator.

(2) Rail car loading and unloading areas, except for facilities handling only asphalt and #6 oil must be equipped with a device that automatically stops

the flow of the liquid into the tank when the liquid level of the tank car reaches 95% of capacity by January 31, 2002 and; be provided with impervious secondary containment designed, constructed and maintained to prevent a discharge from coming in contact with soils and ballast associated with the rail line by January 31, 2006. The secondary containment must be designed to prevent the collection of storm water runoff and must be connected to either a slop tank for removal and disposal or an oil water separator. Storm water drainage from facilities handling only #6 oil and asphalt must be connected to a slop tank or an oil water separator for removal and disposal.

G. Reopening a Closed Facility. A facility that has been closed must meet the standards for existing facilities if reopening within 20 years of the closure date. Any facility reopening after a closure of more than 20 years must meet the standards for a new facility, including the siting standards in Section 6 of this chapter.

H. Other Requirements. All existing oil terminal facilities must meet the requirements of Sections 7 (E), 7(F) (1)-(4), 7(G), 7(H) and 7(I) of this chapter.

I. Shop-Fabricated Tanks

(1) New shop-fabricated tanks must meet the requirements of Section 7 (J). New tanks may vary from the spacing requirements if an alternate fire plan is approved by the local fire department and the State Fire Marshal.

9. Standard Operating Procedures

A. Transfers Between Land Based Oil Terminal Facilities and Vessels

(1) Personnel. For transfers at an oil terminal facility, the facility must provide the transporter with a written transfer procedure. This procedure must be acknowledged in writing by the transporter.

(2) Inspections. Inspections are required at the beginning of each transfer and as needed to verify the tightness of the loading and off loading lines, valves and other attached apparatus. Inspection logs must be kept at the facility for at least 3 years.

(3) Tank Capacity. Persons transferring oil shall assure that the high level alarms on the receiving tank are set at such a level that if an alarm should occur during the oil transfer there would be sufficient time to shut down the oil transfer operation prior to over filling the tank. This must be verified to

the Department's satisfaction by a signed agreement with the local fire department or by demonstrating that there is sufficient shut down time to the Department.

(4) Fire Main Shore Connection. There must be immediately available during any transfer operation at least one international fire main shore connection.

(5) Bonding Cable. Pipelines on wharves must be adequately bonded and grounded if Class I or Class II liquids are handled. If excessive stray electrical currents are encountered, insulating joints must be installed. Bonding and grounding connections on all piping must be located on the wharf side of the hose riser insulating flanges. The bonding cable must incorporate a meter or other suitable positive means of determining a ground. Typical methods for protection against stray current hazards at wharves are illustrated in *API Recommendation Practice, Protection Against Ignitions Arising Out of Static, Lighting, and Stray Currents, 6th Ed. (September 1998)*. Any bonding cable employed between the wharf piping and the vessel must employ an explosion-proof switch as a method of completing the connection.

(6) Safe Transfer Operations. Oil transfer operations are not permitted when any of the following conditions arise:

(a) If any weather-related condition develops that, in the opinion of the dock watchman, terminal supervisor or watch officer, is too severe for operations to be safely continued;

(b) If a fire occurs on the dock, tank vessel, adjacent tank vessel, or in the nearby vicinity;

(c) If a tank vessel should break loose or if another vessel should come alongside which is not under control or is emitting sparks from its stack or is apt to collide or otherwise present a hazard to the tank vessel in berth at the terminal;

(d) If an oil spill occurs aboard the tank vessel, an adjacent vessel, or on the dock or if a leak develops in joints of hoses or piping which cannot be stopped by tightening;

(e) If in the opinion of the terminal supervisor, dock watchman, or watch officer a vapor condition develops aboard or around the tank vessel or dock which would be too serious to continue operations;

(f) If any other emergency occurs which, in the opinion of the watch officer, terminal supervisor, or dock watchman, constitutes a potential hazard to the tank vessel or facilities; or

(g) If at anytime the high level alarm system within the terminal activates to warn of a possible or pending overflow.

(7) Illumination. No person may transfer or cause to be transferred or consent to the transfer of any bulk oil after dark unless the point of transfer is illuminated to a minimum standard of 50 lux.

(8) Open Hatch Transfer. Transfer of oil by means of a hose through an open hatch is prohibited. An exception may be made only when an emergency arises and this is the only means of moving flammable oil from one vessel compartment to another or of unloading oil from the vessel for purposes of reducing or preventing pollution, or for preventing foundering and then only when all possible precautions to prevent discharge to the waters of the State have been taken. The Commissioner or the Commissioner's designee and the local fire department must be notified.

(9) Sample Collection. No terminal operator shall transfer or cause to be transferred or consent to the transfer of any bulk oil until a sample of the oil to be transferred has been collected, identified by proper labeling, and stored in a place acceptable to the Department. Oil terminal facilities with automatic sampling capabilities are not required to presample. The sample must be stored for a minimum of fifteen days. The Department shall determine the information to be provided with each sample and may require chemical analysis of the sample. Sampling must be done in accordance with Appendix B.

(10) Anticipated Transfer. The Department shall be notified at least 12 hours in advance of any transfer of bulk oil by the terminal operator. The notification must include the following information:

(a) Terminal name and location or anchorage if offshore transfer;

(b) Approximate amount of oil to be transferred;

(c) Oil type;

(d) Vessel name; and

(e) Expected time and date of vessel arrival.

