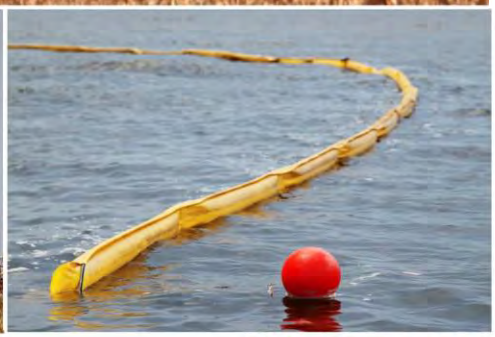
United States Environmental Protection Agency

SPCC Guidance for Regional Inspectors

Office of Emergency Management

August 28, 2013



EPA 550-B-13-001

This document was prepared by the Regulation and Policy Development Division of the EPA Office of Emergency Management under the direction of Mark Howard, Patricia Gioffre, and Troy Swackhammer. Technical research, writing, and editing was provided under EPA Contracts No. 68-W-03-020 and EP09H001292.

Original publication date: November 25, 2005. Revised: August 28, 2013.

The Office of Emergency Management gratefully acknowledges the contributions of EPA's program and regional offices in reviewing and providing comments on this document.

Copies of this document may be obtained online at www.epa.gov/oilspill. In addition, updates to the document will be available online.

Office of Emergency Management (5104A)

EPA 550-B-13-001

Contents

Contents ..... **ii**
List of Tables and Figures ..... **x**
Tables x
Figures x
List of Abbreviations ..... **xiii**
Disclaimer ..... **xvi**
EPA Oil Program Contacts ..... **xvii**
Chapter 1 Introduction **1-1**
1.1 SPCC Background 1-1
1.1.1 Purpose and Scope 1-2
1.1.2 Statutory Framework 1-3
1.2 Regulatory History 1-5
1.2.1 Initial Promulgation and Early Amendments 1-6
1.2.2 SPCC Task Force and GAO Recommendations 1-6
1.2.3 Proposed Revisions – 1991, 1993, and 1997 1-8
1.2.4 2002 Amendments 1-9
1.2.5 Additional Amendments to Streamline the SPCC Rule 1-10
1.2.6 Compliance Date Amendments 1-10
1.3 Revised Rule Provisions 1-14
1.3.1 Rule Organization 1-15
1.3.2 Summary of Major 2002 Revisions 1-17
1.3.3 Summary of 2006 Revisions 1-18
1.3.4 Summary of 2008 Revisions 1-21
1.3.5 Summary of Navigable Waters Ruling 1-25
1.3.6 Summary of the 2009 Amendments to the 2008 Rule 1-25
1.3.7 Effective Date of the 2008 and 2009 Amendments 1-26
1.3.8 Summary of the Milk and Milk Product Container Exemption 1-26
1.4 Using This Guidance 1-26
Chapter 2 SPCC Rule Applicability **2-1**
2.1 Introduction 2-1
2.1.1 Summary of General Applicability 2-1

2.2 Definition of Oil 2-3
2.2.1 Petroleum Oils and Non-Petroleum Oils 2-4
2.2.2 Synthetic Oils 2-4
2.2.3 Animal Fats and Vegetable Oils (AFVO) 2-5
2.2.4 Asphalt 2-5
2.2.5 Natural Gas and Condensate 2-5
2.2.6 Oil and Water Mixtures 2-6
2.2.7 Produced Water 2-6
2.2.8 Hazardous Substances and Hazardous Waste 2-7
2.2.9 Denatured Ethanol used in Renewable Fuels 2-7
2.2.10 Biodiesel and Biodiesel Blends 2-8
2.3 Activities Involving Oil 2-8
2.4 Facilities 2-9
2.4.1 Definition of Facility 2-9
2.4.2 Definitions of Onshore and Offshore Facility 2-11
2.4.3 Definition of Production Facility 2-12
2.4.4 Drilling and Workover Facilities 2-13
2.4.5 Definition of Farm 2-14
2.4.6 Examples of Aggregation or Separation 2-15
2.4.7 Natural Gas Production/Treatment Facilities and Pipelines 2-23
2.5 "Non-Transportation Related" – EPA/DOT Jurisdiction 2-27
2.5.1 Tank Trucks 2-29
2.5.2 Railroad Cars 2-30
2.5.3 Loading/Unloading Activities 2-30
2.5.4 Marine Terminals 2-30
2.5.5 Vessels (Ships/Barges) 2-31
2.5.6 Breakout Tanks 2-31
2.5.7 Motive Power 2-32
2.5.8 Flowlines and Gathering Lines 2-32
2.6 Reasonable Expectation of Discharge to Navigable Waters in Quantities That May Be Harmful 2-33
2.6.1 Definition of "Discharge" and "Discharge as Described in §112.1(b)" 2-33
2.6.2 Reasonable Expectation of Discharge 2-34
2.6.3 Geographic Scope 2-36
2.6.4 Definition of "Navigable Waters" 2-36
2.7 Storage Capacity Thresholds 2-37
2.7.1 Storage Capacity Calculation 2-37
2.7.2 Definition of Storage Capacity 2-37

2.7.3 Tank Re-rating 2-39
2.8 Exemptions to the Requirements of the SPCC Rule 2-40
2.8.1 Permanently Closed Containers 2-40
2.8.2 Offshore Oil Drilling, Production or Workover Facilities Subject to Minerals Management Service Regulations 2-42
2.8.3 Underground Storage Tanks 2-43
2.8.4 Underground Emergency Diesel Generator Tanks at Nuclear Power Stations 2-45
2.8.5 Wastewater Treatment Facilities 2-46
2.8.6 Motive Power 2-47
2.8.7 Hot-mix Asphalt and Hot-mix Asphalt Containers 2-49
2.8.8 Heating Oil Containers at Single-family Residences 2-49
2.8.9 Pesticide Application Equipment and Related Mix Containers 2-50
2.8.10 Intra-Facility Gathering Lines Subject to Department of Transportation (DOT) Requirements 2-50
2.8.11 Milk and Milk Product Containers 2-51
2.8.12 Summary of Exemptions 2-52
2.9 Determination of Applicability by the Regional Administrator 2-52
2.10 SPCC Applicability for Different Types of Containers 2-54
2.10.1 Bulk Storage Container 2-54
2.10.2 Double-walled or Vaulted Tanks or Containers 2-54
2.10.3 Oil-filled Equipment 2-54
2.10.4 Oil-filled Operational Equipment 2-55
2.10.5 Oil-filled Manufacturing Equipment 2-55
2.10.6 Oil-powered Generators (“Gen-sets”) 2-56
2.10.7 Bulk Storage Containers at Tank Battery, Separation and Treating Areas 2-57
2.11 Determination of Applicability of Facility Response Plans 2-59
2.12 Role of the EPA Inspector 2-59
Chapter 3 Environmental Equivalence 3-1
3.1 Introduction 3-1
3.2 Substantive Requirements Subject to the Environmental Equivalence Provision 3-2
3.3 Policy Issues Addressed by Environmental Equivalence 3-5
3.3.1 Facility Drainage 3-6
3.3.2 Corrosion Protection and Leak Testing of Completely Buried Metallic Storage Tanks 3-8
3.3.3 Overfill Prevention 3-10
3.3.4 Facility Transfer Operations, Pumping, and Facility Process Requirements 3-12
3.3.5 Flowline/Intra-Facility Gathering Line Maintenance Program 3-16
3.3.6 Security (Excluding Oil Production Facilities) 3-19
3.3.7 Integrity Testing and Inspection Requirements for Bulk Storage Containers at Onshore Facilities 3-21

3.3.8 Alternative Measures for Containers at Onshore Oil Production Facilities....3-21
3.4 Review of Environmental Equivalence....3-21
3.4.1 Consideration of Costs....3-22
3.4.2 SPCC Plan Documentation....3-22
3.4.3 Role of the EPA Inspector....3-25
Chapter 4 Secondary Containment and Impracticability....4-1
4.1 Introduction....4-1
4.1.1 Overview of Secondary Containment Provisions....4-2
4.2 General Secondary Containment Requirements....4-7
4.2.1 Alternative Measures for General Secondary Containment Requirement: Qualified Oil-Filled Operational Equipment....4-11
4.2.2 Alternative Measures for General Secondary Containment Requirement: Flowlines and Intra-facility Gathering Lines....4-15
4.3 Specific (Sized) Secondary Containment Requirements....4-16
4.3.1 Role of the EPA Inspector in Evaluating Secondary Containment Methods....4-17
4.3.2 Sufficient Freeboard....4-19
4.3.3 Role of the EPA Inspector in Evaluating Sufficient Freeboard....4-23
4.4 Issues Related to Secondary Containment Requirements....4-23
4.4.1 Passive versus Active Measures of Secondary Containment....4-24
4.4.2 “Sufficiently Impervious”....4-29
4.4.3 Facility Drainage (Onshore Facilities)....4-32
4.4.4 Man-made Structures....4-35
4.4.5 Double-walled or Vaulted Tanks or Containers....4-36
4.5 Overview of the Impracticability Determination Provision....4-39
4.5.1 Meaning of “Impracticable”....4-40
4.6 Required Measures when Secondary Containment is Impracticable....4-40
4.6.1 Integrity Testing of Bulk Storage Containers....4-41
4.6.2 Periodic Integrity and Leak Testing of the Valves and Piping....4-41
4.6.3 Oil Spill Contingency Plan and Written Commitment of Resources....4-42
4.6.4 Difference between Contingency Plans and Active Containment Measures....4-44
4.6.5 FRP Implications for Impracticability Determinations....4-44
4.6.6 Role of the EPA Inspector in Reviewing Impracticability Determinations....4-46
4.7 Selected Issues Related to Secondary Containment and Impracticability Determinations....4-50
4.7.1 Piping (General Secondary Containment Requirement, §112.7(c))....4-50
4.7.2 Loading or Unloading Area (or Transfer Area) (General Secondary Containment Requirement, §112.7(c))....4-51
4.7.3 Loading/Unloading Rack (Specific Secondary Containment Requirements, §112.7(h)(1))....4-54

4.7.4 Onshore Bulk Storage Container (Specific Secondary Containment Requirements, §112.8(c)(2) and §112.12(c)(2)) 4-57
4.7.5 Mobile/Portable Containers (Except for Mobile Refuelers and Other Non-Transportation-related Tank Trucks) (Specific Secondary Containment Requirements, §§112.8(c)(11) and 112.12(c)(11)) 4-59
4.7.6 Mobile Refuelers and other Non-transportation-Related Tank Trucks (General Secondary Containment Requirement, §112.7(c)) 4-60
4.7.7 Bulk Storage Containers at Oil Production Facilities (Sized Secondary Containment Requirements, §112.9(c)(2)) 4-61
4.7.8 Onshore Drilling or Workover Equipment (Secondary Containment Requirements, §112.10(c)) 4-62
4.8 Alternative Measures in Lieu of Secondary Containment at Oil Production Facilities 4-63
4.8.1 Flow-through Process Vessels at Oil Production Facilities (General Secondary Containment Requirements, §112.7(c) and Alternative Requirements) 4-63
4.8.2 Produced Water Containers at Oil Production Facilities (General Secondary Containment Requirements, §112.7(c) and Alternative Requirements) 4-65
Chapter 5 Oil/Water Separators 5-1
5.1 Introduction 5-1
5.2 Overview of Provisions Applicable to OWS 5-2
5.2.1 Wastewater Treatment Facilities 5-2
5.2.2 OWS Used for Secondary Containment 5-2
5.2.3 Oil Production Facilities 5-3
5.2.4 Oil Recovery and/or Recycling Facilities 5-3
5.3 OWS Used for Wastewater Treatment 5-2
5.3.1 OWS Used for Wastewater Treatment 5-2
5.3.2 Applicability of the SPCC Rule to OWS Used for Wastewater Treatment 5-3
5.3.3 Wastewater Treatment Exemption Clarification for Dry Gas Production Facilities 5-5
5.4 OWS Used to Meet SPCC Secondary Containment Requirements 5-5
5.4.1 OWS Used to Meet SPCC Secondary Containment Requirements 5-5
5.4.2 Applicability of the SPCC Rule to OWS Used to Meet Specific SPCC Secondary Containment Requirements 5-7
5.5 OWS Used in Oil Production 5-10
5.5.1 OWS Used in Oil Production 5-10
5.5.2 Applicability of the SPCC Rule to OWS Used in Onshore Oil Production 5-12
5.5.3 Applicability of the SPCC Rule to OWS Used in Offshore Oil Production 5-13
5.5.4 Wastewater Treatment Exemption and Produced Water 5-14
5.6 OWS Used in Oil Recovery or Recycling Facilities 5-15
5.7 Documentation Requirements and the Role of the EPA Inspector 5-16
5.7.1 Documentation by Owner/Operator 5-16
5.7.2 Role of the EPA Inspector 5-17

Chapter 6 Facility Diagram and Description 6-1
6.1 Introduction 6-1
6.2 General Facility Description 6-2
6.2.1 Oil Types and Container Capacities 6-2
6.2.2 Discharge Prevention Measures 6-2
6.2.3 Drainage Controls 6-3
6.2.4 Countermeasures 6-3
6.2.5 Disposal Methods 6-3
6.2.6 Contact List 6-4
6.3 Notification Requirements 6-4
6.4 Preparing a Facility Diagram 6-5
6.4.1 Purpose 6-5
6.4.2 Tier I Qualified Facility Exclusion 6-6
6.4.3 Requirements for a Facility Diagram 6-6
6.4.4 Level of Detail 6-8
6.4.5 Fixed Storage Containers 6-8
6.4.6 Mobile or Portable Containers 6-9
6.4.7 Underground Storage Tanks 6-9
6.4.8 Intra-facility Gathering Lines 6-10
6.4.9 Piping and Oil-filled Equipment 6-10
6.4.10 Use of Diagrams Created for Other Programs or Uses 6-12
6.5 Facility Diagram Examples 6-12
6.5.1 Example #1: Bulk Storage and Distribution Facility 6-12
6.5.2 Example #2: Manufacturing Facility 6-16
6.5.3 Example #3: Oil Production Facility 6-18
6.6 Review of a Facility Diagram 6-21
6.6.1 Documentation by Owner/Operator 6-21
6.6.2 Role of the EPA Inspector 6-22
Chapter 7 Inspection, Evaluation, and Testing 7-1
7.1 Introduction 7-1
7.2 Inspection, Evaluation, and Testing under the SPCC Rule 7-2
7.2.1 Summary of Inspection, Evaluation and Integrity Testing Requirements 7-2
7.2.2 Regularly Scheduled Integrity Testing and Inspection of Aboveground Bulk Storage Containers (at Onshore Facilities Other than Oil Production Facilities) 7-10
7.2.3 Removal of Oil Accumulations in Bulk Storage Container Diked Areas 7-14
7.2.4 Integrity Testing and Inspection for AFVO Bulk Storage Containers 7-15
7.2.5 Regular Leak Testing of Completely Buried Tanks 7-19

7.2.6 Brittle Fracture Evaluation of Field-Constructed Aboveground Containers....7-20
7.2.7 Inspections of Piping at Onshore Facilities (Other than Oil Production Facilities)....7-21
7.2.8 Inspection of Drainage Area and Bulk Storage Containers at Onshore Oil Production Facilities....7-22
7.2.9 Alternative Inspection requirements for Flow-through Process Vessels at Oil Production Facilities....7-23
7.2.10 Alternative Inspection Requirements for Produced Water Containers at Oil Production Facilities....7-26
7.2.11 Inspection of Facility Transfer Operations at Onshore Oil Production Facilities....7-29
7.2.12 Maintenance of Flowlines and Intra-Facility Gathering Lines....7-30
7.2.13 Inspection and Corrective Action Requirements at Offshore Facilities....7-32
7.3 Role of Industry Standards and Recommended Practices in Meeting SPCC Requirements....7-33
7.4 Baselining....7-37
7.4.1 Aboveground Bulk Storage Container for Which the Baseline Condition Is Known....7-38
7.4.2 Aboveground Bulk Storage Container for Which the Baseline Condition Is Not Known....7-38
7.5 Specific Circumstances....7-41
7.5.1 Integrity Testing Scenarios for Shop-built Containers....7-42
7.5.2 Integrity Testing and Inspection Requirements for Bulk Storage Containers at Onshore Facilities – Environmental Equivalence....7-44
7.5.3 Suggested Minimum Elements for a PE-Developed Site-Specific Integrity Testing Program (Hybrid Inspection Program)....7-48
7.6 Documentation Requirements and Role of the EPA Inspector....7-51
7.6.1 Evaluating Tank Re-Rating Alterations....7-52
7.6.2 Evaluating Inspection, Evaluation and Testing Programs....7-56
7.7 Summary of Industry Standards and Regulations....7-60
7.7.1 API Standard 653 – Tank Inspection, Repair, Alteration, and Reconstruction....7-62
7.7.2 STI Standard SP001 – Standard for the Inspection of Aboveground Storage Tanks....7-64
7.7.3 STI Standard SP031 - Standard for Repair of Shop Fabricated Aboveground Tanks for Storage of Combustible & Flammable Liquids....7-66
7.7.4 API Recommended Practice 575 – Guidelines and Methods for Inspection of Existing Atmospheric and Low-Pressure Storage Tanks....7-67
7.7.5 API Recommended Practice 12R1 – Recommended Practice for Setting, Maintenance, Inspection, Operation, and Repair of Tanks in Oil Production Service....7-68
7.7.6 API 570 – Piping Inspection Code: In-Service Inspection, Rating, Repair, and Alteration, of Piping Systems....7-69
7.7.7 API Recommended Practice 574 – Inspection Practices for Piping System Components....7-71
7.7.8 API Recommended Practice 1110 – Pressure Testing of Steel Pipelines for the Transportation of Gas, Petroleum Gas, Hazardous Liquids, Highly Volatile Liquids or Carbon Dioxide....7-72
7.7.9 API Recommended Practice 579-1/ASME FFS-1, Fitness-for-Service, Part 3....7-73
7.7.10 API Standard 2610 – Design, Construction, Operation, Maintenance, and Inspection of Terminal and Tank Facilities....7-74

7.7.11 RP FTPI 2007-1 Recommended Practice for the In-service Inspections of Aboveground Atmospheric Fiberglass Reinforced Plastic Tanks and Vessels 7-75
7.7.12 ASME B31.3 – Process Piping 7-76
7.7.13 ASME Code for Pressure Piping B31.4-2006 – Pipeline Transportation Systems for Liquid Hydrocarbons and Other Liquids 7-77
7.7.14 DOT 49 CFR part 180.605 – Requirements for Periodic Testing, Inspection, and Repair of Portable Tanks and Other Portable Containers 7-78
7.7.15 FAA Advisory Circular 150/5230-4A – Aircraft Fuel Storage, Handling, and Dispensing on Airports 7-79
7.7.16 FAA Advisory Circular 150/5210-20 – Ground Vehicle Operations on Airports 7-79
Index 7-1
Appendix A: CWA 311(j)(1)(c) 1
Appendix B: Selected Regulations 1
Appendix C: Summary of Revised Rule Provisions 1
Appendix D: Sample Bulk Storage Facility Plan 1
Appendix E: Sample Production Facility Plan 1
Appendix F: Sample Contingency Plan 1
Appendix G: SPCC Inspection Checklists 1
Appendix H: Other Policy Documents 1