Should unusual circumstances make it impossible to provide 12-hour notice, the terminal operator shall notify the Commissioner as soon as possible. Notification is not required for transfer of oil for a vessel's own use.

(11) Declaration of Inspection. A copy of any "Declaration of Inspection" required by the United States Coast Guard for a tank vessel transferring oil at an oil terminal facility must be in the possession of the terminal operator or the operator's representative and must be available to the representative of the Commissioner who shall on demand, be given the opportunity to verify that the condition of the vessel is as stated in the "Declaration of Inspection."

(12) Other Reports and Forms. The oil terminal facility operator shall also complete such other forms, check lists and reports as the Commissioner from time to time may require.

(13) General Safety Provisions

(a) Signs. During the time a tank vessel is in berth, a warning sign carrying letters not less than 2 inches high on a contrasting background must be displayed on dock and near the gangplank. This sign must read substantially as follows: WARNING-NO OPEN LIGHTS, NO SMOKING, NO UNAUTHORIZED VISITORS.

(b) Hazardous Vapor. When in the opinion of the terminal operator or the Commissioner's representative a hazardous vapor condition develops on the dock or on any vessel, all transfer operations involving all such vessels must be stopped and all sources of ignition such as smoking, use of matches, lighters and open flame except boiler fires must be eliminated and prohibited.

(c) Transfer of Sour Crude. An oil terminal facility must take special precautions for the transfer of sour crude oil to minimize the release of vapors during the transfer period.

(d) Multiple Vessel Mooring. No tank vessel may be secured along side another tank vessel at a pier except while taking bunker oil fuel aboard from a lighter. A tow boat must stand by alongside or in the notch during the transfer of bunker fuel from a lighter to a tank vessel. The bunkering lighter must be moved away from the tank vessel immediately after it has pumped its load aboard the tank vessel

(14) Vessel Pre-Transfer Conference. No person shall commence or consent to the commencement of bulk oil transfer operations at an oil terminal

facility unless the following items have been reviewed, agreed upon and complied with by both vessel and facility personnel:

(a) A sufficient number of adequately trained oil terminal facility personnel shall be assigned to be constantly on duty during cargo transfer operations to keep the transfer operation under constant observation to insure immediate action in case of a malfunction;

(b) Cargo sequence for loading or discharging products and the proper pipe for each product must have been established;

(c) The handling rate at which oil will be transferred must have been established. (Reduced rates are required when commencing transfer, changing the lineup, topping off tanks or nearing completion of transfer.) The amount of time to be given when the vessel or terminal desires to start, or stop, or change the rate of flow must have been determined;

(d) A positive communication and signal system must be operable during transfer operations;

(e) The emergency procedures to be followed in order to stop and contain any discharge must have been established;

(f) Vessel and facility personnel responsible for transfer shall be clearly identifiable at all times. Prior to transfer operations, terminal and vessel personnel responsible for transfer shall be made known to each other; and

(g) An oil terminal facility must have written operation guidelines pertaining to dock operations for vessels coming to or along side its dock during abnormal weather conditions.

(15) Transfer Hoses. No person shall transfer or cause to be transferred or consent to the transfer of any oil between an oil carrying vessel and an oil terminal facility unless:

(a) All oil terminal facility transfer hoses must be of a type designed specifically for the oil transferred. Transfer hoses must be tested annually to 1.5 times the maximum working pressure.

(b) As provided for below, each oil terminal facility hose must be marked with:

(i) The products for which the hose may be used or the words "oil service";

(ii) Maximum allowable working pressure;

(iii) Date of manufacture; and

(iv) Date of the latest test required.

This information need not be marked on the hose if it is recorded elsewhere at the facility and the hose is marked to identify it with that information. This log book must be available for inspection by a representative of the Commissioner.

(c) Hoses must be supported so as to avoid crushing or excessive strain. Flanges, joints, and hoses must be checked visually for cracks and wet spots.

(d) Oil terminal facility hose handling rigs must be of a type which allow adjustment for vessel movement and hoses must be long enough so that they are not strained by a movement of the vessel.

(e) Hose ends must be blanked tightly when hoses are moved into position to be connected and also immediately after they are disconnected and drained either into the vessel tanks or into suitable shore receptacles before they are moved away from their connections.

(f) Hoses must not be permitted to chafe on the dock or vessel or be in contact with hot surfaces such as steam pipes or be exposed to any other corrosive sources.

(16) Mooring Lines. Mooring lines must be tended during transfer operations to prevent excessive movement of the vessel.

(17) Fire Main Connections. Sufficient serviceable fire hose to reach all parts of the vessel and dock with approved combination nozzles attached must be connected to the fire main on the vessel and/or on the dock respectively and be made ready for instant use during the time a vessel is in berth. The fire main must have a master valve at the head of the dock so the fire main can be kept dry in winter and wet in summer. The fire main on the dock must be at least 6 inches in diameter. The fire main must be charged at all times to the master valve. An oil terminal facility not meeting these requirements shall file with the Department for approval, an alternate fire protection plan.

(18) Fire Wires. During transfer operations, fore and aft fire wires must be rigged on the offshore side of the vessel for use by tugs in removing vessels from the pier in event of fire.

(19) Vessel to Shore Transfer. No person may transfer or cause to be transferred or consent to the transfer of any bulk oil from any tank vessel to a land based oil terminal facility unless:

(a) All cargo risers not intended for use in the transfer are blanked;

(b) Sea valves connected to the cargo piping and stern loading connections are tightly closed and sealed with a numbered seal which is logged in the log book of the vessel;

(c) Piping and valves in the pump rooms and on deck are checked by the master of the vessel, senior deck officer or deck officer on duty, or licensed tanker man to see that they are properly set for discharging cargo. An additional check must be made for the same purposes each time the setting is changed;

(d) Full rate of discharge is not attained until shore lines are proven clear; and

(e) On completion of transfer operations, hoses or other connecting devices must be drained of the remaining oil. A drip pan must be in place when breaking a connection and the end of the hose or other connecting devices must be blanked off before being moved.

(20) Shore to Vessel Transfer. No person may transfer or cause to be transferred or consent to the transfer of any bulk oil from a land based oil terminal facility to any tank vessel unless:

(a) All sea valves connected to the cargo piping, stern discharge and ballast discharge valves are closed and sealed with a numbered seal which is to be logged in the vessel log book of the vessel and with the responsible vessel officer of the vessel;

(b) All hose riser valves not to be used are closed and blank flanged, and all air valves on headers are closed;

(c) Special attention is paid during the topping off process to the loading rate, the number of tanks open, the danger of air pockets and the inspection of tanks already loading. Notice of the slowdown for topping off must be given to shore personnel; and

(d) Upon completion of loading, all tank valves and loading valves are closed. After draining, hoses must be disconnected and hose risers blanked.

(21) Scuppers. No person may transfer or cause to be transferred or consent to the transfer of any bulk oil between a tank vessel and a land based oil terminal facility unless the scuppers of any such vessel are plugged watertight during the oil transfer operation, except on tank vessels using water for deck cooling. However, it is permissible to remove scupper plugs

as necessary to allow run-off of water provided a vessel crew member stands watch to re-close the scuppers in case of an oil discharge.

(22) Tank Tops and Hatch Covers. When transferring oil, tank tops and hatch covers must be closed. Ullage caps or plugs must only be opened on tanks that are to be loaded or unloaded and all open ullage holes must be covered with flame screens which must be kept in place during the transfer except for the minimum time necessary to observe transfer progress, take samples or take ullage readings. If a tow boat or other vessel such as a bunker barge or lighter is moved along side for the purpose of serving the vessel and if that floating equipment is steam propelled or propelled by an internal combustion engine, tank tops, tank hatches and ullage plugs or caps must be kept open only on those tanks from which oil is being withdrawn and may be kept open only with flame screens in place. When there is no longer any possibility of sparks or other source of ignition, normal procedure may be resumed.

(23) Ports and Doors to Crew Quarters. When loading and unloading oil, all ports and doors facing the cargo decks, or facing a breeze bringing vapors from another vessel must be closed except when necessary to open for passage of personnel.

(24) Blowing of Boiler Tubes. Blowing of boiler tubes or other work on the boilers which may cause sparks or soot from the stacks during transfer operations is prohibited.

(25) Spillage During Transfer. Transfer must cease if a discharge of oil to the waters of the State occurs during such transfer. Transfer may be resumed when, in the judgment of the Commissioner's representative after consultation, if necessary, with the United States Coast Guard or Local Fire, Chief, adequate steps have been taken to control the discharge and to prevent further discharge.

(26) Contingency plan. Each owner or operator of an oil terminal facility must have available for inspection by the Commissioner or an agent of the Commissioner a copy of any oil discharge response plan required to be submitted to the President of the United States under the federal Oil Pollution Control Action of 1990, Public Law 101-380, Section 4202.

(27) Operations Plans. The owner or operator of each oil terminal facility shall have an operations plan available for inspection upon request of the Commissioner or representative of the Commissioner. The operations plan must describe in detail the equipment and procedures used at that terminal for the prevention of oil spills and the protection of the public health, safety, welfare, and environment.

(28) Spill Prevention Control and Countermeasure (SPCC) Plan. This chapter expressly adopts and incorporates by reference all the requirements of the Spill Prevention Control and Countermeasures Plan in 40 CFR Part 112 (July 1, 1998).

B. Booming of Vessels

(1) All tank vessels and tank barges, except those engaged in bunkering operations and actually bunkering a vessel, from which and to which oil and oil by-products are being transferred, must be protected by an oil boom device which must completely enclose the tank vessel and be maintained by anchoring with sufficient anchors at a minimum distance of 50 feet from the vessel to catch and contain oil discharges, except:

(a) When personnel safety conditions, weather, wind, sea, or ice conditions are such that a boom cannot be wholly or partially deployed and the terminal operator reports this fact to the Commissioner. Reporting must be prior to transfer or whenever conditions develop which require removal of the boom. If the Commissioner's offices are closed, reporting must be on the next working day following the transfer; or

(b) When a portion of the oil has a flash point of -45 F or less, and an ignition temperature of 536 F or more, such as gasoline.

(2) The boom used to enclose the tank vessel must be of a type suited to the conditions of wind, currents, and waves found at the transfer site at the time the transfer takes place, and must be capable of retaining the maximum most probable discharge from the tank vessel under the conditions normally found at the transfer site at the time the transfer takes place. Maximum most probable discharge means a discharge of (1) 2,500 barrels of oil for vessel with an oil cargo capacity equal to or greater than 25,000 barrels; or (2) 10% of the vessel's oil cargo capacity for vessel with a capacity of less than 25,000.