List of Tables and Figures

Tables

Table 2-1: Examples of some oil-related activities that may be regulated under 40 CFR part 112. 2-9

Table 2-2: Examples of transportation-related and non-transportation-related facilities from the 1971 DOT-EPA MOU. 2-28

Table 2-3: Summary of oil storage capacity calculation as described in §112.1(d)(2)(i) and (ii). 2-52

Table 2-4: Process for an RA determination of SPCC applicability and appeals. 2-53

Table 3-1: Requirements eligible for environmental equivalence at all facilities. 3-3

Table 3-2: Requirements eligible for environmental equivalence at onshore facilities (excluding oil production). 3-4

Table 3-3: Requirements eligible for environmental equivalence at onshore and offshore oil production, drilling, and workover facilities. 3-5

Table 3-4: Summary of inspection and leak testing elements of an API-570 program for unprotected buried piping – additional inspection and testing requirements are specified in API 570 (refer to the full text of API 570 for details). 3-15

Table 3-5: SPCC provisions subject to environmentally equivalent measures under §112.7(a)(2). 3-27

Table 4-1: Secondary containment provisions in 40 CFR part 112. 4-3

Table 4-2: Example methods of secondary containment listed in §112.7(c). 4-9

Table 4-3: Reportable discharge history criterion for oil-filled operational equipment. 4-12

Table 5-1: SPCC rule applicability for various uses of OWS. 5-1

Table 7-1: Summary of SPCC inspection, evaluation, and integrity testing program provisions and associated recordkeeping requirements. 7-3

Table 7-2: Summary of industry standards and recommended practices (RP) for ASTs. 7-35

Table 7-3: Summary of industry standards and recommended practices (RP) for piping, valves, and appurtenances. 7-36

Table 7-4: Owner/Operator tank inspection checklist (from Appendix F of 40 CFR part 112). 7-51

Table 7-5: Summary of facility components covered in industry standards for inspection, evaluation, and testing. 7-61

Figures

Figure 1-1: Aboveground storage tank in Floreffe, Pennsylvania. 1-7

Figure 1-2: Graphical representation of 40 CFR part 112 sections. 1-17

Figure 2-1: Separation of tracts at a farm. 2-16

Figure 2-2: Separation of parcels at an oil production facility. 2-18

Figure 2-3: Aggregation of equipment at an oil production facility. 2-20

Figure 2-4: Mile-long flowline at an oil production facility. 2-20

Figure 2-5: Separation of areas at a military base (or other large facility). 2-21
Figure 2-6: Separation of functions at a dual-purpose facility. 2-22
Figure 2-7: Separation of equipment on private property. 2-23
Figure 2-8: Summary of applicability flowchart. 2-60
Figure 2-9: Applicability assessment worksheet. 2-61
Figure 3-1: Fencing around oil storage area. 3-20
Figure 3-2: Example 1: Insufficient Documentation of Environmentally Equivalent Protection for Drainage of Diked Areas (§112.8(b)(1) and §112.8(b)(2)). 3-23
Figure 3-3: Example 2: Sufficient Documentation of Environmentally Equivalent Protection for Drainage of Diked Areas (§112.8(b)(1) and §112.8(b)(2)). 3-24
Figure 4-1: Secondary containment provisions in 40 CFR part 112 related to onshore storage facilities (§§112.7 and 112.8 or 112.12). 4-4
Figure 4-2: Secondary containment provisions in 40 CFR part 112 related to onshore oil production facilities (§§112.7 and 112.9). 4-5
Figure 4-3: Secondary containment provisions in 40 CFR part 112 related to onshore oil drilling and workover facilities (§§112.7 and 112.10). 4-6
Figure 4-4: Secondary containment provisions in 40 CFR part 112 related to offshore oil drilling, production, and workover facilities (§§112.7 and 112.11). 4-7
Figure 4-5: Sample calculation of containment size, using two design criteria. 4-21
Figure 4-6: Sample secondary containment calculations, for multiple tanks in a containment area. 4-22
Figure 4-7: Example of inadequate impracticability determination: Bulk Storage Containers 4-47
Figure 4-8: Example of adequate impracticability determination: Bulk Storage Containers 4-47
Figure 4-9: Checklist of required components of state, local, and regional oil removal contingency plans. Please refer to the complete text of 40 CFR §109.5. 4-49
Figure 4-10: Sample calculation of appropriate general secondary containment capacity at a transfer area. 4-53
Figure 4-11: Facility with separate unloading area and loading rack. The tank unloading area is subject to §112.7(c). The tank truck loading rack is subject to §112.7(h)(1). 4-56
Figure 4-12: Facility with co-located unloading area and loading rack. This containment area is designed to meet the more stringent §112.7(h)(1) provision. 4-57
Figure 4-13: List of SPCC requirements eligible for impracticability determinations. 4-1
Figure 5-1: OWS subject to wastewater treatment exemption. 5-4
Figure 5-2: OWS used to satisfy SPCC rule requirements. 5-1
Figure 5-3: OWS at oil production facilities. 5-2
Figure 5-4: OWS at oil recovery and/or recycling facilities. 5-1
Figure 5-5: Standard gravity oil/water separator. 5-2
Figure 5-6: Enhanced gravity oil/water separator. 5-3
Figure 5-7: Example calculation of secondary containment for a drum storage area using an oil/water separator. 5-9
Figure 5-8: Low pressure free-water knockout. 5-11
Figure 5-9: Two-phase oil/water separator. 5-11

Figure 5-10: Gun barrel oil/water separator. 5-11
Figure 5-11: Three-phase oil/water separator. 5-11
Figure 6-1: Example of a facility diagram showing how manufacturing equipment could be represented. Note that more detailed diagrams would need to be available at the facility. 6-11
Figure 6-2: Example showing how a complex piping area could be represented in a facility diagram. Note that more detailed diagrams would need to be available at the facility. 6-11
Figure 6-3: Example facility diagram, including a loading rack and a separate loading area. 6-14
Figure 6-4: Example facility diagram, including oil-filled equipment, complex piping, and completely buried storage tanks. 6-17
Figure 6-5: Example facility diagram for an oil production facility. 6-20
Figure 6-6: Example general facility location diagram for an oil production facility. 6-21
Figure 7-1: Example baselining plan to determine the integrity testing and inspection schedule using API 653. 7-40
Figure 7-2: Example baselining plan to determine the integrity testing and inspection schedule using STI SP001. 7-41
Figure 7-3: Shop-built containers elevated on saddles. 7-43
Figure 7-4: Summary of integrity testing and inspection program documentation for bulk storage containers at onshore facilities, by type of SPCC Plan and standard applicability case. 7-58

List of Abbreviations

AC	Asphalt cement
API	American Petroleum Institute
AFVO	Animal Fats and Vegetable Oils
ASME	American Society of Mechanical Engineers
ASNT	American Society for Non-Destructive Testing
AST	Aboveground storage tank
ASTM	American Society for Testing and Materials
ATG	Automatic Tank Gauge
BMP	Best management practice
BOEM	Bureau of Ocean Energy Management
BSEE	Bureau of Safety and Environmental Enforcement
CERCLA	Comprehensive Environmental Response, Compensation, and Liability Act
CFR	Code of Federal Regulations
CRDM	Continuous release detection method
CWA	Clean Water Act
DOI	U.S. Department of the Interior
DOT	U.S. Department of Transportation
E&P	Extraction and production
EO	Executive Order
EORRA	Edible Oil Regulatory Reform Act
EPA	U.S. Environmental Protection Agency
ERNS	Emergency Response Notification System
FAA	Federal Aviation Administration
FDA	Food and Drug Administration
FIFRA	Federal Insecticide, Fungicide, and Rodenticide Act
FR	Federal Register
FRP	Facility Response Plan

FTPI	Fiberglass Tank and Pipe Institute
FWPCA	Federal Water Pollution Control Act
GAO	Government Accountability Office
HMA	Hot Mix Asphalt
IBC	Intermediate Bulk Container
LACT	Lease automatic custody transfer
MIC	Microbial Influenced Corrosion
MFL	Magnetic Flux Leakage
MMS	Minerals Management Service
MOU	Memorandum of Understanding
MSO	Marine Safety Office
MTR	Marine transportation-related [facility]
NACE	National Association of Corrosion Engineers
NASS	National Agricultural Statistics Service
NEPA	National Environmental Policy Act
NCP	National Contingency Plan
NDE	Non-destructive examination
NFPA	National Fire Protection Association
NODA	Notice of Data Availability
NPDES	National Pollutant Discharge Elimination System
NRC	National Response Center
NRC	Nuclear Regulatory Commission
OEM	Office of Emergency Management
OMB	Office of Management and Budget
OPA	Oil Pollution Act of 1990 (OPA)
OSHA	Occupational Safety and Health Administration
OWS	Oil/water separator
PE	Professional Engineer
PEI	Petroleum Equipment Institute
PMAA	Petroleum Marketers Association of America
PMO	Pasteurized Milk Ordinance

POTW	Publicly owned treatment work
PSM	Process Safety Management
RBI	Risk-based inspection
RCRA	Resource Conservation and Recovery Act
RA	Regional Administrator
RP	Recommended Practice
RPDD	Regulatory and Policy Development Division
SCADA	Supervisory Control and Data Acquisition [system]
SPCC	Spill Prevention, Control, and Countermeasure
STI	Steel Tank Institute
UIC	Underground Injection Control
UL	Underwriters Laboratories
ULC	Underwriters Laboratories of Canada
UN	United Nations
USCG	U.S. Coast Guard
UST	Underground storage tank
UT	Ultrasonic Testing
UTS	Ultrasonic Thickness Scan
UTT	Ultrasonic Thickness Testing
WQIA	Water Quality Improvement Act

Disclaimer

This document provides guidance to EPA inspectors, to owners and operators of facilities that may be subject to the requirements of the Spill Prevention, Control, and Countermeasure (SPCC) rule (40 CFR Part 112) and to the general public on how EPA intends the SPCC rule to be implemented. The guidance is designed to facilitate nationally-consistent implementation of the SPCC rule.

The statutory provisions and EPA regulations described in this guidance document contain legally binding requirements. This guidance document does not substitute for those provisions or regulations, nor is it a regulation itself. In the event of a conflict between the discussion in this document and any statute or regulation, this document would not be controlling. The guidance does not impose legally binding requirements on EPA or the regulated community, and might not apply to a particular situation based upon the circumstances. The word “should” as used in this guidance is intended solely to recommend or suggest, in contrast to “must” or “shall” which are used when restating regulatory requirements. Similarly, model SPCC Plans in Appendices D, E, and F, as well as examples of SPCC Plan language in the guidance, are provided as suggestions and illustrations only. While this guidance document indicates EPA's preferred approach to assure effective implementation of legal requirements, EPA retains the discretion to adopt approaches on a case-by-case basis that differ from this guidance where appropriate. Any decisions regarding a particular facility will be made based on the statute and regulations.

References or links to information cited throughout this guidance are subject to change. Rule provisions and addresses provided in this guidance are current as of August 2013. This guidance is a living document and may be revised periodically without public notice. This document will be revised, as necessary, to reflect any relevant future regulatory amendments. Interested parties are free to raise questions and objections about the substance of this guidance and the appropriateness of the application of this guidance to a particular situation. EPA welcomes public comments on this document at any time and will consider those comments in any future revision of this guidance document.

EPA Oil Program Contacts

For more information on the Spill Prevention, Control, and Countermeasure rule, or to contact U.S. EPA headquarters and regional offices about this guidance or related issues, please refer to the following contact information.

Contact information is also provided for the National Response Center, the sole national point of contact for reporting all oil, chemical, radiological, biological, and etiological discharges into the environment anywhere in the United States and its territories.

Superfund, TRI, EPCRA, RMP and Oil Information Center

The Superfund, TRI, EPCRA, RMP and Oil Information Center is a publicly accessible service that provides up-to-date information on several EPA programs. The Information Center does not provide regulatory interpretations, but maintains up-to-date information on the availability of publications and other resources. The Information Center is open Monday – Friday from 10:00 a.m. - 5:00 p.m. Eastern Time (except federal holidays).

Toll free: (800) 424-9346

In the Washington, DC, area: (703) 412-9810

TDD (800) 553-7672

TDD in the Washington, D.C. area: (703) 412-3323

http://www.epa.gov/superfund/contacts/infocenter/index.htm

U.S. EPA Headquarters

The EPA Office of Emergency Management (OEM) is responsible for EPA's emergency prevention, preparedness, and response duties, including the Oil Program.

Office of Emergency Management

Regulatory and Policy Development Division (RPDD)

William Jefferson Clinton Federal Building – Mail Code 5104A

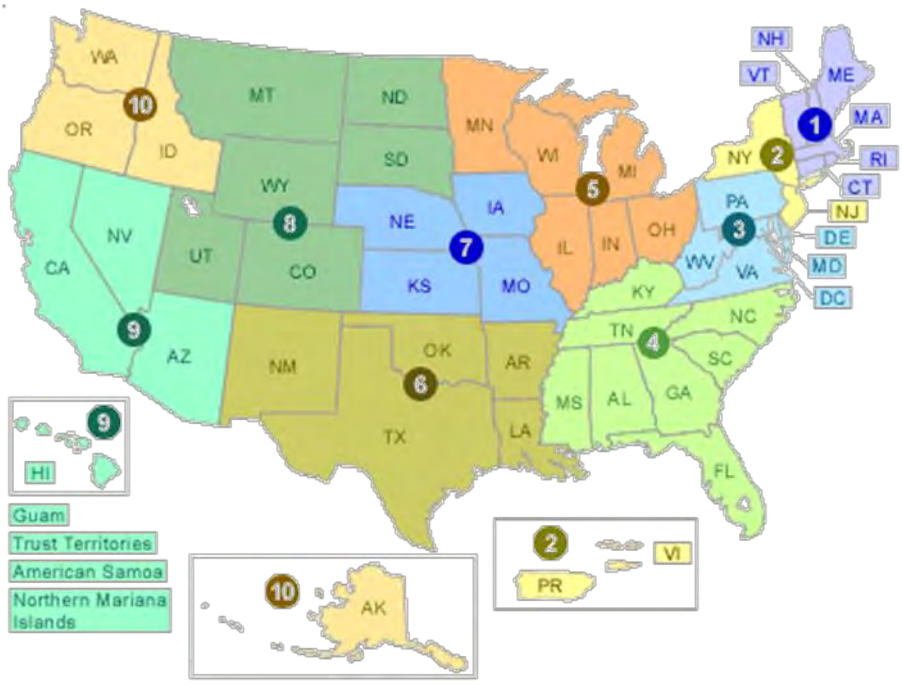
1200 Pennsylvania Avenue, Washington, DC 20460

202-564-8600

www.epa.gov/oilspill

oilinfo@epa.gov

U.S. EPA Regional Offices



Region 1 *– CT, ME, MA, NH, RI, VT*
5 Post Office Square, Suite 100
Mail Code OSRR02-2
Boston, MA 02109-3912
(617)918-1252
(617)918-1111

Region 2 *– NJ, NY, PR, USVI*
2890 Woodbridge Avenue
Building 205 (MS211)
Edison, NJ 08837-3679
(732)906-6964
(732)906-6198

Region 3 *– DE, DC, MD, PA, VA, WV*
1650 Arch Street (3HS61)
Philadelphia, PA 19103-2029
(215)814-5000
(800)438-2474

Region 4 *– AL, FL, GA, KY, MS, NC, SC, TN*
61 Forsyth Street
Atlanta, GA 30365-3415
(404)562-9900

Region 5 *– IL, IN, MI, MN, OH, WI*
77 West Jackson Boulevard (SC-5J)
Chicago, IL 60604-3590
(312)353-2000

Region 6 *– AR, LA, NM, OK, TX*
1445 Ross Avenue (6SF-RO)
Dallas, TX 75202-2733
(214)665-2200

Region 7 *– IA, KS, MO, NE*
11201 Renner Blvd.
Lenexa, KS 66219
(913)551-7003

Region 8 *– CO, MT, ND, SD, UT, WY*
1595 Wynkoop St.
Denver, CO 80202-1129
(800)227-8917

Region 9 *– AZ, CA, HI, NV, AS, GU, CNMI*
75 Hawthorne Street (ENF-3-2)
San Francisco, CA 94105
(415) 972-3000

Region 10 *– AK, ID, OR, WA*
1200 6th Avenue (ECL-116)
Suite 900
Seattle, WA 98101
(800)424-4372
(503)326-2917

Alaska
U.S. EPA Alaska Operations Office
Federal Building/ Room 537
222 West 7th Ave. #19
Anchorage, AK 99513-7588

National Response Center

The National Response Center (NRC) is the sole federal point of contact for reporting oil, chemical, radiological, biological, and etiological discharges into the environment anywhere in the United States and its territories. The NRC operates 24 hours a day, 7 days a week, 365 days a year.

United States Coast Guard (CG-MER-3)

2100 2nd Street, SW Stop 7238

Washington, DC 20593-7238

(800) 424-8802

(202) 267-2675

Fax: 202-267-1322

TDD: 202-267-4477

http://www.nrc.uscg.mil

Chapter 1 Introduction

In accordance with the Oil Pollution Prevention regulation at 40 CFR part 112, the U.S. Environmental Protection Agency (EPA) requires certain facilities to prepare, amend, and implement Spill Prevention, Control, and Countermeasure (SPCC) Plans. The regulation is largely performance-based, which allows flexibility in meeting the rule requirements to prevent discharges of oil to navigable waters or adjoining shorelines.[1] The SPCC rule was promulgated in 1973, with significant amendments published in 2002. EPA finalized additional revisions in 2006, 2008, 2009, and 2011. EPA developed this guidance to assist regional inspectors in implementing the SPCC program and in understanding its applicability, and to help clarify the role of the inspector in reviewing a facility's implementation of performance-based flexibility provisions, such as environmental equivalence and impracticability.

This chapter provides a basic introduction to the SPCC rule and is organized as follows:

- **Section 1.1** describes the rule and its statutory framework.
- **Section 1.2** describes the rule's regulatory history, including the amendments since 2002 and compliance dates.
- **Section 1.3** provides further detail on each of the amendments.
- **Section 1.4** provides the reader with tips on how to use this guidance.

1.1 SPCC Background

The Oil Pollution Prevention regulation promulgated under the authority of §311 of the Federal Water Pollution Control Act, or Clean Water Act (CWA) sets forth requirements for prevention of, preparedness for, and response to oil discharges at specific non-transportation-related facilities. To prevent oil from reaching navigable waters or adjoining shorelines, and to contain discharges of oil, the regulation requires these facilities to develop and implement SPCC Plans and establishes procedures, methods, and equipment requirements.

§112.2

Spill Prevention, Control, and Countermeasure Plan; SPCC Plan, or Plan means the document required by §112.3 that details the equipment, workforce, procedures, and steps to prevent, control, and provide adequate countermeasures to a discharge.

Note: The above text is an excerpt of the SPCC rule. Refer to 40 CFR part 112 for the full text of the rule.