(3) If a terminal operator believes it is impossible or wholly impracticable to implement the booming requirement in whole or in part on a regular basis, the operator may apply to the Department for complete or partial exemption from this requirement. The application must set forth in detail the reasons why such complete or partial exception should be granted. The Department may set any reasonable conditions in granting any exemption hereunder.

C. Land Based Oil Terminal Facilities

(1) Inventory Control/Overfill Protection

(a) Inventory Reconciliation. The liquid level in a tank must be gauged at least once every 7 days and the measurements compared to those of the previous readings. A record of the measurements must be maintained for inspection by the Commissioner or representative of the Commissioner. Tank gauging also is required prior to every delivery of oil into a storage tank at a facility.

(b) Mandatory Loss Reporting. Any liquid level measurements that, after reconciliation of inventory, indicate a loss of liquid of at least 0.5% of throughput on a monthly basis, must be immediately investigated and reported to the Commissioner.

(c) Overfill Prevention. Tank overfilling must be prevented by the following measures, except for asphalt tankages:

(i) High liquid level alarm with audible and visual signals; and

(ii) High-high liquid level alarm with audible and visual signals.

(d) Overfill protection systems must be tested before each transfer or monthly, whichever is the least frequent.

(2) Maintenance and Inspection. Prior to operation and as a condition of continued operation of an oil terminal facility, an inspection program must be implemented by the facility operator as follows:

(a) Daily visual inspection of aboveground tanks, piping, equipment and discharge control devices and surrounding areas to detect possible oil and to determine and carry out any maintenance necessary to prevent discharges from occurring. The operator shall make a list of daily inspection procedures and inspection logs available to the Commissioner or representative of the Commissioner.

(b) A documented monthly visual inspection of the facility, including but not limited to, tanks and all ancillary devices (vents, water drawoff, etc.), valves, piping, spill containment dikes and other spill holding areas, oil/water separators and equipment.

(c) Monthly visual tank inspection must include, but not be limited to the following:

(i) Check exterior surfaces of tanks for discharges and maintenance deficiencies;

(ii) Identify cracks, wear, corrosion, thinning, poor maintenance and operating practices, settlement, swelling of tank insulation, malfunctioning equipment, structural and foundation weaknesses; and

(iii) Inspect and monitor discharge detection systems, cathodic protection monitoring or warning systems.

(d) Tank De-watering. Discharge of water from tank bottoms must be to an appropriate onsite or offsite treatment facility. Oil from the tank as part of the water bottom drawoff may be returned to the tank.

(e) Cathodic protection system. A monthly inspection must be performed on any impressed current cathodic protection system. An annual structure to soil and structure to structure potential test must be performed by a cathodic protection tester for impressed current systems as well as annual structure to soil potentials for galvanic systems. Rectifier voltage and current readings must be in the range specified by the manufacturer or installer of the system. All readings and repairs must be documented.

(f) All underground oil piping more than 5 years old must be inspected or tested to verify the integrity of the piping by November 7, 2001 in accordance with *API Standard 570, Piping Inspection Code: Inspection, Repairs, Alternation and Re-rating of In Service Piping Systems, 1st Ed. (June 1993, as supplemented January 1995 and December 1997).* Verification by pressure testing must consist of holding pressure at 1.5 times the maximum operating pressure for a period of one hour on an annual basis. Verification by use of internal inspection devices, designed to verify the structural integrity of the pipe by measuring the pipe wall thickness and indicating geometric irregularities of the piping is an acceptable alternatives provided it is by November 7, 2001 and every 5 years thereafter. If the age of the piping is unknown, it must be tested within 1 year of by November 7, 2000. Pressure testing or internal inspection is not required on underground piping equipped with secondary containment or a leak detection system. The Commissioner may require testing at other times if there is reason to suspect a discharge.

(g) Aboveground piping tightness testing. Tightness testing is required for aboveground piping 10 years after installation and every 5 years thereafter in accordance with *API Standard 570. Piping Inspection Code; inspection , repair alternation and rerouting of in-service piping systems 1st Ed, June 1993, Supplemental 1 January 1995 and Supplemental 2 December 1997.* Aboveground piping must be hydrostatically pressure tested to 1.5 times the maximum operating pressure for a period of one hour. For the purpose of this section a hydrostatic pressure test may be performed using hydrocarbon product or water. Verification by use of internal inspection devices, designed to verify the structural integrity of the pipe by measuring pipe wall thickness and indicating geometric irregularities of the piping, is an acceptable alternative. If the age of the piping is unknown, it must be tested by November 7, 2001 and every 5 years thereafter. If the piping, including insulated piping, can be visually inspected 360 degrees around over its entire length, then tightness testing is not required.

(h) Internal Tank Inspection. All field constructed tanks must have internal inspections as follows:

(i) Tanks without either an RPB or a cathodically protected bottom with an internal bottom liner must have an internal inspection by January 1, 2004, and at least every 10 years thereafter;

(ii) Tanks with an internal tank bottom liner and cathodically protected bottom must have an internal inspection by January 1, 2008, and at least every 10 years thereafter;

(iii) Tanks with an RPB that have no internal tank bottom liner and cathodically protected bottom must have an internal inspection by January 1, 2008, or within 15 years after a prior internal inspection, whichever is later, and at least every 15 years thereafter;

(iv) Tanks with an RPB, an internal tank bottom liner and cathodically protected bottom must have an internal inspection by January 1, 2008, or within 20 years after a prior internal inspection, whichever is later, and at least every 20 years thereafter;

(v) Tanks containing No. 6 fuel oil must have an internal inspection by January 1, 2003, or within 20 years after a prior internal inspection, whichever is later, and at least every 20 years thereafter;

(vi) Tanks containing No. 6 fuel oil with a cathodically protected bottom must have an internal inspection by January 1, 2008, or within 20 years after a prior internal inspection, whichever is later, and at least every 20 years thereafter;

(vii) Tanks containing asphalt must have an external/internal inspection by January 1, 2003, or within 20 years after a prior internal inspection, whichever is later, and at least every 20 years thereafter; and

(viii) Tanks containing asphalt with a cathodically protected bottom must have an external/internal inspection by January 1, 2008, or within 20 years after a prior external/internal inspection, whichever is later, and at least every 20 years thereafter.

Note: API 653 inspections performed prior to the adoption of this chapter and in compliance with all requirements of API 653 including using a certified inspector shall count as the first inspection under this chapter.

(i) Internal inspections must be in accordance with *API 653, Tank Inspection Repair, Alteration and Reconstructions 2nd Ed., December 1995, with Addendum 1 (Dec. 1996)*. If, during the inspection, evidence is found of a change from the original physical condition of the tank, then the suitability of the tank for continued service must be evaluated in accordance with API 653. Internal inspections and suitability for service evaluations must be conducted by an API certified 653 inspector. Inspection records must be kept for review by the Commissioner or representative of the Commissioner. Any hole or failure of a tank or piping must be reported to the Department.

(j) For asphalt tanks the following inspection requirements will, for the purpose of this chapter, meet the intent of API 653, paragraph 4.5, Alternative to Internal Inspection to Determine Bottom Thickness.

(i) Inspections for indications of asphalt seepage and stability of the foundation, such as erosion or fill migration or settlement, must be performed around the exterior perimeter of the tank where the tank floor is flush with the ring wall foundation or pad foundation. For the purposes of this section, the pad foundation refers to earth or concrete.

(ii) Inspections must also be made around the external shell to floor joint for indications of seepage or cracked weld seams.

(iii) If the tank wall or floor is riveted construction, rivets must be inspected for indications of seepage or corrosion which could indicate a rivet losing strength. Insulation must be temporarily removed to allow inspection of rivets at 10 to 16 locations. If the inspection reveals a significant number of leaking rivets, then an expanded detailed inspection plan shall be prepared and submitted to the Department for approval.

Repair of leaking rivets can be made using the best acceptable industry practices at that time. Care must be given to allow for thermal expansion of the shell, rivet and hole in determining the proper repair procedure.

(iv) The tank perimeter must be inspected for indications of tank settling such as floor or shell deformations. If the exterior of the tank is insulated, inspections for shell deformation must be conducted from the interior of the tank. The exterior floor elevations must be checked at 8 evenly spaced locations around the perimeter of the tank using a level. Records of the elevations must be kept for comparison with those gathered at subsequent inspections to detect any long-term settling.

(v) Floor thickness must be measured at 6 to 8 locations distributed throughout the interior bottom. At least one of these points must be within 6 inches of the shell. Asphalt at these points must be removed to bare metal. If there is any evidence of external or internal corrosion of the tank shell or floor, the floor thickness must be measured at the suspected point of minimal remaining floor thickness. Use the minimum reading floor thickness observed as the floor thickness to compare with acceptable minimum thicknesses. If corrosion is present, allowances must be made for future metal loss in determining whether to replace the tank bottom or schedule for the next inspection.

(vi) In the event that local inspections of the tank reveal weld cracks, leaking rivets or other indications of joint failure, the entire floor must be cleaned and inspected, or replaced with a new floor in accordance with API Standard 653.

(vii)The inspection of the balance of the tank should be in accordance with API Standards 650 and 653, as well as any repairs or modifications made.

(3) Steam or Heating Devices. No person may discharge exhaust steam containing oil from any coil or other device used to heat oil directly or indirectly into the waters of the State unless all oil has been removed from such discharge.

(4) Records. Owners or operators shall maintain records documenting required training, inspections, tests, maintenance and repairs. Unless otherwise specified, such records must be kept on file at the facility for three years, and must be available for inspection upon the request of the Commissioner or representative of the Commissioner. In cases involving enforcement action, the three-year period for maintaining such records is automatically extended until the action is finally resolved.

(5) Financial Responsibility Requirements. The Commissioner requires evidence of financial responsibility in the amount of $2 million per facility as a condition of an operating license to ensure proper closure of facilities. Financial responsibility may be established, subject to the approval of the Commissioner, by any one, or by any combination, of the following: insurance, guarantee, surety bond, letter of credit, trust fund or qualification as self-insurer. In determining the adequacy of evidence of financial responsibility, the Commissioner shall consider the criteria in 40 CFR,

Sections 280.95 through 280.99 and 280.102 through 280.103(revised as of July 1, 1998). Any bond filed must be issued by a bonding company authorized to do business in the United States. The Commissioner may change the amount of financial responsibility required if an engineering assessment of probable closure costs indicates such a change in the requirement would be appropriate.