[1] EPA uses the phrase "navigable waters or adjoining shorelines" throughout this Guidance as shorthand for the jurisdiction description in Section 311(b)(1) of the Clean Water Act which prohibits the discharge of oil "into or upon the navigable waters of the United States, adjoining shorelines, or into or upon the waters of the contiguous zone, or in connection with activities under the Outer Continental Shelf Lands Act or the Deepwater Port Act of 1974, or which may affect natural resources belonging to, appertaining to, or under the exclusive management authority of the United States (including resources under the Magnuson-Stevens Fishery Conservation and Management Act of 1976)."

1.1.1 Purpose and Scope

Subparts A through C of 40 CFR part 112 are often referred to as the "SPCC rule." Focusing primarily on facility-related oil spill prevention, preparedness, and response, the SPCC rule is designed to protect public health, public welfare, and the environment from potential harmful effects of oil discharges to navigable waters or adjoining shorelines. The rule requires certain facilities that could reasonably be expected to discharge oil in quantities that may be harmful into navigable waters of the United States or adjoining shorelines to develop and implement SPCC Plans. The Plans ensure that these facilities put in place containment, controls, and countermeasures that will prevent oil discharges. The requirements to develop, implement, and revise the SPCC Plan, as well as train employees to carry it out, allow owners and operators to achieve the goal of preventing, preparing for, and responding to oil discharges that threaten navigable waters and adjoining shorelines.

Part 112 also includes requirements for Facility Response Plans (FRPs) that address oil discharge preparedness requirements for a subset of SPCC-regulated facilities. These requirements define who must prepare and submit an FRP and what must be included in the Plan, and are found in Subpart D of 40 CFR part 112 (and related appendices). These requirements are often referred to as the "FRP rule."[2] Although the SPCC and FRP rules are related, this guidance specifically covers the prevention requirements of the SPCC rule (40 CFR part 112, subparts A, B, and C).

The SPCC rule implements EPA's authority under CWA §311, as delegated through various Executive Orders. Pursuant to Executive Order 11548, EPA was delegated the authority to regulate non-transportation-related onshore and offshore facilities that could reasonably be expected to discharge oil into navigable waters of the United States or adjoining shorelines (35 FR 11677, July 22, 1970). Executive Order 11548 was superseded by Executive Orders 11735 and 12777, respectively (38 FR 21243, August 7, 1973; 56 FR 54757, October 22, 1991). These Executive Orders delegated authority to the U.S. Department of Transportation (DOT)[3] over transportation-related onshore facilities, deepwater ports, and vessels. A Memorandum of Understanding (MOU) between the Secretary of Transportation and the EPA Administrator, dated November 24, 1971 (36 FR 24080, December 18, 1971), defines non-transportation-related facilities and transportation-related facilities. A portion of this MOU is included as Appendix A to 40 CFR part 112. In addition, the U.S. Department of the Interior (DOI) regulates specific offshore facilities, including associated pipelines. The jurisdictional responsibilities of EPA, DOT, and DOI in relation to offshore facilities are further discussed in another Memorandum of Understanding, dated November 8, 1993. (This MOU is included as Appendix B to 40 CFR part 112.)

---

[2] The FRP rule applies to a subset of SPCC facilities, which are those that (1) have 42,000 gallons or more of oil storage capacity and transfer oil over water to or from vessels; or (2) have 1,000,000 gallons or more of oil storage capacity and lack secondary containment, are located at a distance such that a discharge from the facility could cause injury to fish and wildlife and sensitive environments or shut down a public water intake, *or* have experienced a reportable oil spill in an amount greater than or equal to 10,000 gallons within the last 5 years. See 40 CFR part 112.20.

[3] DOT delegated authority over transportation-related facilities and vessels to the U.S. Coast Guard (USCG).

FYI - Jurisdiction

EPA, USCG, DOT and DOI share responsibility for establishing spill prevention and response planning regulations under the Clean Water Act following the jurisdictional boundaries established in Executive Orders and MOUs.

However, EPA and USCG regulatory jurisdiction may differ from EPA and USCG response authority jurisdiction.

1.1.2 Statutory Framework

The Federal Water Pollution Control Act (FWPCA) of 1972, as amended, commonly known as the Clean Water Act (CWA), is the principal federal statute for protecting navigable waters, adjoining shorelines, and the waters of the contiguous zone from pollution.[4] Section 311 of the CWA addresses the control of oil and hazardous substance discharges, and provides the authority for promulgation of a regulation to prevent, prepare for, and respond to such discharges. Specifically, §311(j)(1)(C) mandates regulations establishing procedures, methods, equipment, and other requirements to prevent discharges of oil from vessels and facilities and to contain such discharges. (See *Appendix A* of this guidance for the text of CWA §311(j)(1)(C).)

§112.2

Oil means oil of any kind or in any form, including, but not limited to: fats, oils, or greases of animal, fish, or marine mammal origin; vegetable oils, including oils from seeds, nuts, fruits, or kernels; and, other oils and greases, including petroleum, fuel oil, sludge, synthetic oils, mineral oils, oil refuse, or oil mixed with wastes other than dredged spoil.

Note: The above text is an excerpt of the SPCC rule. Refer to 40 CFR part 112 for the full text of the rule.

Under CWA §311(a)(1), "oil" is defined to mean "oil of any kind or in any form..." In 1975, EPA published a notice on the applicability of the SPCC rule to non-petroleum oils. The notice affirmed that all facilities processing and storing non-petroleum oils (such as animal fats and vegetable oils or AFVOs) in the quantities and under the circumstances set out in 40 CFR part 112 are required to prepare and implement an SPCC Plan in accordance with that part (40 FR 28849, July 9, 1975). EPA stated that the broad and comprehensive definition of "oil" in the CWA is consistent with the expressed congressional intent to strengthen federal law for the prevention, control, and cleanup of oil spilled in the aquatic environment. Both EPA and the U.S. Coast Guard[5] have consistently interpreted and administered §311 as applicable to spills of non-petroleum-based oils, particularly because of the common physical and chemical properties of AFVOs and petroleum oils as well as their common potential for adverse environmental impact when discharged into water.

---

[4] FWPCA was enacted in 1948 and was amended on April 3, 1970 (Public Law 91-224) by the Water Quality Improvement Act (WQIA) of 1970. The WQIA amended the prohibitions on discharges of oil to allow such discharges only when consistent with regulations to be issued by the President and where permitted by Article IV of the 1954 International Convention for the Prevention of Pollution of the Sea by Oil (33 U.S.C. 1321). In issuing regulations, the President was authorized to determine quantities of oil which would be harmful to the public health or welfare of the U.S., including, but not limited to, fish, shellfish, and wildlife, as well as public and private property, shorelines and beaches.

[5] DOT delegated authority over transportation-related facilities and vessels to the U.S. Coast Guard. In March 2003, the Coast Guard formally transferred from the DOT to the Department of Homeland Security, but retains this CWA authority (Executive Order 13286, 68 FR 10619, March 5, 2003).

The Oil Pollution Act of 1990 (OPA) streamlined and strengthened EPA's ability to prepare for and respond to catastrophic oil discharges. Specifically, OPA expands prevention and preparedness activities, improves response capabilities, ensures that shippers and owners or operators of facilities that handle oil pay the costs associated with discharges that do occur, expands research and development programs, and establishes an Oil Spill Liability Trust Fund. OPA §4202(a)(6) amended CWA §311(j) to require promulgation of regulations to require owners or operators of certain vessels and facilities to prepare and submit Facility Response Plans (FRPs) for responding to a worst-case discharge of oil and to a substantial threat of such a discharge (CWA §311(j)(5)). EPA published the FRP rule on July 1, 1994, as an amendment to 40 CFR part 112. The FRP requirement for onshore facilities applies to any facility that, "because of its location, could reasonably be expected to cause substantial harm to the environment by discharging into or on the navigable waters, adjoining shorelines, or the exclusive economic zone."

OPA defined oil under §1001 differently than the CWA §311(a)(1) definition. Under OPA, "oil" means "oil of any kind or in any form, including petroleum, fuel oil, sludge, oil refuse, and oil mixed with wastes other than dredged spoil, but does not include any substance which is specifically listed or designated as a hazardous substance under subparagraphs (A) through (F) of section 101(14) of the Comprehensive Environmental Response, Compensation, and Liability Act (42 U.S.C. 9601) and which is subject to the provisions of that Act." The OPA definition did not amend the original CWA definition of oil and therefore was not incorporated into 40 CFR part 112.

While OPA did not result in revisions to the SPCC rule, OPA section 4113(a) required that the President conduct a study to determine whether liners or other secondary means of containment should be used to prevent leaking or aid in leak detection at onshore facilities used for the bulk storage of oil located near navigable waters. Executive Order 12777 tasked EPA with conducting this study.

The resulting study was completed in May 1996[6] and focused on the technical feasibility of using liners[7] and related systems to detect oil leaking from aboveground storage tanks (ASTs) and to prevent the leaking oil from contaminating soil and navigable waters. EPA assessed the technical feasibility of installing liners made from synthetic materials as well as earthen materials within secondary containment structures and under ASTs (i.e., undertank liners). EPA also assessed the feasibility of installing double bottoms on vertical ASTs as "other secondary means of containment," which could be used in place of undertank liners. The agency examined other technologies to aid in leak detection and looked at available data on liner costs. The study concluded that existing sources of information evaluated by EPA did indicate that a significant number of ASTs may be leaking or spilling oil. The study also showed that each of the different types of liners, such as impervious soil, coated or uncoated concrete, and geomembrane liners, can be effective in preventing groundwater contamination and in detecting leaks if properly installed and maintained. However, poor maintenance can significantly reduce the effectiveness of certain types of liners. The study resulted in EPA's recommendation to initiate a voluntary program to prevent leaks and spills, rather than a regulatory amendment. In the preamble to the 2002 SPCC rule

---

6 *EPA Liner Study: Report to Congress, Section 4113(a) of the Oil Pollution Act of 1990.* May 1996. OSWER 9380.0-24, EPA 540/R95/041, PB95-963538. See *Appendix H*.

7 For purposes of the study, EPA defined a liner as "an engineered system that makes secondary containment structures more impervious."

amendments, EPA clarified that it is not necessary for facility owner and operators to install liners in order to comply with the SPCC rule: "'effective containment' does not mean that liners are required for secondary containment areas. Liners are an option for meeting the secondary containment requirements, but are not required by the rule." (July 17, 2002, 67 FR 47102).

In 1995, Congress enacted the Edible Oil Regulatory Reform Act (EORRA). The statute mandates that most federal agencies[8] differentiate among and establish separate classes for various types of oils, specifically, animal fats and oils and greases, fish and marine mammal oils, oils of vegetable origin, and other oils and greases (including petroleum). In differentiating among these classes of oils, EORRA directed federal agencies to consider differences in these oils' physical, chemical, biological, and other properties, and in their environmental effects. On August 12, 1994, several agricultural organizations submitted to EPA a Petition for Reconsideration of the FRP rule as it applies to facilities that handle, store, or transport AFVOs.[9] On October 20, 1997, EPA denied the petition to amend the FRP rule (62 FR 54508) because it did not substantiate the petitioners' claims that AFVOs differ from petroleum oils in properties and effects. EPA concluded that the facts did not support a further differentiation between these groups of oils under the FRP rule. Instead, EPA found that a worst-case discharge or substantial threat of a discharge of AFVOs to navigable waters, adjoining shorelines, or the exclusive economic zone could reasonably be expected to cause substantial harm to the environment, including wildlife that may be killed by the discharge.

However, in amendments to the FRP rule on June 30, 2000, in response to EORRA requirements, EPA promulgated a separate approach for calculating planning volumes for a worst-case discharge in the FRPs for animal fat and vegetable oil facilities (65 FR 40776). EPA also published an advanced notice of proposed rulemaking requesting ideas from the public on how to differentiate among the SPCC requirements for facilities storing or using various categories of oil (64 FR 17227, April 8, 1999). In the 2002 revision of the SPCC rule, EPA established new subparts to facilitate differentiation among categories of oil listed in EORRA; however, the actual requirements in each of the subparts were identical. As discussed in *Section 1.3.3* of this chapter, EPA later removed and reserved certain sections that are not applicable to facilities that store or handle AFVOs. The 2008 SPCC rule amendments provided differentiated requirements for AFVOs in the form of revised integrity testing requirements at §112.12(c)(6) that are applicable to containers that meet specific criteria. *Chapter 7: Inspection, Evaluation, and Testing* discusses the differentiated integrity testing requirements for AFVO containers in detail.

1.2 Regulatory History

The SPCC rule was initially promulgated in 1973, with a few early revisions, and further modifications to the SPCC requirements were proposed for public comment on several occasions. EPA finalized many aspects of three proposals resulting in final revisions in the Federal Register (FR) in July 2002. In 2006, EPA amended the SPCC rule to streamline the requirements for a subset of facilities. In December 2008, EPA again amended the

---

8 The Food and Drug Administration and the Food Safety and Inspection Service are exempted from the requirements of EORRA.

9 "Petition for Reconsideration and Stay of Effective Date," August 12, 1994, submitted on behalf of the American Soybean Association, the Corn Refiners Association, the National Corn Growers Association, the Institute of Shortening & Edible Oils, the National Cotton Council, the National Cottonseed Products Association, and the National Oilseed Processors Association.

rule to provide increased clarity, to tailor requirements to particular industry sectors, and to streamline certain requirements. EPA promulgated revisions to the December 2008 amendments in November 2009 and finalized one additional amendment to the SPCC rule in April 2011. Throughout this time, EPA extended the compliance dates in the SPCC rule for amending and implementing existing SPCC Plans. EPA also extended the compliance dates for developing and implementing new Plans developed under 40 CFR part 112.

1.2.1 Initial Promulgation and Early Amendments

The SPCC rule was originally proposed in the *Federal Register* on July 19, 1973 (38 FR 19334). The final rule was published on December 11, 1973 and became effective on January 10, 1974 (38 FR 34164). The regulation established oil discharge prevention procedures, methods, and equipment requirements for non-transportation-related facilities with an aboveground (non-buried) oil storage capacity greater than 1,320 U.S. gallons (or greater than 660 U.S. gallons aboveground in a single tank) or a buried underground oil storage capacity greater than 42,000 U.S. gallons. Regulated facilities were also limited to those that, because of their location, could reasonably be expected to discharge oil into the navigable waters of the United States or adjoining shorelines. The rule included sections on general applicability, relevant definitions, and requirements for preparation of SPCC Plans; provisions for SPCC Plan amendments; civil penalty provisions; and requirements for the substance of the SPCC Plans.

Two early revisions were made to the original SPCC rule. On August 29, 1974, the regulation was amended (39 FR 31602) to set out EPA's policy on civil penalties for violation of the CWA §311 requirements. On March 26, 1976, the rule was again amended (41 FR 12657), primarily to clarify the criteria for determining whether or not a facility is subject to the regulation. Specifically, EPA clarified that manmade structures may not be used in the applicability determination relating to a facility's reasonable expectation of an oil discharge to navigable waters or adjoining shorelines when they restrain, hinder, contain or otherwise prevent a discharge to navigable waters or adjoining shorelines. This rulemaking also clarified that SPCC Plans must be in writing and specified procedures for mobile facilities to develop and implement Plans.[10]

On May 20, 1980 (45 FR 33814), amendments were proposed to reflect the changes in the jurisdiction of section 311 of the CWA that were brought about by the 1977 amendments to that Act. The notice also proposed amendments to the applicability criteria, requirements for new facilities, availability of SPCC Plans for review by EPA personnel, review of SPCC Plans by owners or operators, and other SPCC Plan requirements.

1.2.2 SPCC Task Force and GAO Recommendations

In January 1988, the shell plates of a reconstructed four-million gallon aboveground storage tank in Floreffe, Pennsylvania, experienced a brittle fracture failure. Brittle fracture is a type of structural failure in aboveground steel tanks, characterized by rapid crack formation that can cause sudden tank failure.[11] The tank split apart, collapsed, and discharged approximately 3.8 million U.S. gallons of diesel fuel. Of this amount, approximately 750,000 U.S. gallons were discharged into the Monongahela River. The spill temporarily

[10] Some examples of mobile facilities include onshore drilling or workover rigs, barge-mounted offshore drilling or workover rigs, and portable fueling facilities.

[11] For more information on brittle fracture evaluations see *Chapter 7: Inspection, Evaluation, and Testing*.

contaminated drinking water sources, damaged the ecosystems of the Monongahela and Ohio Rivers, and negatively affected private property and local businesses. Following the discharge, an SPCC Task Force was formed to examine federal regulations governing discharges from aboveground storage tanks. The Task Force, consisting of representatives from EPA headquarters and regions as well as other federal and state agencies, issued its findings and recommendations in May 1988. The findings focused on the prevention of catastrophic discharges and recommended changes to the SPCC program.[12] Specifically, the Task Force recommended that EPA establish additional technical requirements for SPCC Plan preparation and implementation, including:

- Adopting industry standards for new and relocated tanks;
- Differentiating SPCC requirements based on facility size;
- Modifying timeframes for SPCC Plan preparation, implementation, and review;
- Requiring strengthened integrity testing and periodic inspection of tanks and secondary containment;
- Requiring a more stringent attestation for a Professional Engineer to certify an SPCC Plan;
- Ensuring that employees undergo response training; and
- Modifying definitions and providing additional preamble discussion.

The Task Force also recommended that EPA expand the scope of the regulation to include requirements for facility-specific contingency planning and to specify countermeasures to be employed if a discharge should extend beyond the site in an uncontrolled manner. To better identify violations and enforce compliance, the Task Force recommended that EPA strengthen its facility inspection program. The Task Force also found that EPA did not have an adequate inventory of facilities subject to the regulation, and that improvements in national response coordination may be possible. Finally, the Task Force commented on the role of state and local resources and other federal agencies in oil discharge prevention and response efforts, and also recommended funding research on the development of oil discharge removal and control technology.

Figure 1-1: Aboveground storage tank in Floreffe, Pennsylvania.

In response to both the Monongahela River spill and an

[12] U.S. EPA, "The Oil Spill Prevention, Control, and Countermeasures Program Task Force Report," Interim Final Report, May 13, 1988) Available in EPA docket OPA-1991-0001.

oil spill that occurred at an oil refinery in Martinez, California in April 1988, the U.S. General Accounting Office (which is now referred to as the U.S. Government Accountability Office, or GAO) examined the adequacy of the federal regulations of aboveground oil storage tanks and the extent to which they addressed the unique problems of inland oil discharges. GAO's report, "Inland Oil Spills: Stronger Regulation and Enforcement Needed to Avoid Future Incidents," contained recommendations on regulations, inspections, enforcement, and government response that were similar to those of the SPCC Task Force (February 1989, GAO/RCED-89-65).[13] To amend the SPCC regulation, GAO recommended that EPA require:

- Aboveground oil storage tanks to be built and tested in accordance with industry and other specified standards;
- Facilities to plan how to react to a spill that overflows facility boundaries; and
- Stormwater drainage systems to be designed and operated to prevent oil from escaping through them. (Oil escaped through the drainage system during the oil spill in Martinez, California).

For inspections, GAO recommended that EPA (1) strengthen its aboveground oil storage facility inspection program by coordinating with state and local authorities, developing procedures for conducting and documenting inspections, defining and implementing minimum training procedures for inspectors, and establishing a national policy for fining violators; and (2) consider advantages and disadvantages of supplementing EPA inspection resources with state and local inspection resources, and require that facilities obtain certification from independent engineers indicating that facilities are in compliance with the regulations. Finally, the report included a recommendation to Congress that it amend the CWA to explicitly authorize the federal government to recover the costs of monitoring oil spill cleanups performed by private responsible parties, and suggested that it consider re-establishing the oil spill research and development program.

1.2.3 Proposed Revisions – 1991, 1993, and 1997

Following the Monongahela River and Martinez, California spills and recommendations of the SPCC Task Force and GAO, EPA proposed substantive revisions to the SPCC requirements on three occasions (1991, 1993, and 1997) and solicited public comment on these revisions. Specifically:

- On October 22, 1991 (56 FR 54612), EPA proposed changes in the applicability of the SPCC rule and in the required procedures for completing SPCC Plans, as well as the addition of a facility notification provision. The proposed rule also reflected changes in the jurisdiction of CWA §311 made by the 1977 and 1978 amendments to the Act.
- On February 17, 1993 (58 FR 8824), EPA published an additional proposed rule to incorporate new requirements added by OPA that directed facility owners and operators to prepare plans for responding to a worst-case discharge of oil and to a substantial threat of such a discharge (the FRP rule). EPA promulgated the FRP rule on July 1, 1994 (59 FR 34070). The 1993 proposed rule also included revisions to the SPCC requirements, including (1) a requirement for an SPCC

[13] Available at www.regulations.gov, docket ID: EPA-HQ-OPA-1991-0001-0042.

Plan to address training and methods of evaluating containers for protection against brittle fracture; (2) provisions for Regional Administrators to require amendments to an SPCC Plan and to require a Plan from an otherwise exempt facility when necessary to achieve the goals of the CWA; and (3) a requirement for Plan submission if an owner or operator invokes a waiver to certain technical requirements of the SPCC rule.

- On December 2, 1997 (62 FR 63812), EPA proposed further revisions to the SPCC rule in an effort to reduce the information collection burden without creating an adverse impact on public health or the environment. The proposed revisions were intended to give facility owners and operators flexibility to use alternative formats for SPCC Plans; to allow the use of certain records maintained pursuant to usual and customary business practices, or pursuant to the National Pollutant Discharge Elimination System (NPDES) program, in lieu of records mandated by the SPCC requirements; to reduce the information required to be submitted after certain discharges; and to extend the interval between SPCC Plan reviews by the facility owner/operator. At this time, EPA also proposed amendments to the FRP requirements, which were finalized on June 30, 2000 (65 FR 40776).

1.2.4 2002 Amendments

On July 17, 2002, EPA published a final rule amending the Oil Pollution Prevention regulation (67 FR 47042). The final rule became effective on August 16, 2002, and incorporated many of the proposed revisions from the 1991, 1993, and 1997 proposals. As a performance-based regulation, the amendments provided flexibility to the regulated community in meeting many of the oil discharge prevention requirements and the overall goal of preventing oil spills that may impact navigable waters or adjoining shorelines. In addition, the final rule included new subparts outlining the requirements for various classes of oil (pursuant to EORRA) , revised the applicability of the regulation, amended the requirements for completing SPCC Plans, and made other modifications. The final rule also contained a number of provisions designed to decrease regulatory burden on facility owners and operators subject to the rule. The specific amendments to the SPCC rule are discussed in more detail in *Section 1.3*, *Revised Rule Provisions*, below, as well as in *Appendix C* to this guidance, *Summary of Revised SPCC Rule Provisions*.

In response to the final SPCC amendments, several members of the regulated community filed legal challenges to certain aspects of the rule.[14] Settlement discussions between EPA and the plaintiffs led to an agreement on all issues except the definition of navigable waters. On May 25, 2004, EPA published a notice in the *Federal Register* (69 FR 29728) clarifying specific provisions of the SPCC rule to reflect settlement agreements. The *Federal Register* notice clarified statements regarding loading/unloading racks and impracticability that were challenged by the plaintiffs. In addition, EPA clarified aspects of a wastewater treatment exemption and specified which definition of “facility” applies when determining applicability of the FRP rule under §112.20(f)(1). EPA also announced the availability of a letter from EPA to the Petroleum

[14] See *American Petroleum Institute* v. *Leavitt* et al., No. 1;102CV02247 PLF and consolidated cases (D.D.C. filed November 14, 2002). Lead plaintiffs in the cases were the American Petroleum Institute, Marathon Oil Co., and the Petroleum Marketers Association of America.

Marketers Association of America (PMAA), which provided additional guidance on equivalent environmental protection with respect to requirements for integrity testing, security, and loading racks.[15]

1.2.5 Additional Amendments to Streamline the SPCC Rule

On September 20, 2004, EPA published two Notices of Data Availability (NODAs). The first NODA solicited comments on letters or other documents submitted to EPA that requested more focused or streamlined requirements for facilities subject to the SPCC rule that handle oil below a certain threshold amount, referred to as "certain facilities" (69 FR 56182). The second NODA solicited comments on whether alternate regulatory requirements would be appropriate for facilities with oil-filled and process equipment (69 FR 56184). In December 2005, based on the comments received on the NODAs as well as other information received, EPA proposed to amend the SPCC rule. The proposed amendments addressed a number of issues, including requirements pertaining to a subset of smaller facilities, oil-filled operational equipment meeting certain qualifying criteria, motive power containers, airport mobile refuelers, animal fats and vegetable oils, and the compliance date for farms (70 FR 73524, December 12, 2005). EPA finalized revisions in December 2006 (71 FR 77266, December 26, 2006). The 2006 final rule provided more streamlined, alternative approaches for compliance with oil spill prevention requirements for these entities. Its goal was to streamline the regulation in an effort to improve compliance, resulting in greater environmental protection.

The December 2006 SPCC rule amendments addressed only certain areas of the SPCC requirements and specific issues and concerns raised by the regulated community. The EPA Regulatory Agenda and the 2005 Office of Management and Budget (OMB) report on ''Regulatory Reform of the U.S. Manufacturing Sector'' highlighted other areas where further changes may be appropriate. Accordingly, in October 2007, EPA proposed additional amendments to the SPCC rule to address these changes (72 FR 58378, October 15, 2007).

EPA finalized these revisions in December 2008 (73 FR 74236, December 5, 2008), with modifications finalized in November 2009 (74 FR 58784, November 13, 2009); both of these actions became effective on January 14, 2010. Additionally, in response to legal challenges filed by members of the regulated community, EPA announced the vacatur of the July 2002 definition of "navigable waters", restoring the 1973 definition of "navigable waters" (73 FR 71941, November 26, 2008).

Finally, in April 2011, EPA published a final rule to exempt milk and milk product containers, associated piping and appurtenances from the SPCC regulation (76 FR 21652, April 18, 2011). The specific amendments to the SPCC rule are discussed in more detail in *Section 1.3: Revised Rule Provisions*, below, as well as in *Appendix C* to this guidance, *Summary of Revised SPCC Rule Provisions*.

1.2.6 Compliance Date Amendments

The compliance date is the date by which the owner or operator must have a Plan that complies with the revised rule requirements. On eight occasions following the 2002 final rule, EPA extended the compliance dates in §112.3 for facilities to update (or for new facilities to prepare) and implement an SPCC Plan that

[15] The *Federal Register* notice and letter to PMAA are available on the EPA Web site, at http://www.epa.gov/emergencies/lawsregs.htm#froppr and http://www.epa.gov/emergencies/content/spcc/spccref.htm#letter, respectively.

complies with the revised requirements. All of these extensions alleviated the need for individual extension requests from owners and operators:

- On January 9, 2003 (68 FR 1348), EPA extended the compliance date by 60 days to allow time to consider comments on a proposed one-year extension that was published concurrently in the Federal Register.

- On April 17, 2003 (68 FR 18890), EPA extended the compliance dates by one year, to provide sufficient time for the regulated community to undertake the actions necessary to update (or prepare) their plans in accordance with the 2002 amendments.

- On August 11, 2004 (69 FR 48794), EPA extended the compliance dates by an additional 18 months, to provide members of the regulated community with sufficient time to understand clarifications related to a partial settlement of litigation involving the July 2002 amendments, and to be able to incorporate these clarifications, as appropriate, in preparing and updating their SPCC Plans.

- On February 17, 2006 (71 FR 8462), EPA extended the compliance dates to allow the agency time to take final action on the proposed amendments to the SPCC requirements before owners and operators were required to prepare, amend, and implement their SPCC Plans (to allow owners and operators to take advantage of any modifications that would be provided by a final SPCC amendment rule); to allow the regulated community the opportunity to understand the material presented in this guidance; and to provide time for facilities that might have difficulty meeting the compliance dates because they were adversely affected by recent hurricanes.

  Additionally, the 2006 SPCC rule amendments (71 FR 77266, December 26, 2006) specifically extended the compliance dates for the owner or operator of a farm to prepare or amend and implement the farm's SPCC Plan until the effective date of a rule addressing whether to provide differentiated requirements for farms.

  In this notice, EPA eliminated the six-month interim period in §112.3(a) between the compliance dates for Plan amendment and implementation.

- On May 16, 2007 (72 FR 27443), EPA extended the compliance dates to allow the agency time to promulgate further revisions to the SPCC rule before owners and operators are required to prepare or amend, and implement their SPCC Plans.

- On June 19, 2009 (74 FR 29136), EPA extended the compliance dates to provide the owner or operator of a facility the opportunity to fully understand all of the regulatory amendments offered by revisions to the SPCC rule promulgated since July 2002 and to provide sufficient time for the agency to review comments on the December 2008 amendments and to promulgate any additional revisions that result from this review.

These compliance date amendments established the same compliance date for farms as for all other SPCC-regulated facilities.

- On October 14, 2010 (75 FR 63093), EPA extended the compliance date an additional year to allow owners and operators sufficient time to amend and implement their SPCC Plans. The extension applied to all facilities, except for oil drilling, production or workover facilities that are offshore or that have an offshore component and onshore facilities required to have and submit FRPs. The compliance date for these offshore facilities and FRP-subject facilities remained November 10, 2010.

- On October 18, 2011 (76 FR 72120), EPA published a direct final rule that extended the compliance date by an additional 18 months for the owners or operators of farms, who because of their unique nature, were disproportionately affected by severe weather conditions in the continental United States. The extension allowed additional time for owners and operators of farms to prepare and implement SPCC Plans. The agency confirmed the compliance date extension in a final rule published November 22, 2011 (76 FR 72120).

It should be noted that all compliance dates are in the past. If the owner or operator of a facility did not comply with the SPCC rule and does not have an SPCC Plan, the owner or operator must develop a Plan immediately in accordance with the amendments to the rule from 2002 forward.

The current compliance dates under §112.3(a) and (b) apply to all SPCC-regulated facilities, as follows:

A farm, starting operation...	Must...
On or before August 16, 2002	Maintain its existing SPCC Plan Amend and implement the amended SPCC Plan no later than May 10, 2013
After August 16, 2002 through May 10, 2013	Prepare and implement an SPCC Plan no later than May 10, 2013
After May 10, 2013	Prepare and implement an SPCC Plan *before* beginning operations

An oil drilling, production or workover facility, including a mobile or portable facility, located offshore or with an offshore component; or an onshore facility that is required to have and submit FRPs starting operation...	Must...
On or before August 16, 2002	Maintain its existing SPCC Plan Amend and implement the amended SPCC Plan no later than November 10, 2010
After August 16, 2002 through November 10, 2010	Prepare and implement an SPCC Plan no later than November 10, 2010
After November 10, 2010 (excluding oil production facilities)	Prepare and implement an SPCC Plan before beginning operations
After November 10, 2010 (oil production facilities)	Prepare and implement an SPCC Plan within six months after beginning operations.

The December 2008 rule amendments (73 FR 74236, December 5, 2008) allow new oil production facilities a period of six months after the start of operations to prepare and implement an SPCC Plan. A "new" oil production facility is one that becomes operational after the applicable compliance date, not an existing oil production facility (in operation prior to the compliance date) that has changed name, owner, operator, or equipment.

All other facilities starting operation...	Must...
On or before August 16, 2002	Maintain its existing SPCC Plan Amend and implement the amended SPCC Plan no later than November 10, 2011
After August 16, 2002 through November 10, 2011	Prepare and implement an SPCC Plan no later than November 10, 2011
After November 10, 2011 (excluding oil production facilities)	Prepare and implement an SPCC Plan before beginning operations
After November 10, 2011 (oil production facilities)	Prepare and implement an SPCC Plan within six months after beginning operations.

The compliance date amendments described above affected only requirements of the rule amendments (67 FR 47042, July 17, 2002; 71 FR 77266, December 26, 2006; 73 FR 74236, December 5, 2008; and 74 FR 58784, November 13, 2009) that imposed new or more stringent compliance obligations than did the original 1973 SPCC rule. Provisions in these amendments that provide regulatory relief were not affected by these compliance date amendments because they would not typically require amendments to existing Plans ''to ensure compliance'' (see §112.3). Provisions in these amendments that provide regulatory relief to facilities were applicable as of the effective date of the amendment.

Furthermore, where certain dates appear as part of the rule text in provisions other than §112.3, as listed below, these dates are not affected by, or replaced by, the compliance date:

- §112.5(b) requires the owner/operator to complete a review and evaluation of the SPCC Plan at least once every five years from the date the facility becomes subject to this part; or, if your facility was in operation on or before August 16, 2002, five years from the date your last review was required under this part.
- §§112.8(d)(1) and 112.12(d)(1) require that buried piping that is installed or replaced on or after August 16, 2002 have protective wrapping and coating and cathodic protection, or otherwise satisfy the corrosion protection provisions for piping in 40 CFR part 280 or a State program approved under 40 CFR part 281.
- §§112.8(c)(4) and 112.12(c)(4) require the owner/operator to protect any completely buried metallic storage tank installed on or after January 10, 1974 from corrosion by coatings or cathodic protection, and regularly leak test such tanks.

1.3 Revised Rule Provisions

The 2002 revision to the SPCC rule clarified the language and organization of the regulation, made technical changes, and reduced regulatory burden in certain areas of the rule. The 2006 final rule amended the SPCC rule to streamline the requirements for a subset of facilities. The 2008 final rule amended the SPCC rule to provide increased clarity with respect to specific regulatory requirements, tailor requirements to particular industry sectors, and streamline certain rule requirements. Finally, the 2009 amendments removed certain provisions that were finalized in 2008, and provided minor technical corrections, as discussed in more detail below. This section provides an overview of the current rule's organization and highlights some of the more substantive changes made to the rule in 2002 through 2009.

For the inspector's reference, *Appendix B* of this guidance includes the Oil Pollution Prevention regulation, 40 CFR part 112, in its entirety and current as of the publication of this guidance. Since the regulation is subject to change, the appendix is provided for informational purposes only. The *Federal Register* – the official daily publication for rules, proposed rules, and notices of federal agencies and organizations – is available electronically from the U.S. Government Printing Office Web site at http://www.gpoaccess.gov/fr/. General and permanent rules published in the *Federal Register* are codified in the *Code of Federal Regulations* (CFR), available electronically at http://www.gpoaccess.gov/cfr/. Each volume of the CFR is updated once each calendar year and is issued on a quarterly basis. For a more frequently updated version of the CFR, refer to the *Electronic Code of Federal Regulations (e-CFR)* at http://www.gpoaccess.gov/ecfr/. The e-CFR is updated daily but is not an official legal edition of the CFR. Inspectors implementing the SPCC program should always consult the aforementioned resources (or their equivalent) to obtain the current version of the SPCC rule.

1.3.1 Rule Organization

The Oil Pollution Prevention regulation at 40 CFR part 112 is divided into four subparts. Subparts A, B, and C address oil discharge prevention requirements and are commonly referred to as the "SPCC rule." Subpart D, commonly referred to as the "FRP rule," addresses facility response planning requirements in the event of an oil discharge, and includes the FRP requirements and facility response training and drill requirements.

The regulation is organized as follows:

Subpart A	Applicability, definitions, and general requirements for all facilities and all types of oils
Subpart B	Requirements for petroleum oils and non-petroleum oils, except those covered in Subpart C
Subpart C	Requirements for animal fats and oils and greases, and fish and marine mammal oils; and for vegetable oils, including oils from seeds, nuts, fruits, and kernels
Subpart D	Response requirements

Pertaining to all oil and facility types, subpart A contains the following key sections of the SPCC rule:

§112.1	General Applicability
§112.2	Definitions
§112.3	Requirement to Prepare and Implement an SPCC Plan
§112.4	Amendment of an SPCC Plan by Regional Administrator
§112.5	Amendment of an SPCC Plan by Owners or Operators
§112.6	Qualified Facilities
§112.7	General Requirements for SPCC Plans

Additional requirements for specific facility types are given in §§112.8 through 112.12,[16] and are found within subparts B and C. These facility types and their corresponding sections of the rule are as follows:

[16] The 2002 SPCC rule included requirements within subpart C that are not applicable or are inappropriate for animal fats and vegetable oils (§§112.13 through 112.15). These sections were promulgated because EPA had not proposed differentiated SPCC requirements for public notice and comment, and were removed and reserved by rulemaking on December 26, 2006 (71 FR 77266).

§112.8	Onshore Facilities (excluding oil production facilities)
§112.9	Oil Production Facilities (onshore)
§112.10	Oil Drilling and Workover Facilities (onshore)
§112.11	Oil Drilling, Production, or Workover Facilities (offshore)
§112.12	Onshore Facilities (requirements for AFVOs)

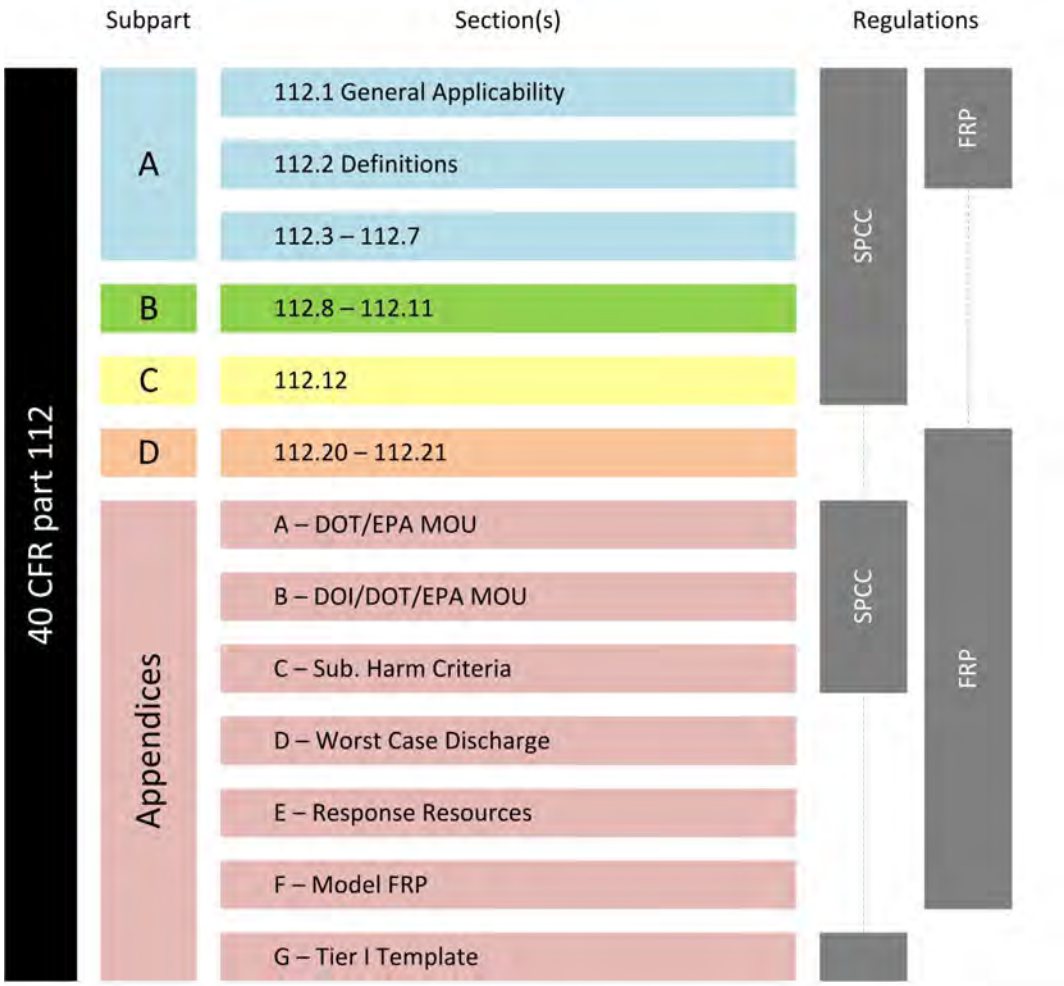
The Oil Pollution Prevention regulation also contains several appendices, including Memoranda of Understanding, information referenced in the FRP rule (Substantial Harm Criteria, Determination of a Worst Case Discharge Planning Volume, Determination and Evaluation of Required Response Resources for Facility Response Plans, and a model Facility-Specific Response Plan) and an SPCC Plan template for certain qualified facilities.