10. Intrastate Pipelines. This chapter expressly adopts and incorporates by reference the regulations concerned with or related to the safety standards and accident reporting requirements for intrastate pipeline facilities used in the transportation of oil in 49 CFR Part 195 (October 1, 1998).

11. Land Based Oil Terminal Facility Staff Training

(1) Persons directly involved in the day to day operations of an oil terminal facility shall be trained and experienced in the proper operations, procedures and required maintenance of the facility, and in procedures to respond to discharges of oil. Each facility must appoint an individual who is responsible for oil discharge prevention and accountable for any oil discharge. This individual shall schedule training sessions for operational personnel to ensure a complete understanding of the federal Spill Prevention, Control and Countermeasures (SPCC) plan, Oil Pollution Act of 1990 (OPA 90) plan, and any applicable contingency plan,

(2) Personnel directly involved in the day to day operations of an oil terminal facility shall be trained annually on the requirements of this chapter

(3) Upon request of the Commissioner, records must be made available indicating the titles, job descriptions, and training summaries of those employees required to receive the training found in paragraph (1) above. All training records shall be kept for a minimum of 3 years.

12. Non-Operating Tanks And Facilities

A. Facility Lockout. When a facility is not in use or under competent supervision for 7 consecutive days, the gates and other access ways must be closed and locked, and the loading valves, filling and gauging pipes must be locked. All tanks, piping, equipment and other devices must be capped or blanked in a manner to prevent their use. Valves that isolate tanks, piping and equipment or that may permit a discharge must be locked in the closed position. Any dedicated electrical or hydraulic control devices serving the tank, piping or other equipment must be locked in the closed position.

B. Temporarily Out of Service. Storage tanks and oil that are temporarily out of service for 12 or more months must be closed as follows:

(1) All oil must be removed from the tank and piping system to the lowest drawoff point. Any waste oil from the tank must be disposed of in accordance with all applicable state and federal requirements:

(2) Tanks must be protected from flotation in accordance with good engineering practices if in a 100-year flood plain;

(3) All openings must be secured and locked. Fill pipes, down loading pipes and any other pipes and openings must be capped or secured to prevent access to, or accidental or unauthorized use or tampering;

(4) Storage tanks or facilities that are temporarily out of service are subject to all requirements of this chapter including, but not limited to, periodic testing, inspection, licensing and reporting requirements; and

(5) Tanks or piping that are temporarily out of service for more than 2 years must be cleaned and rendered free of oil vapors and certified by a marine chemist or a certified industrial hygienist to be gas free. Liquid and sludge must be removed from the tank and connecting pipes.

C. Closure of Tanks Permanently Out of Service. A tank or piping is permanently out of service when it has been temporarily out of service for more than 10 years. Any tank or facility that is permanently out of service must comply with the following:

(1) Provisions must be made for natural breathing of the tank to ensure that the tank remains vapor-free;

(2) All connecting piping must be disconnected and removed or securely capped or plugged. All tank openings must be secured and locked;

(3) Tanks must be marked with the date of when the tank was taken permanently out of service;

(4) Aboveground tanks must be protected from flotation in accordance with good engineering practice; and

(5) A tank that has been permanently out of service may not be reinstalled for petroleum storage unless a suitability for service inspection, in accordance with *API Standard 653, Tank Inspection, Repair, Alteration and Reconstruction, Second Ed., December 1995, with Addendum 1 (December 1996), has been performed.*

D. Facility Closure. At total facility closure, or when a licensee chooses to release the facility license, the owner/operator shall comply with the following:

(1) Prepare a written facility closure plan and implementation schedule within 60 days of the owner/operator's decision to close the oil terminal facility and submit it to the Department for approval. The plan must provide:

(a) For removal of all oil and oil residuals from tanks, discharge control equipment, discharge confinement structures and containment systems. Cleaned tanks can remain in place;

(b) For decontamination or removal of all remaining containers, liners, bases and soil containing or contaminated with oil or oil residuals;

(c) For removal of underground piping; and

(d) A comprehensive piping survey that shows the location of all former pipes, current pipes and abandoned pipes.

(2) In lieu of removal of underground piping, the owner or operator may propose an abandonment plan for review and approval of the Commissioner. The plan must at a minimum include:

(a) A feasibility analysis for removal of underground piping. This analysis must include the rationale for non removal of piping sections including for such reasons as the piping is located beneath permanent structures, is inaccessible to heavy equipment, or is located in such a manner or is of such a great size that it is impractical to remove; and

(b) For piping that is not feasible to remove:

(i) a method for the removal of all product sludges and liquids from the piping;

(ii) a method of filling the piping with solid inert material such that the pipes will not serve as an avenue for discharges of products stored at the facility in the future; and

(iii) a method for capping sections of abandoned piping.

(3) Complete the facility closure plan to the satisfaction of the Department. The Commissioner may require soil, ground water and other testing as a part of the facility closure plan. A facility must not be put into non-oil service without compliance with this requirement. The owner shall not carry out

any facility closure activities until the Commissioner has approved the facility closure plan.

(4) File a written facility closure report with the Department, which must include a certification from an independent engineer that the facility closure was conducted in accordance with the approved facility closure plan and that all regulated substances have been removed or cleaned up to the satisfaction of the Department.

(5) Following the Commissioner's acceptance of the facility closure report, the owner or operator must file an underground piping survey that meets the requirements of Section 12 (D)(1)(d) with the county Registry of Deeds.