Appendix C to part 112 - Substantial Harm Criteria provides guidance for determining FRP applicability. However, in accordance with Section 3.0 of Appendix C, an SPCC-regulated facility owner/operator must complete and maintain a copy of Attachment C-II "*Certification of the Applicability of the Substantial Harm Criteria"* at the facility when the facility[17] does not meet the substantial harm criteria listed in Attachment C-I "*Flowchart of Criteria for Substantial Harm*." Copies of Attachment C-I and C-II are included in Appendix C of 40 CFR 112 and in *Appendix H* of this Guidance.

Figure 1-2 illustrates the organization of 40 CFR part 112, highlighting sections that pertain to the SPCC and FRP requirements. Note that all FRP-regulated facilities are also subject to the SPCC requirements and must develop and implement an SPCC Plan.

[17] Many facility owner/operators include a copy of Attachment C-II "*Certification of the Applicability of the Substantial Harm Criteria* as an appendix to the SPCC Plan.

Figure 1-2: Graphical representation of 40 CFR part 112 sections.



Note that Section 3.0 of Appendix C requires an SPCC-regulated facility owner/operator to complete and maintain a copy of Attachment C-II at the facility when the facility does not meet the substantial harm criteria outlined in Attachment C-I of the appendix.

1.3.2 Summary of Major 2002 Revisions

The 2002 amendments shifted the SPCC rule to a more performance-based regulation that allows owners, operators, and the certifying Professional Engineer (PE) flexibility in meeting many of the prevention requirements. The "environmental equivalence" provision, in particular, allows facilities to deviate from specified substantive requirements of the SPCC rule (except secondary containment provisions and certain administrative provisions) by implementing alternate measures, certified by a PE, that provide equivalent environmental protection. Deviations are not allowed for the administrative provisions of the rule, §§112.1 through 112.5, and for certain additional requirements in §112.7, such as recordkeeping and training.

Additionally, in situations where secondary containment is not practicable, the owner/operator must (1) clearly explain the reason for the determination in the SPCC Plan; (2) for bulk storage containers, conduct periodic integrity testing of containers and associated valves and piping; and (3) prepare an oil spill contingency plan and a written commitment of manpower, equipment, and materials to expeditiously control and remove any quantity of oil discharged that may be harmful (§112.7(d)).

The 2002 rule amendments also revised many other rule provisions, both to provide regulatory relief and to make technical changes. Specifically, the amendments exempted many completely buried underground storage tanks (USTs), containers that store less than 55 U.S. gallons, and certain wastewater treatment operations/facilities. The amendments also increased the oil capacity threshold for the applicability of the rule, and both reduced information required after a discharge and raised the regulatory trigger for its submission. In addition, the rule amendments decreased the frequency of Plan review from every three years to every five years.

Technical amendments to the rule include requiring brittle fracture evaluation for field-constructed aboveground containers; strengthening the integrity testing requirements; finalizing additional general requirements for spill planning, preparedness, and reporting; adding a requirement for a facility diagram; clarifying the rule's applicability to the operational use of oil; and making the PE certification and associated attestation more specific. Also, the rule allows alternative formats for SPCC Plans with a cross-reference and mandates specific time frames for employee training.

The specific amendments to each section of the SPCC rule finalized in 2002 are highlighted in *Appendix C* of this guidance, *Summary of Revised SPCC Rule Provisions*.

1.3.3 Summary of 2006 Revisions

In 2006, EPA amended the SPCC rule to streamline the regulatory requirements for a subset of facilities. The revisions specifically addressed certain "qualified facilities," oil-filled operational equipment, motive power, s, animal fats and vegetable oils, and farms. Each of these topics is discussed below. The specific amendments to each section of the SPCC rule finalized in 2006 are also highlighted in *Appendix C* of this guidance, *Summary of Revised SPCC Rule Provisions*.

Qualified Facilities

The 2006 amendments provided an option to allow the owner or operator of a facility that meets qualifying criteria (a "qualified facility") to self-certify the facility's SPCC Plan in lieu of review and certification by a licensed Professional Engineer (PE). The 2008 amendments further streamlined and tailored SPCC rule requirements for a subset of qualified facilities (see *Section 1.3.4*). While this section briefly describes the associated regulatory requirements, separate guidance is available for qualified facilities at http://www.epa.gov/oem/content/spcc/spcc_qf.htm.

To be eligible to take advantage of the qualified facility self-certification option, a facility must meet the following criteria:

1. In the three years before the SPCC Plan is certified, (or since becoming subject to the SPCC rule if the facility has been in operation for less than three years), the facility has had no discharges to navigable waters or adjoining shorelines as described below:
   - A single discharge greater than 1,000 U.S. gallons, or
   - Two discharges as each greater than 42 U.S. gallons within any 12-month period; and
2. The facility has an aggregate aboveground oil storage capacity of 10,000 U.S. gallons or less.

Facilities that meet these criteria were later designated as Tier II qualified facilities in the 2008 amendments (see *Section 1.3.4*). Discharges to navigable waters or adjoining shorelines (i.e., discharges as described in §112.1(b)) that are the result of natural disasters, acts of war, or terrorism do not disqualify a facility from using the self-certification option. When determining spill history, the U.S. gallon amount specified in the criterion (either 1,000 or 42) refers to the amount of oil that actually reaches navigable waters or adjoining shorelines and not the total amount of oil spilled. The entire volume of the discharge is considered to be oil for the purpose of these reporting requirements.

Self-certified Tier II qualified facility Plans can include alternative methods that provide environmental equivalence when each alternate method has been reviewed and certified in writing by a PE[18] (§112.6(d)). Because the flexibility offered by the use of environmental equivalence (discussed in detail in *Chapter 3: Environmental Equivalence*) is not available for Plans without review and certification by a PE, the 2006 rule provided streamlined requirements for security requirements and bulk storage container inspections. Similarly, self-certified Tier II Plans may include a determination that secondary containment is impracticable and use alternative provisions in lieu of secondary containment, when the determination and alternative provisions are reviewed and certified in writing by a PE.

The self-certification is optional for qualified facilities. The owner or operator of an otherwise-qualified facility may choose to prepare a Plan in accordance with the general Plan requirements (§112.7) and applicable requirements in subparts B and C, and have the Plan certified by a PE as required under §112.3(d) rather than self-certify the SPCC Plan.

Oil-Filled Operational Equipment

The 2006 final rule amended §112.7 to provide an alternative option for facilities with qualified oil-filled operational equipment. Oil-filled operational equipment includes equipment with an oil storage container (or multiple containers) in which the oil is present solely to support the function of the apparatus or the device.

[18] A self-certified Plan with PE-certified portions is called a "hybrid Plan."

"Qualified" oil-filled operational equipment are those that have had no discharges to navigable waters or adjoining shorelines in the three years prior to the SPCC Plan certification date (or since the facility became subject to 40 CFR part 112 if it has been in operation for less than three years), as described below:[19]

- A single discharge greater than 1,000 U.S. gallons, or
- Two discharges as each greater than 42 U.S. gallons within any 12-month period;

In lieu of general secondary containment for qualified oil-filled operational equipment, facility owners or operators may establish and document the facility procedures for inspections or a monitoring program to detect equipment failure and/or a discharge, develop an oil spill contingency plan, and provide a written commitment of manpower, equipment, and materials required to expeditiously control and remove any quantity of oil discharged that may be harmful.

If an owner/operator submitted an FRP to EPA in accordance with the requirements in §§112.20 and 112.21, the owner/operator does not need to develop an oil spill contingency plan and provide a written commitment of resources. Facilities do not have to make an impracticability determination for each piece of qualified oil-filled operational equipment. *Chapter 2: SPCC Rule Applicability* provides more detail on the definition of oil-filled operational equipment (see *Section 2.10.4*) and *Chapter 4: Secondary Containment and Impracticability* (see *Section 4.2.1*) describes the alternative requirements for qualified oil-filled operational equipment.

Motive Power

The 2006 amendments exempted motive power containers from the SPCC rule. Motive power containers are onboard bulk storage containers used primarily to power the movement of a motor vehicle, or ancillary onboard oil-filled operational equipment. The provision was included under the general applicability section, §112.1(d). This exemption of motive power containers is discussed in more detail in *Chapter 2: SPCC Rule Applicability* (see *Section 2.8.6*).

Mobile Refuelers

The 2006 amendments exempted mobile refuelers from the requirements of §§112.8(c)(2) and (11) and 112.12(c)(2) and (11). EPA defines a mobile refueler as "a bulk storage container, onboard a vehicle or towed, that is designed or used solely to store and transport fuel for transfer into or from an aircraft, motor vehicle, locomotive, vessel, ground service equipment, or other oil storage container." Mobile refuelers are discussed in more detail in *Chapter 2: SPCC Rule Applicability* (see *Section 2.5.1*) and *Chapter 4: Secondary Containment and Impracticability* (see *Section 4.7.6*). Additionally, in the 2008 amendments, this exemption from sized secondary containment requirements was expanded to include similar tanker trucks not storing a fuel, as explained below in *Section 1.3.4* in the paragraph titled "*General Secondary Containment for Non-Transportation-Related Tank Trucks*."

[19] Unlike the qualified facility criteria there is no capacity criterion for oil-filled operational equipment.

Animal Fats and Vegetable Oils (AFVOs)

The 2006 rule removed and reserved three sections of Subpart C of the regulation because they were not appropriate for animal fats and vegetable oils (AVFOs). These sections included requirements for onshore oil production facilities (§112.13), requirements for onshore oil drilling and workover facilities (§112.14), and requirements for offshore oil drilling, production, or workover facilities (§112.15). This change has generated a common misconception that AFVOs are no longer regulated under the SPCC requirements. This is incorrect; AFVOs continue to be regulated under the SPCC rule and have specific requirements in §112.12.

Farms

A farm is defined as a facility on a tract of land devoted to the production of crops or raising of animals, including fish, which produced and sold, or normally would have produced and sold, $1,000 or more of agricultural products during a year (§112.2). In 2006, EPA extended the compliance date for farms until the agency promulgated a rule specifically addressing how farms should be regulated under the SPCC rule. The 2006 compliance date extension was superseded by the 2009 rule that established November 10, 2010 as the compliance date for farms (74 FR 29136, June 19, 2009). The compliance date was later extended to May 10, 2013 due to severe weather conditions in the continental United States that had a disproportionate effect on the agricultural sector (76 FR 64245, October 18, 2011).

1.3.4 Summary of 2008 Revisions

On December 5, 2008, EPA amended the SPCC rule to address a number of issues and concerns raised by the regulated community. The amendments were intended to increase clarity, streamline the requirements to which facility owners and operators must adhere, and modify the requirements for specific industry sectors, including farms and oil production facilities. Specific topics addressed by the 2008 rule revisions are discussed below, and are also highlighted in *Appendix C* of this guidance, *Summary of Revised SPCC Rule Provisions*.

Hot-mix Asphalt (HMA)

The 2008 amendments exempted hot-mix asphalt (HMA) and HMA-containers from the rule requirements by modifying §112.1(d)(2) and adding paragraph §112.1(d)(8). HMA is typically asphalt cement (AC) mixed with aggregate. The capacity of HMA containers is not counted toward the facility's oil storage capacity calculation because this material is unlikely to flow as a result of the entrained aggregate. Therefore, there would be very few circumstances, if any, in which a discharge of HMA would have the potential to reach navigable waters or adjoining shorelines. However, AC, asphalt emulsions, and cutbacks, that are not entrained with aggregates and are thus not HMAs, continue to be subject to SPCC regulation. This exemption is discussed further in *Chapter 2: SPCC Rule Applicability* (see *Section 2.2.4*).

Pesticide Application Equipment

The 2008 amendments exempted all pesticide application equipment and related mix containers regardless of ownership or where used when crop oil or adjuvant oil is added to the pesticide formulation (§112.1(d)(10)). EPA also modified §112.1(d)(2) so that the capacity of pesticide application equipment and

related mix containers is not counted toward the facility's oil storage capacity calculation. This exemption is discussed further in *Chapter 2: SPCC Rule Applicability* (see *Section 2.8.9*).

Residential Heating Oil Containers

The 2008 rule amended §112.1(d) and added paragraph §112.1(d)(9) to exempt from SPCC applicability containers (both aboveground and completely buried) that are used to store oil for the sole purpose of heating single-family residences (including at a farm). Furthermore, the capacity of such containers does not count toward the facility aggregate oil storage capacity. This exemption is discussed further in *Chapter 2: SPCC Rule Applicability* (see *Section 2.8.8*).

Definition of Facility

The 2008 amendments modified the definition of the term "facility" under §112.2 and clarified that this definition alone governs the applicability of 40 CFR part 112. The amendments also clarified that the owner or operator has the discretion to identify which contiguous or non-contiguous buildings, properties, parcels, leases, structures, installations, pipes or pipelines make up the facility. The amendments also clarified that a facility owner/operator may determine that s/he is no longer subject to the SPCC requirements. However, the revisions note that owners and operators may not characterize a facility so as to simply avoid applicability of the rule. This amendment is discussed in more detail in *Chapter 2: SPCC Rule Applicability* (see *Section 2.4*).

Facility Diagram

The 2008 final rule amended §112.7(a)(3) to clarify that the facility diagram must include all fixed containers (that is, those that are not mobile or portable). For any mobile or portable containers (such as drums or totes), a facility owner or operator must mark the storage area on the facility diagram for these containers. The owner or operator may mark the number of containers, contents, and capacity of each container either on the facility diagram or in a separate description in the SPCC Plan. Also, the amendment requires that certain intra-facility piping (i.e., gathering lines) exempted from the SPCC requirements in the December 2008 action be identified on the facility diagram and marked as "exempt." This amendment is discussed in more detail in *Chapter 6: Facility Diagram and Description* (See *Sections 6.4.5, 6.4.6* and *6.4.8*).

Loading/Unloading Racks

The 2008 final rule defined the term "loading/unloading rack", which governs whether a facility's oil transfer equipment and areas are subject to §112.7(h). Under §112.2, loading/unloading rack means "a fixed structure (such as a platform, gangway) necessary for loading or unloading a tank truck or tank car, which is located at a facility subject to the requirements of this part. A loading/unloading rack includes a loading or unloading arm and may include any combination of the following: piping assemblages, valves, pumps, shut-off devices, overfill sensors, or personnel safety devices." This definition and amendment is discussed in more detail in *Chapter 4: Secondary Containment and Impracticability* (see *Section 4.7.3*).

The 2008 amendments excluded oil production facilities and farms from the loading/unloading rack requirements at §112.7(h); however, this provision was removed in the 2009 final rule.

Qualified Facilities

The 2008 amendments designated a subset of qualified facilities (Tier I qualified facilities) as those that meet the current qualified facility eligibility criteria and that have no oil storage containers with an individual aboveground storage capacity greater than 5,000 U.S. gallons. Under §112.6, the owner or operator of a Tier I qualified facility has the option to complete and implement a self-certified SPCC Plan template (found in Appendix G to 40 CFR part 112) in lieu of a full SPCC Plan to comply with the SPCC regulation. The template is comprised of a set of streamlined SPCC rule requirements. The rule designated all other qualified facilities as Tier II qualified facilities.

General Secondary Containment Requirements

The 2008 amendments modified the general secondary containment requirements under §112.7(c) by clarifying that the scope of the general secondary containment requirements takes into consideration the typical failure mode and most likely quantity of oil that would be discharged. The amendment clarified that general secondary containment requirements allow for use of both active and passive secondary containment measures and provided additional examples of prevention systems for onshore facilities. This amendment is discussed in more detail in *Chapter 4: Secondary Containment and Impracticability* (see *Section 4.2*).

General Secondary Containment for Non-Transportation-Related Tank Trucks

The 2008 amendments extend the 2006 exemption from sized secondary containment requirements provided to mobile refuelers to non-transportation-related tank trucks at facilities subject to the SPCC rule (§§112.6(a)(3)(ii), 112.8(c)(2), 112.8(c)(11), 112.12(c)(2), and 112.12(c)(11)). The general secondary containment requirements in §112.7(c) apply to non-transportation-related tank trucks. This amendment is discussed in more detail in *Chapter 4: Secondary Containment and Impracticability* (see *Section 4.7.6*).

Facility Security Requirements

The 2008 rule amended the facility security requirements at §112.7(g) to be performance-based and allow an owner or operator of a facility to tailor its security measures to suit the facility's characteristics and location. The facility owner or operator is required to document in the SPCC Plan how these security measures are implemented. This amendment is discussed in more detail in *Chapter 3: Environmental Equivalence* (see *Section 3.3.6*).

Bulk Storage Container Integrity Testing Requirements

The 2008 final rule amended the requirements at §§112.8(c)(6) and 112.12(c)(6) to provide flexibility in complying with the bulk storage container integrity testing requirements. The amendment allows an owner or operator to consult and rely on industry standards to determine the appropriate qualifications for tank inspectors/testing personnel, and the type and frequency of integrity testing required for a particular container size, configuration, and design. These requirements are discussed in more detail in *Chapter 7: Inspection, Evaluation, and Testing*.

Integrity Testing Requirements for Animals Fats and Vegetable Oils

The 2008 SPCC rule amendments differentiate the integrity testing requirements at §112.12(c)(6) for an owner or operator of a facility that handles Animal Fats and Vegetable Oils (AFVOs). Under this amendment, the PE or the owner or operator self-certifying an SPCC Plan is provided the flexibility to use a visual inspection program for integrity testing for containers that store AFVOs and that meet certain criteria identified in §112.12(c)(6)(ii). This requirement is discussed in more detail in *Chapter 7: Inspection, Evaluation, and Testing* (see *Section 7.2.4*).

Oil Production Facilities

The 2008 amendments tailored several requirements for oil production facilities which are discussed in more detail in *Chapter 2: SPCC Rule Applicability* and *Chapter 4: Secondary Containment and Impracticability*, including:

- Amending the definition of "production facility" in §112.2 to be consistent with the amendments to the definition of "facility" (see *Section 2.4.3*);
- Providing new oil production facilities with additional time to prepare and implement their SPCC Plans;
- Providing an alternative option for flow-through process vessels (such as separators and heater-treaters) at oil production facilities to comply with the general secondary containment requirement and additional oil spill prevention measures in lieu of sized secondary containment (see *Section 4.8.1*);
- Exempting certain intra-facility gathering lines (see *Section 2.8.10*);
- Providing a compliance alternative for produced water containers to comply with the general secondary containment requirement and additional oil spill prevention measures in lieu of sized secondary containment (see *Section 4.8.2*);
- Establishing a minimum set of requirements for flowline and intra-facility gathering line maintenance programs and providing a compliance alternative to secondary containment for this piping (see *Sections 3.3.5* and *4.2.2*); and
- Clarifying the definition of ''permanently closed'' as it applies to oil production facilities and containers present at an oil production facility (see *Section 2.8.1*).

The 2008 amendments also included several provisions that were removed from the rule in 2009, including an exclusion for oil production facilities from the loading/unloading rack requirements at §112.7(h); an exemption for certain produced water containers; and alternative qualified facilities eligibility criteria for oil production facilities to be eligible to self-certify SPCC Plans.

Man-made Structures

The 2008 amendments to the SPCC rule clarified that manmade features such as drainage control structures and dikes cannot be used to conclude that there is no reasonable expectation that a discharge from a facility will reach navigable waters or adjoining shorelines (§112.1(d)(1)(i)). However, it may be appropriate for a facility owner or operator to consider man-made structures (for example, dikes, equipment, buildings, basements or other containment structures) to determine how to comply with the SPCC rule secondary containment and integrity testing requirements. This provision is addressed further in *Chapter 4: Secondary Containment and Impracticability* (see *Section 4.4.4*).

Wind Turbines

The 2008 amendments clarified that wind turbines meet the definition of oil-filled operational equipment adopted in the December 2006 rule amendments. Therefore, the alternative compliance option for qualified oil-filled operational equipment in §112.7(k) may be available for SPCC-regulated wind turbines that meet the qualifying criteria for oil-filled operational equipment.

Underground Emergency Diesel Generator Tanks at Nuclear Power Stations

The 2008 amendments exempted underground oil storage tanks deferred from regulation under 40 CFR part 280, as originally promulgated, that supply emergency diesel generators at nuclear power generation facilities licensed by Nuclear Regulatory Commission (NRC) and that meet the NRC design criteria and quality assurance criteria. This exemption, under §§112.1(d)(2)(i) and 112.1(d)(4), includes both tanks that are completely buried and certain tanks that are below-grade and vaulted. This exemption is discussed further in *Chapter 2: SPCC Rule Applicability* (see *Section 2.8.4*).

1.3.5 Summary of Navigable Waters Ruling

On November 26, 2008 (73 FR 71941), the Federal Register published EPA's direct final rule to amend a CWA section 311 regulation that defines the term "navigable waters." In this action, EPA announced the vacatur of the July 17, 2002, revisions to the definition of "navigable waters" in accordance with an order, issued by the United States District Court for the District of Columbia (D.D.C.) in American Petroleum Institute v. Johnson, 571 F.Supp.2d 165 (D.D.C. 2008), invalidating those revisions. The court decision also restored the regulatory definition of "navigable waters" promulgated by EPA in 1973; consequently, EPA amended the definition of "navigable waters" in part 112 to comply with that decision (see *Section 2.6.4*).

1.3.6 Summary of the 2009 Amendments to the 2008 Rule

On November 13, 2009, EPA promulgated revisions to the December 2008 amendments (74 FR 58784). In this action, EPA removed the following provisions from the SPCC rule: the exclusion of farms and oil production facilities from the loading/unloading rack requirements under §112.7(h), the exemption of certain produced water containers at oil production facilities, and the alternative qualified facilities eligibility criteria for oil production facilities. These amendments also retained or provided minor technical corrections to the December 2008 provisions.

1.3.7 Effective Date of the 2008 and 2009 Amendments

EPA twice delayed the effective date of the 2008 amendments. The effective date for the 2008 amendments was originally scheduled for February 3, 2009. However, on February 3, 2009 (74 FR 5900), the effective date was delayed by 60 days, until April 4, 2009, in accordance with the January 20, 2009, White House memorandum entitled ''Regulatory Review'' (74 FR 4435, January 26, 2009) and the memorandum from the Office of Management and Budget entitled ''Implementation of Memorandum Concerning Regulatory Review'' (M–09–08, January 21, 2009). EPA took that action to ensure that the final rule reflected proper consideration of all relevant facts. In the February 3, 2009 notice, EPA requested public comment on the extension of the effective date and its duration, and on the regulatory amendments contained in the final rule. As a result of public comment, EPA further delayed the April 4, 2009 effective date until January 14, 2010 to allow sufficient time to properly address public comments. These public comments were addressed in the November 2009 final amendments to the SPCC rule (74 FR 58784, November 13, 2009), which also became effective on January 14, 2010. Modifications to the effective date did not affect the compliance date for preparing or updating an SPCC Plan.

FYI – Effective date and compliance date

The *effective date* is the date that amendments in the rule document affect the current Code of Federal Regulations (CFR). The current CFR consists of the rules published in the latest CFR volume and any effective amendments published in the *Federal Register* since the revision date of the latest CFR volume. The effective date is not the same as the rule's compliance date.

The *compliance date* is the date that the affected person (that is, the owner or operator) must comply with the revised rule requirements.

1.3.8 Summary of the Milk and Milk Product Container Exemption

On January 15, 2009, the agency published a proposal to exempt from SPCC requirements milk containers and associated piping and appurtenances provided they are constructed according to current applicable 3–A Sanitary Standards, and are subject to the current applicable Grade ''A'' Pasteurized Milk Ordinance (PMO) or a State dairy regulatory requirement equivalent to the current applicable PMO (74 FR 2463).

EPA modified the proposed rule language and exempted milk and milk product containers, associated piping and appurtenances on April 18, 2011 (76 FR 21652). EPA believes that the combination of these specific construction and sanitation standards address the prevention of oil discharges in quantities that may be harmful.

The capacity of the exempt milk and milk product containers, piping and appurtenances is excluded from the calculation of a facility's total oil storage capacity when determining if the facility is subject to the SPCC rule. This exemption is addressed further in *Chapter 2: SPCC Rule Applicability* (see *Section 2.8.11*).

1.4 Using This Guidance

SPCC Guidance for Regional Inspectors is intended to assist regional EPA inspectors in implementing the revised SPCC rule, including environmental equivalence, impracticability, and integrity testing, as well as the role of the inspector in the review of these provisions. It is also intended to establish a nationally consistent understanding among regional EPA inspectors on how certain provisions of the rule may be applied. Finally, the guidance also provides the regulated community, including PEs and qualified facility owner/operators, with information that is valuable for the development and implementation of SPCC Plans. This guidance does not address all aspects of the SPCC rule, nor is it a substitute for the regulation itself. Additional guidance is available for qualified facility owners/operators at http://www.epa.gov/oem/content/spcc/spcc_qf.htm.

Excerpts of the SPCC rule relevant to a particular section of this guidance are provided in text boxes. This information is provided for informational purposes only. The reader should always refer to the full text of the current 40 CFR part 112 rule for the applicable regulatory language, available from the Government Printing Office Web site at http://www.gpoaccess.gov/fr/.

Many of the terms used in this guidance have specific regulatory definitions in 40 CFR 112.2; however, other regulatory programs may define some of these terms differently. Please refer to §112.2 of the rule and associated preamble of the July 2002, December 2006, December 2008, and November 2009 *Federal Register* publications for clarification of defined terms in the SPCC rule. An acronyms list, provided at the beginning of this document, defines all acronyms used throughout the guidance.

This guidance is divided into seven main chapters and includes several appendices for the reader's reference, as follows:

- ***Chapter 1: Introduction*** discusses the purpose and scope of 40 CFR part 112, the regulatory history, and the 2002, 2006, 2008, 2009, and 2011 rule amendments.
- ***Chapter 2: SPCC Rule Applicability*** clarifies the facilities, activities, and equipment that are subject to the SPCC rule through an in-depth discussion of the rule and relevant scenarios.
- ***Chapter 3: Environmental Equivalence*** discusses the use of the "environmental equivalence" provision, which allows facilities to implement alternate measures based on site-specific considerations, as long as the measures provide equivalent environmental protection, in accordance with good engineering practice and as determined by a PE.
- ***Chapter 4: Secondary Containment and Impracticability*** discusses the secondary containment requirements and explains when an impracticability determination can be made and how the determination should be documented.
- ***Chapter 5: Oil/Water Separators*** addresses various scenarios involving oil/water separators with respect to the SPCC rule requirements.
- ***Chapter 6: Facility Diagram and Description*** provides guidelines on the necessary level of detail for facility diagrams included in SPCC Plans. This section also includes example facility diagrams for different types of facilities.

- ***Chapter 7: Inspection, Evaluation, and Testing*** explains the inspection, evaluation, and testing requirements for facilities subject to the SPCC rule, as well as how "environmental equivalence" may apply for the integrity testing requirements of the SPCC rule.

The appendices include a complete copy of the relevant sections of the statutory authority from the Clean Water Act; the Oil Pollution Prevention regulation (40 CFR part 112); the Discharge of Oil regulation (40 CFR part 110); the Criteria for State, Local and Regional Oil Removal Contingency Plans (40 CFR part 109); a summary of revised rule provisions; model SPCC Plans; a model contingency plan; inspector checklists; and a collection of other SPCC policy documents.

Chapter 2 SPCC Rule Applicability

2.1 Introduction

The SPCC rule establishes requirements to prepare and implement SPCC Plans. SPCC Plans complement existing laws, regulations, rules, standards, policies, and procedures pertaining to safety, fire prevention, and oil pollution prevention. The purpose of an SPCC Plan is to form a comprehensive oil spill prevention program that minimizes the potential for discharges. The SPCC Plan must address all relevant spill prevention, control, and countermeasures necessary at the specific facility.

The rule applies to the owners and operators of non-transportation-related onshore and offshore facilities that could reasonably be expected to discharge oil into navigable waters of the United States or adjoining shorelines in quantities that may be harmful. This chapter clarifies which facilities, activities, and equipment are subject to the SPCC rule. The facility owner/operator is responsible for determining whether the facility is subject to the SPCC rule, however, this determination is subject to review by the Regional Administrator or his delegated representative.

§112.1(b)

...this part applies to any owner or operator of a non-transportation-related onshore or offshore facility engaged in drilling, producing, gathering, storing, processing, refining, transferring, distributing, using, or consuming oil and oil products, which due to its location, could reasonably be expected to discharge oil in quantities that may be harmful, as described in part 110 of this chapter, into or upon the navigable waters of the United States or adjoining shorelines...

Note: The above text is an excerpt of the SPCC rule. Refer to 40 CFR part 112 for the full text of the rule.

2.1.1 Summary of General Applicability

Section 112.1 establishes the general applicability of the SPCC rule. The SPCC rule applies to facilities that:

- Are non-transportation-related;
- Have an aboveground oil storage capacity of more than 1,320 U.S. gallons or a completely buried oil storage capacity greater than 42,000 U.S; and
- Could reasonably be expected to discharge oil to navigable waters or adjoining shorelines in quantities that may be harmful.

Facilities that are owned and operated by federal, state, local government or tribal entities are equally subject to the regulation[20] as any other facility (although the federal government is not subject to civil penalties). Unlike some other federal environmental programs, the Clean Water Act does not authorize EPA to delegate the SPCC program implementation or enforcement to State, local, or tribal representatives.

[20] The SPCC rule requires an owner or operator to develop an SPCC Plan. Under the CWA the definition of owner or operator includes “person” which includes federal, state and local government or tribal entities (33 USC 1362(4) (CWA Section 502(4))).

Applicability

Specifically, EPA exempts:

- Any facility where the completely buried oil storage capacity is 42,000 U.S. gallons or less and the aggregate aboveground oil storage capacity is 1,320 U.S. gallons or less;
- Completely buried oil tanks and associated piping and equipment that are subject to all of the technical requirements under 40 CFR part 280 or 281;
- Underground oil storage tanks, including below-grade vaulted tanks that supply emergency diesel generators at a nuclear power generation facility licensed by the Nuclear Regulatory Commission (NRC) and subject to any NRC provision regarding design and quality criteria, including but not limited to 10 CFR part 50;
- Permanently closed oil containers;
- Any container with an oil storage capacity less than 55 U.S. gallons;
- Any facility or part thereof used exclusively for wastewater treatment;
- Motive power oil containers;
- Hot-mix asphalt or any hot-mix asphalt container;
- Containers storing heating oil used solely at a single-family residence;
- Pesticide application equipment or related mix containers (with adjuvant oil);
- Intra-facility oil gathering lines subject to the regulatory requirements of 49 CFR part 192 or 195; and
- Any milk and milk product container and associated piping and appurtenance.

Do not include exempt oil containers or oil equipment when calculating the total oil storage capacity of the facility. (see §112.1(d))

Section 112.1(d) describes facilities subject to EPA jurisdiction (i.e., that are non-transportation-related) and the activities and equipment that are exempt from the SPCC rule and from the facility total oil storage capacity calculations. The section also describes the types of facilities that are outside EPA jurisdiction and therefore not subject to the SPCC rule. Notwithstanding the exemptions provided in §112.1(d), under §112.1(f) the Regional Administrator has discretion to require the owner or operator of any facility, subject to EPA's jurisdiction under §311(j) of the Clean Water Act (CWA), to prepare and implement an SPCC Plan, or part of an SPCC Plan.

This chapter further explains each of the applicability criteria listed in §112.1 and provides examples of how these criteria are applied. The remainder of this chapter is organized as follows:

- ***Section 2.2*** discusses the definition of "oil" and the regulated activities.
- ***Section 2.3*** discusses activities involving oil.
- ***Section 2.4*** explains what a "facility" is and provides examples of how a facility can be determined.

- ***Section 2.5*** discusses the difference between "transportation-related" and "non-transportation-related" facilities in determining jurisdiction of regulatory agencies.
- ***Section 2.6*** discusses the criteria for a facility to have a "reasonable expectation of a discharge to navigable waters in quantities that may be harmful."
- ***Section 2.7*** addresses storage capacity thresholds and methods of calculating storage capacity.
- ***Section 2.8*** addresses the exemptions to the SPCC rule.
- ***Section 2.9*** discusses the process for a Regional Administrator to determine applicability, outside of the exemptions listed in §112.1(d).
- ***Section 2.10*** addresses the applicability of the rule requirements to different kinds of containers.
- ***Section 2.11*** discusses the applicability of Facility Response Plan (FRP) requirements.
- ***Section 2.12*** describes the role of the EPA inspector.

2.2 Definition of Oil

The SPCC rule applies to the owners and operators of facilities with the potential to discharge oil in quantities that may be harmful to navigable waters or adjoining shorelines. The SPCC rule's definition of oil derives from §311(a)(1) of the Clean Water Act (CWA) which defines oil as *"oil of any kind or in any form, including, but not limited to, petroleum, fuel oil, sludge, oil refuse, and oil mixed with wastes other than dredged spoil."*

§112.2

Oil means oil of any kind or in any form, including, but not limited to: fats, oils, or greases of animal, fish, or marine mammal origin; vegetable oils, including oils from seeds, nuts, fruits, or kernels; and, other oils and greases, including petroleum, fuel oil, sludge, synthetic oils, mineral oils, oil refuse, or oil mixed with wastes other than dredged spoil.

Note: The above text is an excerpt of the SPCC rule. Refer to 40 CFR part 112 for the full text of the rule.

OPA §1001 defined oil separately to exclude any substance which is specifically listed or designated as a hazardous substance under Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA) and which is subject to provisions of that Act.[21] Although oil is defined separately under OPA, that definition did not amend the original CWA definition of oil in §311(a)(1) and therefore was not incorporated into the definition of oil under 40 CFR part 112.2 that applies to both SPCC and FRP regulatory requirements.

[21] Under OPA, "oil" means "oil of any kind or in any form, including petroleum, fuel oil, sludge, oil refuse, and oil mixed with wastes other than dredged spoil, but does not include any substance which is specifically listed or designated as a hazardous substance under subparagraphs (A) through (F) of section 101(14) of the Comprehensive Environmental Response, Compensation, and Liability Act (42 U.S.C. 9601) and which is subject to the provisions of that Act."

In response to Edible Oil Regulatory Reform Act (EORRA) of 1995 (33 U.S.C. 2720) requirements, the oil definition under §112.2 was revised to include the categories of oil in EORRA. Those categories are: (1) petroleum oils, (2) animal fats and vegetable oils; and, (3) other non-petroleum oils and greases.[22]

Section 112.2 of the SPCC rule defines oil as "oil of any kind or in any form, including, but not limited to: fats, oils, or greases of animal, fish, or marine mammal origin; vegetable oils, including oils from seeds, nuts, fruits, or kernels; and, other oils and greases, including petroleum, fuel oil, sludge, synthetic oils, mineral oils, oil refuse, or oil mixed with wastes other than dredged spoil."

The U.S. Coast Guard (USCG) maintains a separate list of substances it considers oil for its regulatory purposes. The list is available on the USCG Web site and may be used as a guide when determining if a particular substance is an oil.[23] However, it is important to note that for purposes of EPA's regulations, the USCG list is not comprehensive and does not include all oils that are subject to 40 CFR part 112. The sections below discuss whether or not specific substances are considered oils for purposes of SPCC regulation.

2.2.1 Petroleum Oils and Non-Petroleum Oils

The SPCC rule applies to both petroleum oils and non-petroleum oils. Petroleum oils include, but are not limited to, crude and refined petroleum products, asphalt, gasoline, fuel oils, mineral oils, naphtha, sludge, oil refuse, and oil mixed with wastes other than dredged spoil. Nonpetroleum oils and greases include coal tar, creosote, silicon fluids, pine oil, turpentine, and tall oils. (67 FR 47075, July 17, 2002).

Subpart B of 40 CFR part 112 covers both "petroleum oils and non-petroleum oils..." Petroleum oils and non-petroleum oils, including synthetic oils, share common physical properties and produce similar environmental effects. Petroleum and non-petroleum oils can enter all parts of an aquatic system and adjacent shoreline, and similar methods of containment, removal and cleanup are used to reduce the harm created by spills of both types of oils.

2.2.2 Synthetic Oils

Synthetic oils are used in a wide range of applications, including as heat transfer fluids, engine fluids, hydraulic and transmission fluids, metalworking fluids, dielectric fluids, compressor lubricants, and turbine lubricants. Synthetic oils are created by chemical synthesis rather than by refining petroleum crude or extracting oil from plant seeds. Oils that are derived from plant material may be considered animal fats and vegetable oils under subpart C of 40 CFR part 112.