(6) If a facility is used as a bulk terminal, it must be operated for two years or more as a bulk terminal before the facility closure requirements for oil terminal facilities no longer apply.

E. Owner Responsibility. When ownership of a facility, or a tank, or piping is unknown, the current property operator is responsible for proper closure of the facility.

13. Licensing

A. Oil Terminal Facility License. No oil terminal facility may transfer or cause to be transferred or consent to the transfer of any oil unless that oil terminal facility holds a valid license issued by the Commissioner pursuant to 38 M.R.S. Sections 544 and 545 and this chapter, and the facility is abiding by all the conditions listed on that license.

After public notice and public hearing November 21, 1977 the above regulation is hereby adopted this 21st day of December, 1977.

STATUTORY AUTHORITY: 38 M.R.S. Section 546 (4)

EFFECTIVE DATE:

October 21, 1971

AMENDED:

July 12, 1973

January 15, 1974

October 1, 1974

February 8, 1978 (Filed 8-10-79)

November 7, 1999 - Except that the Effective dates for Existing facilities shall be as follows:

Section 7(I) is effective February 5, 2000;

Sections 7(E)(2), 7(H), 7(J)(2)(b); 8(C)(3) 8(C)(8) and 8(C)(9) are effective November 7, 2000;

Section 9(C)(1)(c) is effective November 7, 2001; and

Section 7(E)(1), 7(E)(5), 8(F)(1) 8(B)(5)(b), 8(C)(2), 8(C)(6), 8(C)(7) and 8(I) are effective November 7, 2004.

EFFECTIVE DATE (ELECTRONIC CONVERSION):

May 4, 1996

NON-SUBSTANTIVE CORRECTIONS:

April 12, 1999

AMENDED:

March 24, 2001

NON-SUBSTANTIVE CORRECTIONS:

March 16, 2004 - elimination of out-of-place underlines

AMENDED:

April 3, 2016 - definitions 2(AA, CC); changed M.R.S.A. to M.R.S.

APPENDIX A

SPECIFICATIONS AND REQUIREMENTS

FOR VERTICAL GROUND WATER MONITORING WELLS

1. Monitoring wells must be a minimum of 2 inches in diameter.

2. The screened zone must extend at least 10 feet into the water table and at least 5 feet above the ground water surface, as determined at the time of installation; or when installed within a secondary containment liner, the

base of the well screen must extend to within 6 inches of the low point of the liner.

3. The screened portion of a well outside a liner must be a minimum of 15 feet in length and must be factory slotted with a slot size of 0.010 inch.

4. Monitoring wells must be installed with a cap at the bottom of the slotted section of the well.

5. Monitoring wells must be constructed of flush joint, threaded schedule 40 PVC or other types of PVC which have equivalent or greater wall thicknesses.

6. Monitoring wells must be numbered such that all monitoring and testing results may be easily correlated to a specific monitoring well location.

7. All monitoring wells must be equipped with liquid-proof lockable caps.

8. Monitoring wells must be properly distinguished from oil piping using American Petroleum Institute recommended symbols.

9. The area around the screened portion of the well must be surrounded by a porous medium (e.g., sand, gravel, or pea stone).

10. The outside of the well riser must be sealed to the wall of the boring using bentonite or a similar product to a depth of 1.5 feet below ground surface, or to 0.5 feet above the water table, whichever is shallower.

11. Monitoring wells which are located in traffic areas must be cut off at ground level, clearly marked, with a raised limited access cover in accordance with PEI Publication RP100-90 (1990) or properly protected from vehicles.

12. Any damaged monitoring well must be repaired, replaced or properly abandoned as soon as possible after discovery of the damage.

13. Monitoring wells must be installed with a boring rig rather than a backhoe if they are not installed within a containment liner.

14. Unless required by the Department, monitoring wells within a diked area should be properly abandoned, or completed in such a way to prevent leakage of oil via the well should a spill occur within the diked area. Monitoring wells should be abandoned in accordance with the "Handbook of Suggested Practices for Design and Installation of Ground water Monitoring Wells, Aller et al., 1989, EPA document number 600/4-89/034.

15. All wells completed as stick-ups should be completed with a protective steel casing.

APPENDIX B

OIL SAMPLING AND STORAGE PROCEDURE

In general, sampling procedures must conform to the following guidelines in the API Manual of Petroleum Measurement Standards:

Chapter 8.1, Manual Sampling of Petroleum and Oil, Second Ed., October 1989 (ANSI/ASTM D4057-88); and

Chapter 8.2, Automatic Sampling of Petroleum and Oil, First Ed., April 1983; Reaffirmed August 1987 (ANSI/ASTM D4177).

LABELING

A tag or label must be attached to each collected sample. Waterproof and oil proof ink or a pencil hard enough to dent the tag must be used. The following information must be included on the label:

1. Name of the vessel

2. Home port of the vessel

3. Sample date and time

4. Name and signature of the sampler

5. Tank sampled

6. Oil type

7. Oil origin

8. Terminal

Whenever available, the following information also must be provided:

9. API specific gravity

10. Boiling point

11. Sulfur

12. Viscosity

13. Test date

14. Testing lab

15. Analyst

STORAGE

Samples must be subjected to storage conditions as soon as possible. Storage must be in a dark, cool environment. The storage compartment must be secured by lock and key with access assigned to designated personnel. Samples must be stored under these conditions a minimum of (15) days. Due to the potential fire hazard, adequate ventilation and other safety precautions should be observed. Samples must be made available to the Commissioner upon request.