---

22 EPA provided notice in 1975 that affirmed that animal fats and vegetable oils (AFVOs) were subject to the SPCC rule (40 FR 28849, July 9, 1975). For more information see *Chapter 1: Introduction*.

23 See the "List of Petroleum and Non-Petroleum Oils" on the USCG Web site at http://www.uscg.mil/vrp/faq/oil.shtml under "Additional References."

2.2.3 Animal Fats and Vegetable Oils (AFVO)

Animal fats and vegetable oils are covered under the SPCC regulation. Animal fats include but are not limited to fats, oils, and greases of animal origin (for example, lard and tallow), fish (for example, cod liver oil), or marine mammal origin (for example, whale oil).

Vegetable oils include but are not limited to oils of vegetable origin, including oils from seeds, nuts, fruits, and kernels. Examples of vegetable oils include: corn oil, rapeseed oil, coconut oil, palm oil, soy bean oil, sunflower seed oil, cottonseed oil, and peanut oil. (67 FR 47075, July 17, 2002).

§112.2

Animal fat means a non-petroleum oil, fat, or grease of animal, fish, or marine mammal origin.

Vegetable oil means a non-petroleum oil or fat of vegetable origin, including but not limited to oils and fats derived from plant seeds, nuts, fruits, and kernels.

Note: The above text is an excerpt of the SPCC rule. Refer to 40 CFR part 112 for the full text of the rule.

2.2.4 Asphalt

Asphalt is a thermoplastic material, composed of unsaturated aliphatic and aromatic compounds, that softens when heated and hardens upon cooling. Within a certain temperature range, it exhibits viscoelastic properties with viscous flow behavior and elastic deformation. All types of asphalt are petroleum oil products, and its composition depends on the source of the crude oil and the process used to manufacture it.

The SPCC rule applies to asphalt cement (AC), as well as to asphalt derivatives such as cutbacks and emulsions. Because of the operational conditions under which AC, cutbacks and emulsions are used and stored, they do pose a risk of being discharged into navigable waters or adjoining shorelines. Although AC) is semi-solid or solid at ambient temperature and pressure, it is generally stored at elevated temperatures. Hot AC is liquid—similar to other semi-solid oils, such as paraffin wax and heavy bunker fuels—and therefore is capable of flowing. Cutbacks and emulsions are liquid at ambient temperature, and because of their low viscosity, they may flow when discharged onto the ground. All of these oils are regulated under the SPCC rule to prevent discharges to navigable waters or adjoining shorelines.

However, hot-mix asphalt (HMA) and HMA containers are exempt from the SPCC rule. HMA is a blend of AC and aggregate material, such as stone, ground tires, sand, or gravel, which is formed into final paving products for use on roads and parking lots. HMA is unlikely to flow as a result of the entrained aggregate, such that there would be very few circumstances, if any, in which a discharge of HMA would have the potential to reach navigable waters or adjoining shorelines.

2.2.5 Natural Gas and Condensate

The SPCC rule does not apply to natural gas (including liquid natural gas and liquid petroleum gas). EPA does not consider highly volatile liquids that volatilize on contact with air or water, such as liquid natural gas or liquid petroleum gas, to be oil (67 FR 47076, July 17, 2002). Furthermore, EPA has stated that hydrocarbons in a

gaseous phase under ambient pressure and temperature, such as natural gas, present at SPCC regulated facilities are not regulated under the SPCC rule (73 FR 74271, December 5, 2008).

However, natural gas liquid condensate (often referred to as "natural gasoline" or "drip gas") is an oil subject to the SPCC rule. Condensate can accumulate in tanks, containers, or other equipment. For the purposes of determining SPCC applicability, containers with 55 gallons or more in capacity storing condensate must be included in a natural gas facility's total oil storage capacity calculation.

More information on specific types of facilities handling both natural gas and oil and how they are regulated under the SPCC rule can be found in *Section 2.4.7*.

2.2.6 Oil and Water Mixtures

Oil and water mixture containers are subject to the SPCC rule. A mixture of wastewater and oil is ''oil'' under the statutory and regulatory definition of the term (33 U.S.C. 1321(a)(1) and 40 CFR 110.2 and 112.2). A discharge of wastewater containing oil to navigable waters or adjoining shorelines in a ''harmful quantity'' (40 CFR part 110) is prohibited (see July 17, 2002, 67 FR 47069). One example of an oil and water mixture is produced water.

2.2.7 Produced Water

The SPCC rule applies to produced water from an oil well. Produced water is the oil and water mixture resulting from the separation of crude oil or gas from the fluids or gases extracted from the oil/gas reservoir, prior to disposal, subsequent use (e.g., re-injection or beneficial reuse), or further treatment. Produced water's chemical and physical characteristics vary considerably depending on the geologic formation, usually being commingled with oil and gas at the wellhead, and changing in composition as the oil or natural gas fraction is separated and sent to market.

§112.2

Produced water container means a storage container at an oil production facility used to store the produced water after initial oil/water separation, and prior to reinjection, beneficial reuse, discharge, or transfer for disposal.

Note: The above text is an excerpt of the SPCC rule. Refer to 40 CFR part 112 for the full text of the rule.

Produced water is typically collected in produced water containers at the end of the oil and gas treatment process, and often accumulates emulsified oil not captured in the separation process. Under normal operating conditions, a layer of oil may be present on top of the fluids. The amount of oil by volume observed in produced water storage containers varies, but based on EPA's assessment, is generally estimated to range from less than one to ten percent by volume, and can be greater. Oil may be present not only in free phase, but also in other forms, such as in a dissolved phase, emulsion or a sludge at the bottom of the produced water container.

Oil discharges to navigable waters or adjoining shorelines from an oil/water mixture in a produced water container may cause harm. Such mixtures[24] are regulated as oil under the SPCC rule. Therefore, the capacity of

[24] Refers to mixtures in the produced water container.

produced water containers counts toward the facility aggregate oil storage capacity. Produced water containers at oil production, oil recycling or oil recovery facilities are not eligible for the wastewater treatment exemption in §112.1(d)(6).

2.2.8 Hazardous Substances and Hazardous Waste

The definition of "oil" in §112.2 includes but is not limited to "oil mixed with wastes other than dredged spoil." Oils covered under the SPCC rule include certain hazardous substances or hazardous wastes that are oils, as well as certain hazardous substances or hazardous wastes that are mixed with oils. Containers storing these substances may also be covered by other regulations, such as the Resource Conservation and Recovery Act (RCRA) or CERCLA (also known as Superfund). For example, the definition of oil under §112.2 includes "used oil" because it is an oil mixed with wastes. "Used oil," as defined in EPA's *Standards for the Management of Used Oil* at 40 CFR 279.1, means any oil that has been refined from crude oil, or any synthetic oil, that has been used and as a result of such use is contaminated by physical or chemical impurities.

Inspectors should evaluate whether containers storing hazardous substances or mixtures of wastes contain oil. Hazardous substances or hazardous wastes that are neither oils nor mixed with oils are not subject to SPCC rule requirements. For purposes of 40 CFR part 112, the CWA §311(b)(2) hazardous substances as identified under 40 CFR part 116 are not considered oils. However, an oil mixture that includes a CWA hazardous substance is subject to 40 CFR part 112 when it meets the definition of oil in the regulation. For example, benzene is a CWA hazardous substance and therefore does not meet the definition of oil in §112.2; however, benzene is a constituent of gasoline which is a mixture that includes other oils. Gasoline is an oil as defined under 40 CFR part 112.2.

Although the rule contains an exemption for completely buried tanks that are subject to all underground storage tank (UST) technical requirements of 40 CFR part 280 and/or a state program approved under part 281 under §112.1(d)(2)(i) or (4), tanks containing RCRA hazardous wastes are not subject to the UST rules. Therefore, when RCRA hazardous wastes tanks located at a facility subject to the SPCC rule also contain oil, they are subject to the SPCC rule requirements.

2.2.9 Denatured Ethanol used in Renewable Fuels

Renewable fuels, such as E85 or "flex fuel" (15% unleaded gasoline and 85% ethanol) are produced in a blending process.[25] Ethanol used for fuel often contains a denaturing additive (typically gasoline, natural gasoline, diesel fuel or other oil petroleum product) which is oil. Therefore, the final denatured ethanol is also considered an oil, and facilities handling or storing denatured ethanol may be subject to the SPCC requirements. An EPA letter dated November 7, 2006 details the Agency's position on denatured ethanol (see *Appendix H*).

[25] For more information on ethanol renewable fuels see: http://epa.gov/region07/priorities/agriculture/pdf/ethanol_plants_manual.pdf

2.2.10 Biodiesel and Biodiesel Blends

Biodiesel and biodiesel blends are other types of renewable fuels that are often stored and handled at facilities regulated under 40 CFR part 112.[26] Biodiesel, designated B100, is a domestic, renewable fuel for diesel engines derived from natural oils like soybean oil. Biodiesel is comprised of mono-alkyl esters of long chain fatty acids derived from vegetable oils or animal fats.

Biodiesel can be used in any concentration with petroleum-based diesel fuel in existing diesel engines with little or no modification. Biodiesel is not the same as raw vegetable oil. It is produced by a chemical process which removes the glycerin from the oil. Biodiesel is typically produced by a reaction of a vegetable oil or animal fat with an alcohol such as methanol or ethanol in the presence of a catalyst to yield mono-alkyl esters and glycerin, which is removed.

Biodiesel blends are a blend of biodiesel fuel with petroleum-based diesel fuel, designated BXX, where XX represents the volume percentage of biodiesel fuel in the blend. Both biodiesel (B100) and biodiesel blends are considered oil for the purposes of 40 CFR part 112.

2.3 Activities Involving Oil

Section 112.1(b) specifies the following oil-related activities are regulated under the SPCC rule: "drilling, producing, gathering, storing, processing, refining, transferring, distributing, using, or consuming oil and oil products." These activities are subject to SPCC provided the facility meets the other applicability criteria in §112.1. *Table 2-1* provides examples of these activities.

§112.1(b)

...this part applies to any owner or operator of a non-transportation-related onshore or offshore facility engaged in ***drilling, producing, gathering, storing, processing, refining, transferring, distributing, using, or consuming*** oil and oil products....

Note: The above text is an excerpt of the SPCC rule. Refer to 40 CFR part 112 for the full text of the rule. ***Emphasis added***.

[26] For more information on biodiesel renewable fuels see: http://epa.gov/region07/priorities/agriculture/pdf/biodiesel_manual.pdf

Table 2-1: Examples of some oil-related activities that may be regulated under 40 CFR part 112.[27]

Activity	Examples of Oil-related Regulated Activities
Drilling	Drilling a well to extract crude oil or natural gas and associated products (such as wet natural gas) from a subsurface field
Producing	Extracting product from a well and separating the crude oil and/or gas from other associated products (e.g., water, sediment)
Gathering	Collecting oil from numerous wells, tank batteries, or platforms and transporting it to a main storage facility, processing plant, or shipping point
Storing	Storing oil in containers prior to use, while being used, or prior to further distribution in commerce
Processing	Treating oil using a series of processes to prepare the oil for commercial use, consumption, further refining, manufacturing, or distribution
Refining	Separating crude oil into different types of hydrocarbons through distillation, cracking, reforming, and other processes; separating animal fats and vegetable oils from free fatty acids and other impurities
Transferring	Transferring oil between containers, such as between a railcar or tank truck and a bulk storage container, or between stock tanks and manufacturing equipment
Distributing	Selling or marketing oil for further commerce or moving oil using equipment such as highway vehicles, railroad cars, or pipeline systems in the confines of a non-transportation-related facility. Note that businesses commonly referred to as oil distributors and retailers are also "storing" oil, as described above
Using	Using oil for mechanical or operational purposes in a manner that does not significantly reduce the quantity of oil, such as using oil to lubricate moving parts, provide insulation, or for other purposes in electrical equipment, electrical transformers, and hydraulic equipment
Consuming	Consuming oil in a manner that reduces the amount of oil, such as burning as fuel in a generator

2.4 Facilities

2.4.1 Definition of Facility

The definition of "facility" governs the overall applicability of 40 CFR part 112, and thus is used to determine the scope of a facility's boundaries in order to determine if the facility is subject to the SPCC and/or FRP requirements. The boundary or extent of a "facility" depends on site-specific circumstances. Factors that may be considered relevant in delineating the boundaries of a facility under 40 CFR 112 may include, but are not limited to:

- Ownership, management, and operation of the buildings, structures, equipment, installations, pipes, or pipelines on the site;
- Similarity in functions, operational characteristics, and types of activities occurring at the site;

[27] The examples listed in this table are not exhaustive and are for illustrative purposes only.

- Adjacency; or
- Shared drainage pathways (e.g., same receiving water bodies).

The facility owner or operator, or a Professional Engineer (PE) on behalf of the facility owner/operator, must make a judgment of what constitutes the "facility." Once the owner or operator determines the facility boundaries for purposes of the SPCC rule, then the same boundaries apply for FRP applicability. Note that generally, an SPCC-regulated facility excludes components that are not subject to EPA's jurisdiction, but are instead subject solely to the jurisdiction of other agencies, such as the Department of Transportation (DOT) or the United States Coast Guard (USCG).

§112.2

Facility means any mobile or fixed, onshore or offshore building, property, parcel, lease, structure, installation, equipment, pipe, or pipeline (other than a vessel or a public vessel) used in oil well drilling operations, oil production, oil refining, oil storage, oil gathering, oil processing, oil transfer, oil distribution, and oil waste treatment, or in which oil is used, as described in appendix A to this part. The boundaries of a facility depend on several site-specific factors, including but not limited to, the ownership or operation of buildings, structures, and equipment on the same site and types of activity at the site. Contiguous or non-contiguous buildings, properties, parcels, leases, structures, installations, pipes, or pipelines under the ownership or operation of the same person may be considered separate facilities. Only this definition governs whether a facility is subject to this part.

Note: The above text is an excerpt of the SPCC rule. Refer to 40 CFR part 112 for the full text of the rule.

Contiguous or non-contiguous buildings, properties, parcels, leases, structures, installations, pipes, or pipelines under the ownership or operation of the same person may be considered separate facilities for SPCC purposes. For example, a single facility may be composed of various oil-containing areas spread over a relatively large campus, such as multiple operational areas within a military base. Each operational area may be considered a separate facility. The military base may not necessarily include single-family homes occupied by military personnel as part of the facility if these are considered personal space similar to civilian single-family residences. However, larger military barracks for which a branch of the military controls, operates, and maintains the space would be included as part of a facility.

While the facility owner/operator has some discretion in defining the parameters of the facility, the boundaries of a facility may not be drawn to solely avoid regulation under 40 CFR part 112. For example, two contiguous operational areas, each with 700 gallons in aboveground storage capacity, that have the same owner, perform similar functions, are attended by the same personnel, and are in other ways indistinguishable from each other, would reasonably be expected to represent a single facility under the SPCC rule, and would therefore be required to have an SPCC Plan, since the capacity of this facility is above the 1,320-gallon aboveground threshold. These two operational areas would not be defined as two separate facilities under the definition of "facility" in §112.2. EPA reserves the right to make its own facility boundary determination after reviewing the Plan or inspecting the facility.

The facility owner and operator is responsible for ensuring that an SPCC Plan is prepared. A single site may have multiple owners and/or operators, and therefore may be divided into multiple facilities. Factors to

consider in determining which owner or operator should prepare the Plan include who has control over day-to-day operations of the facility or particular containers and equipment, who trains the employee(s) involved in oil handling activities, who will conduct the required inspections and tests, and who will be responsible for responding to and cleaning up any discharge of oil. EPA expects that the owners and operators will cooperate to prepare one or more Plans, as appropriate, to be kept at each facility when attended more than four hours per day.

SPCC facilities include not only permanent facilities with fixed storage and equipment, but also those that have only standby, temporary, and seasonal storage as described under §112.1(b)(3), as well as construction facilities. The owners and operators of mobile facilities (addressed in §112.3(a)) can create a general Plan, instead of developing a new Plan each time the facility is moved to a new location. Types of operations (mobile facilities) using a mobile plan include, but are not limited to, mobile fueling operations, road construction projects, drilling operations, and workover operations.

Because the physical surroundings of mobile facilities are subject to change, §112.3(a)(2) of the SPCC rule indicates that the owner or operator of a mobile facility may have a ''general'' Plan and need not prepare a new Plan each time the mobile facility is moved to a new site. When a mobile facility is moved, it must be located and installed using the spill prevention practices outlined in its Plan. In accordance with §112.3(a)(2), the Plan is only required to be implemented ''while the facility is in a fixed (non-transportation) operating mode'' (67 FR 47081, July 17, 2002).

2.4.2 Definitions of Onshore and Offshore Facility

EPA was delegated the authority to regulate non-transportation-related onshore and offshore facilities that could reasonably be expected to discharge oil into navigable waters of the United States or adjoining shorelines. Section 112.2 defines an "onshore facility" as "any facility of any kind located in, on, or under any land within the United States, other than submerged lands." Requirements under Subparts B and C are divided based on the location of the facility and the type of operations. Sections 112.8 and 112.12 apply to all onshore facilities (excluding oil production facilities). Section 112.9 applies to all onshore oil production facilities and §112.10 applies to all onshore oil drilling and workover facilities.

"Offshore facility" means any facility of any kind (other than a vessel or public vessel) located in, on, or under any of the navigable waters of the United States, and any facility of any kind that is subject to the jurisdiction of the United States and is located in, on, or under any other waters. Section 112.11 applies to all offshore oil drilling, production, or workover facilities.

§112.2

Onshore facility means any facility of any kind located in, on, or under any land within the United States, other than submerged lands.

Offshore facility means any facility of any kind (other than a vessel or public vessel) located in, on, or under any of the navigable waters of the United States, and any facility of any kind that is subject to the jurisdiction of the United States and is located in, on, or under any other waters.

Note: The above text is an excerpt of the SPCC rule. Refer to 40 CFR part 112 for the full text of the rule.

Some facilities may be comprised of both onshore and offshore components. In these instances, facilities may be considered "hybrid" facilities and subject to more than one set of requirements under either Subpart B or C of the rule. For example, an oil production facility located along a coastline that has a tank battery located onshore and associated wellheads and flowlines that are located offshore may be subject to the requirements of §112.9 (for onshore oil production facilities) and §112.11 (for offshore oil drilling, workover and production facilities).

2.4.3 Definition of Production Facility

A "production facility" is a type of "facility" as defined in §112.2. A "production facility" includes all the structures (including but not limited to wells, platforms, or storage facilities), piping (including but not limited to flowlines or intra-facility gathering lines), or equipment (including but not limited to workover equipment, separation equipment, or auxiliary non-transportation-related equipment) used in the production, extraction, recovery, lifting, stabilization, separation or treatment of oil (including condensate) and associated storage or measurement and is located in an oil or gas field, at a facility.

§112.2

Production facility means all structures (including but not limited to wells, platforms, or storage facilities), piping (including but not limited to flowlines or intra-facility gathering lines), or equipment (including but not limited to workover equipment, separation equipment, or auxiliary non-transportation-related equipment) used in the production, extraction, recovery, lifting, stabilization, separation or treating of oil (including condensate) and associated storage or measurement and is located in an oil or gas field, at a facility. This definition governs whether such structures, piping, or equipment are subject to a specific section of this part.