Appendix C

Reference material may be obtained at the following locations:

Reference	**Address**
Standard 620, Design and Construction of Large, Welded, Low Pressure Storage Tanks, 9th Edition, February 1996	American Petroleum Institute 1220 L Street, NW Washington, DC 20005
Standard 650, Welded Steel Tanks for Oil Storage 10th Edition, October, 1998	Same as above
RP 651, Cathodic Protection of Aboveground Storage Tanks 2nd Edition, December 1997 (ANSI/API Std 651-1991) 25 pages, Order Number C65102	Same as above
RP 652, Lining of Aboveground Petroleum Storage Tank Bottoms, 2nd Edition, December 1997 (ANSI/API Std 652-1991) 10 pages, Order Number C65202	Same as above
Std 653, Tank Inspection, Repair, Alteration and Reconstruction 2nd Edition, December 1995-68 pages, Order Number C65302	Same as above
RP 1615, Installation of Underground Petroleum Storage Systems, 5th Edition, March 1996	Same as above
Publication 1637, Using the API Color-Symbol System to Mark Equipment and Vehicles for Product Identification at Services Stations and Distribution Terminals, 2nd edition, September 1995-Includes one 1637A color chart-6 pages, Order Number A16370	Same as above
RP 2003, Protection Against Ignitions Arising out of static, Lightning, and	Same as above

Stray Currents, 6th Edition, September 1998, 45 pages, Order Number K20036,	
Std 570, Piping Inspection Code: Inspection, Repair, Alteration and Rerouting of In-Service Piping Systems, 43 pages, Order Number C57000	Same as above
ASME B31. 1-1998-Power Piping	ASME 22 Law Drive, P.O. Box 2900 Fairfield, NJ 07007-2900
ASME B31.3-1996-Process Piping	Same as above
ASME B31.4-1992-Liquid Transportation Systems for Hydrocarbons, Liquid Petroleum Gas, Anhydrous Ammonia, and Alcohols	Same as above
ASME D4057-95 EI-Manual Sampling of Petroleum and Petroleum Products	ASTM 100 Barr Harbor Drive West Conshohocken, PA 19428
ASTM D4177-95-Methods for the Automatic Sampling of Petroleum and Petroleum Products	Same as above
NACE Standard RP 0285-95-Standard Recommended Practice: Corrosion control of Underground storage tank systems by cathodic protection. Item # 21030	NACE International P.O. Box 218340 Houston, Texas
NACE Standard RP 0169-96 Standard Recommended Practice: Control of External Corrosion on Underground or Submerged Metallic Piping systems-Item # 21001	Same as above
NFPA Standard 30-Flammable and Combustible Liquids Code-1996 Edition	NFPA 11 Tracy Drive Avon, MA 02322-9910
RP-200-96-Recommended Practices for Installation of Aboveground Storage Systems for Motor Vehicle Fueling, 31 pages	Petroleum Equipment Institute

	P.O. Box 2380
	Tulsa, OK 74101
RP 100-97-Recommended Practices for Installation of Underground Liquid Storage System, 31 pages	Same as above
	Steel Tank Institute
Publication # R893-89-Recommend Practice for External Corrosion Protection of Shop Fabricated Aboveground Storage Tank Floors	570 Oakwood Road
	Lake Zurich, IL 60047
Publication #F911-93-Standard for Diked Aboveground Storage Tanks (DAST)	Same as above
Publication F#921-98 Standard for Aboveground Tanks with Integral Secondary Containment	Same as above
	Underwriters Laboratories
UL-80 Standard for Steel Inside Tanks for Oil Burner Fuel-1996	333 Pfingsten Road
	Northbrook, IL 60062-2096
UL-142-Standard for Steel Aboveground Tanks for Flammable and Combustible Liquids-1993	Same as above

UL-2085-Standard for Insulated Aboveground Tanks for Flammable and Combustible Liquids-December 1997	Same as above
	The Illuminating Engineering Society of North America
HB-93-IESNA Lighting Handbook-8th Edition, 989 pages, 1993	120 Wall Street, Fl 17th
	New York, NY 10005
Steel Structures Painting Manual, Volume 1 & 2	Society of Protective Coatings
Volume 1: Good Painting Practice, 3rd Edition, 1993	40 24th Street
Volume 2: systems and Specification, 7th Edition, 1995	Pittsburgh, PA 15222

Steel Structures Painting Manual Publication #:T479	Same as above
Handbook of Suggested Practices for the Design and Installation of Ground-Water Monitoring Wells-EPA Document Number: EPA 600/6-89/034	National Ground Water Association 601 Dempsey Road Westerville, OH 43081
40 CFR Part 112: Spill Prevention Control and Countermeasures Plan Revised-1998	Superintendent of Documents P.O. Box 371954 Pittsburgh, PA 15250 Also obtained on Internet at http://www.access.gpo.gov/nara/rfr/index.html
49 CFR Part 195 Transportation of Hazardous Liquids by Pipeline Revised 1998.	Same as above
46 United States Code, Section 2101 (1997)	Same as above
STI Recommended Practice for Corrosion Protection of Underground Piping Networks associated with Liquid Storage and Dispensing System, R892-91, 1991	Steel Tank Institute 570 Oakwood Road Lake Zurich, IL 60047