Note: The above text is an excerpt of the SPCC rule. Refer to 40 CFR part 112 for the full text of the rule.

The definition of "production facility" in §112.2 is narrower than the definition of facility and is used to determine which sections of the rule may apply at a particular facility. This definition governs whether such structures, piping, or equipment are subject to §112.9 of the rule. That is, if a facility meets the definition of a production facility, the owner or operator must comply with §112.9, or §112.11 (depending on the characteristics of the facility). Additionally, the sections for administrative and general rule requirements under 40 CFR part 112 apply as well (except for the security requirements under §112.7(g)).

The definition of "production facility" is consistent with the definition of "facility" in emphasizing flexibility in how a facility owner or operator can determine facility boundaries.

Tip – Production facility

A production facility for purposes of 40 CFR part 112 is one that is involved with producing or extracting petroleum crude oil from a reservoir and not any other type of oil production, such as animal fat and vegetable oil (AFVO) production.

- The definition of production facility addresses petroleum crude oil production, extraction, recovery, lifting, stabilization, separation or treatment and associated storage or measurement.
- The definition also includes terms associated with petroleum crude oil production, such as gathering lines and flowlines which are exclusively associated with upstream petroleum crude oil/gas production, not AFVO production or processing facilities. The term "oil or gas field" is used exclusively in upstream crude oil and gas production, not in AFVO production.

2.4.4 Drilling and Workover Facilities

Under the SPCC rule, the term "production facility" can encompass drilling and workover activities, as well as oil production operations. However, different specific provisions of the rule apply to these different activities. Drilling activities typically involve the initial establishment of an oil well: drilling the borehole, inserting, running, and cementing the casing, and completing the well to start the flow of well fluids to the surface. Workover operations involve maintenance or remedial work that may be necessary to improve productivity during the life of the well. Workover operations may also include activities associated with the initial well completion process. Both drilling and workover activities tend to be temporary in nature and are performed using mobile rigs and associated equipment. Thus a drilling and/or workover facility is considered a mobile facility. Mobile facilities may use a general Plan so that a new Plan need not be prepared each time the mobile facility is moved to a new site. For example, it is not necessary to amend the Plan for a drilling rig every time the operator moves the rig to drill a well in a field containing multiple wells (see 67 FR 47084, July 17, 2002). The same approach for mobile facilities applies to workover operations and activities.

For drilling and workover operations, the owner or operator is required to develop an SPCC Plan under §112.3(c) because a drilling or workover facility is considered a mobile facility. The administrative and general requirements of the SPCC rule (§§112.1 through 112.7), as well as the specific requirements in §112.10 (for onshore facilities) or §112.11 (for offshore facilities) apply to the facility.

Once the well is completed and the well fluids are flowing, the completion (workover) and/or drilling rig is removed from the site and production equipment, such as a pump or valve assembly, is set up to extract or control the flow of oil from the well. At this point, drilling and or workover activities have ceased and production has begun; the facility is considered an oil production facility. The processes performed at a typical oil production facility include extraction, separation and treatment, storage, and transfer. The owner or operator of an oil production facility is subject to the administrative and general requirements of the SPCC rule (§§112.1

through 112.7) as well as the specific requirements in §112.9 (for onshore facilities) or §112.11 (for offshore facilities). Typically, a gas plant is not considered an oil production facility.[28]

During the life of an oil well, maintenance or remedial work may be necessary to improve productivity. A specialized workover rig, equipment, and associated containers are brought on-site to perform maintenance or remedial activities. Workover activities are a distinct operation and may be conducted by a separate owner or operator, therefore, a workover operation may be considered a separate mobile facility and be described in a different SPCC Plan, separate from the oil production facility. Although production activities may temporarily cease during workover, if the production equipment and containers (such as those found in a tank battery) remain operable then the oil production facility owner/operator must maintain his own SPCC Plan during workover activities.

2.4.5 Definition of Farm

EPA defines ''farm'' in the SPCC rule in part by adapting the definition used by the National Agricultural Statistics Service (NASS) in its Census of Agriculture. NASS defines a farm as any place from which $1,000 or more of agricultural products were produced and sold, or normally would have been sold, during the census year. Operations receiving $1,000 or more in Federal government payments are counted as farms, even if they have no sales and otherwise lack the potential to have $1,000 or more in sales.

§112.2

Farm means a facility on a tract of land devoted to the production of crops or raising of animals, including fish, which produced and sold, or normally would have produced and sold, $1,000 or more of agricultural products during a year.

Note: The above text is an excerpt of the SPCC rule. Refer to 40 CFR part 112 for the full text of the rule.

EPA also considered the "farm tank" definition under the Underground Storage Tank (UST) regulations at 40 CFR part 280. As defined in 40 CFR 280.12, a farm tank is a tank located on a tract of land devoted to the production of crops or raising of animals, including fish.

The term ''farm'' includes fish hatcheries, rangeland, and nurseries with growing operations, but does not include laboratories where animals are raised, land used to grow timber, and pesticide aviation operations. This term also does not include retail stores or garden centers where the product of nursery farms is marketed, but not produced, nor does the Agency interpret the term ''farm'' to include golf courses or other places dedicated primarily to recreational, aesthetic, or other nonagricultural activities. Additionally, the definition of farm does not include agribusinesses because these businesses, e.g., oil marketing and distribution to farmers, are distinctly different from farms.

The definition of "farm" is narrower than the definition of "facility" and was originally promulgated to identify a subset of SPCC facilities subject to a compliance date extension. The definition of "facility" governs the overall applicability of 40 CFR part 112, and thus is used to determine whether the owner or operator (e.g., a

[28] EPA addressed this issue in a letter from R. Craig Matthiessen, Office of Emergency Management, to Roger Claff of the American Petroleum Institute (2010). See *Appendix H*.

farmer) is subject to the SPCC and/or FRP requirements of the rule and to determine the scope of his or her facility.

2.4.6 Examples of Aggregation or Separation

The following factors to determine the boundaries of a facility are not exclusive and simply serve as examples:

- Ownership, management, and operation of the buildings, structures, equipment, installations, pipes, or pipelines on the site;
- Similarity in functions, operational characteristics, and types of activities occurring at the site;
- Adjacency; or
- Shared drainage pathways (e.g., same receiving water bodies)

A lease may, at the owner or operator's discretion, constitute a facility, but does not necessarily create a facility. According to the definition of facility, contiguous or noncontiguous buildings, properties, leases, structures, installations, pipes, or pipelines under the ownership or operation of the same person may be considered separate facilities. A facility may also consist of parcels that are smaller or larger than an individual lease.

A facility may or may not be subject to the SPCC and FRP rule requirements depending on how the facility owner or operator aggregates buildings, structures or equipment and associated storage or type of activity. However, once the owner/operator determines the facility boundaries for SPCC applicability, then the same boundaries apply for determining applicability of the FRP rule requirements. An owner or operator may not characterize a facility so as to simply avoid applicability of the rule (for example, defining separate facilities around oil storage containers that are located side-by-side or within close proximity, and are used for the same purpose).

Following are six example scenarios of how a facility owner or operator may determine what is considered a "facility" for the purposes of an SPCC Plan. Each of these scenarios is hypothetical and is not intended to provide a policy interpretation for any specific existing facility.

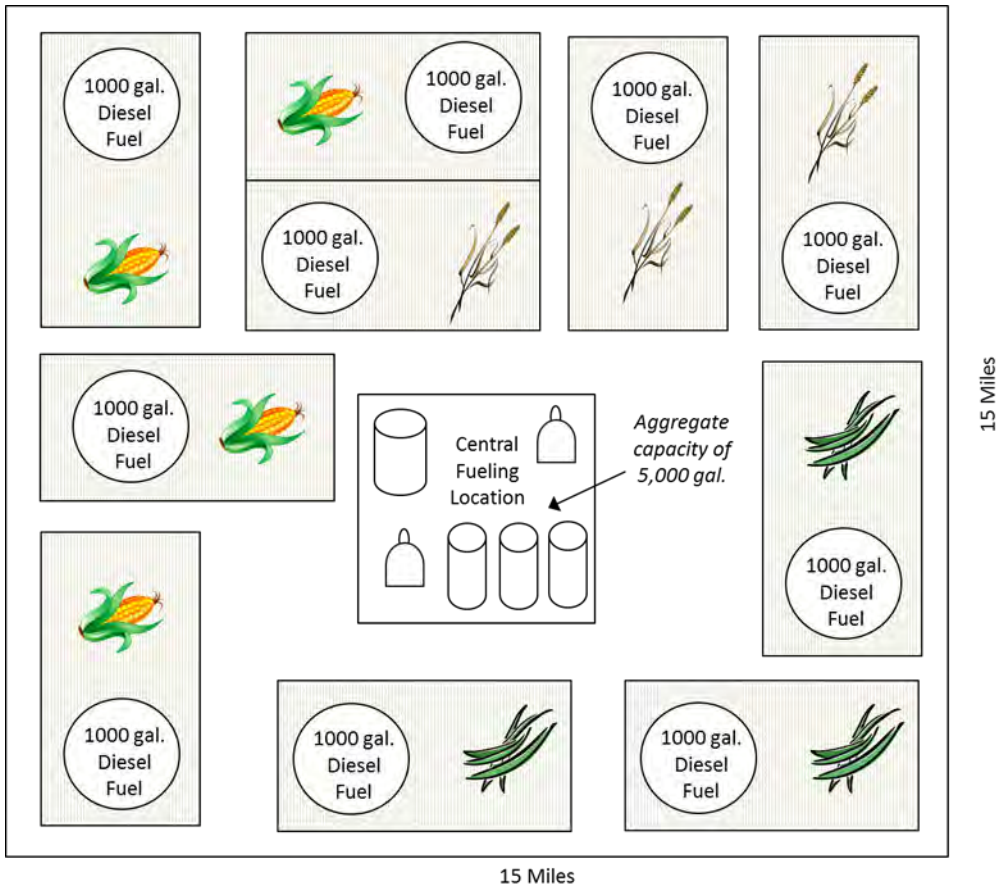
- **Scenario A.** Separation of Tracts at a Farm
- **Scenario B.** Separation of Leases at an Oil Production Facility
- **Scenario C.** Aggregation of Equipment at an Oil Production Facility
- **Scenario D.** Separation of Areas at a Military Base (or Other Large Facility)

- **Scenario E.** Separation of Functions at a Dual-Purpose Facility
- **Scenario F.** Separation of Equipment on Private Property

Scenario A. Separation of Tracts at a Farm

A farmer has one central fueling location and ten separate (either contiguous or non-contiguous) tracts of land (inclusive of owned and leased tracts) where various types of crops are grown. The central fueling location has several oil containers, with an aggregate storage capacity of 5,000 U.S. gallons of diesel fuel, gasoline, and hydraulic/lubrication oils. Each tract has one 1,000-gallon aboveground container of diesel fuel, used for fueling only the equipment operated on the tract. The tracts are located such that the containers are each several miles from each other. Each tract produces various types of crops, and thus the equipment is operated seasonally according to crop type and irrigation needs.

Figure 2-1: Separation of tracts at a farm.



Determination: Given the distance between containers, and the clear distinction between the operations that they support, each tract and the central fueling location can be considered a separate facility for the purposes of calculating oil storage capacity and determining the applicability of the SPCC rule. The fact that the tracts may be contiguous would be only one factor in the facility determination, and may allow the designation of the separate contiguous tracts as separate facilities, given the great distance and operational differences. In this example, each tract does not individually meet the aboveground storage capacity threshold for applicability of the SPCC rule (1,320 U.S. gallons). Therefore, no SPCC Plan is required for these containers. However, the central fueling location exceeds the SPCC rule aboveground storage capacity threshold. Assuming the farm is located such that a discharge of oil could reasonably pose a threat to navigable waters or adjoining shorelines, the farmer must prepare and implement an SPCC Plan for the central fueling area.

Under Section 311 of the Clean Water Act, the farmer, as an owner or operator of each facility, may still be liable for response costs and damages associated with any harmful quantities of oil discharged from the containers on the separate tracts into navigable waters or adjoining shorelines, even if an SPCC Plan is not required for these separate facilities.[29]

Alternative: To provide general protection and prevention measures against an oil discharge, the farmer may instead choose to include the ten diesel containers on the separate tracts in his Plan. The farmer may also choose to aggregate individual tracts of land that share similarities in operation and prepare SPCC Plans for those separate facilities. For example, combine the tracts of land that are used to grow the same crop and develop an SPCC Plan for each distinct facility.

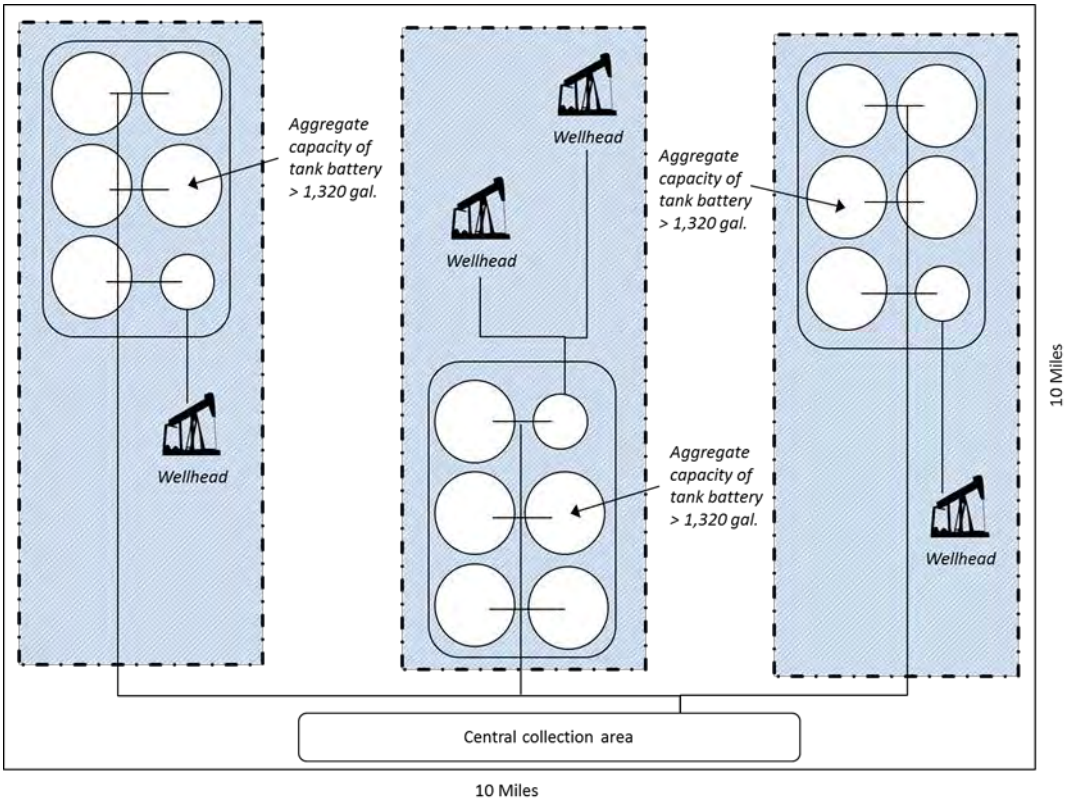
Scenario B. Separation of Leases at an Oil Production Facility

An oil production facility operator leases the right to extract oil from three parcels of land separated by large distances within one oil production field. The parcels may be contiguous or non-contiguous. Each of the parcels (or lease) is subject to a distinct lease agreement, consistent with all applicable state and local oil and gas laws and regulations. Each lease contains a tank battery storing more than 1,320 U.S. gallons of oil and one or more wellheads. Well fluids are separated and oil is stored in containers at each tank battery. Gathering lines from each tank battery flow to a central collection area that serves as a gathering station[30] and is managed by the same operator.

[29] The owner/operator may also be subject to liability under OPA and other statutes or regulations.

[30] This gathering station may also include an injection point to a transportation-related pipeline.

Figure 2-2: Separation of parcels at an oil production facility.



Determination: Given their geographic separation and the nature of the individual lease agreements, each lease could be considered a separate facility. Each tank battery stores a total aboveground capacity of oil greater than 1,320 U.S. gallons, so under such a scenario the operator must prepare and implement a separate SPCC Plan for each tank battery and its associated wellheads, flowlines, and equipment, as individual facilities. Any gathering lines that transport oil from these individual facilities into a centralized collection area involve the transportation of oil between facilities ("inter-facility") and are therefore <u>not</u> within EPA jurisdiction. These "inter-facility" gathering lines do not need to be included in the SPCC Plans. In this example, the central collection area is a separate facility and may be subject to SPCC requirements. If the central collection area facility meets the SPCC rule applicability criteria, then a separate SPCC Plan must be developed.

Alternative: Because the definition of facility is flexible, the operator could alternatively choose to consider all three parcels and the central collection area as one facility, based on his common ownership or operation of all of them. Under this approach, the operator would only need to prepare one SPCC Plan that covers the components of all parcels. Any gathering lines connecting the tank batteries of each parcel are then considered "intra-facility" gathering lines and must be included in the SPCC Plan.[31] It is also important to note

[31] Except when the intra-facility gathering lines are subject to the regulatory requirements of 49 CFR part 192 or 195. In that case,

that if an owner/operator aggregates oil storage so as to develop one SPCC Plan, he must then determine the facility boundaries the same way for the purposes of determining the applicability of the FRP rule requirements. Also note that an oil production facility may consist of parcels that are smaller or larger than an individual lease.

Scenario C. Aggregation of Equipment at an Oil Production Facility

An oil production facility owner operates one wellhead. Oil is treated in a 10-barrel (bbl) capacity heater-treater to separate the oil from produced water; the treated oil is then stored in several stock tanks that separately or combined would be subject to SPCC requirements until it is sold and transported off-site. The heater-treater separation equipment is located several feet away from the stock tanks, which hold both the oil and produced water.

These two areas may be physically separate and are protected by separate secondary containment berms, but the heater-treater is an integral component of an oil production facility, connected by piping, and under the control of the same operator. The heater-treater is a component of a larger process that would be incomplete without the ability to separate oil and produced water. Thus, all of these components should be aggregated together to comprise the oil production facility. In this circumstance, the heater-treater should not be considered a separate facility.

Similarly, an owner/operator could not separate a wellhead from the associated flowline or tank battery to call them distinct facilities. For example, an oil production facility owner operates one wellhead connected to the tank battery by a mile-long flowline. Despite the length of the flowline, the facility operator may not have a reasonable basis for separating the wellhead, flowline, and tank battery as distinct facilities with individual SPCC Plans. Similar to the heater-treater, the wellhead and tank battery are considered integral components of the larger process, and an oil production facility would be incomplete without including these two components. The flowline, whether several feet or several miles in length, is a necessary connection between the wellhead and tank battery, and all of these components must be included in one SPCC Plan.

---

the intra-facility gathering lines are exempt from the SPCC rule; however, the location of the exempt intra-facility gathering lines must be identified and marked as “exempt” on the facility diagram.

Figure 2-3: Aggregation of equipment at an oil production facility.

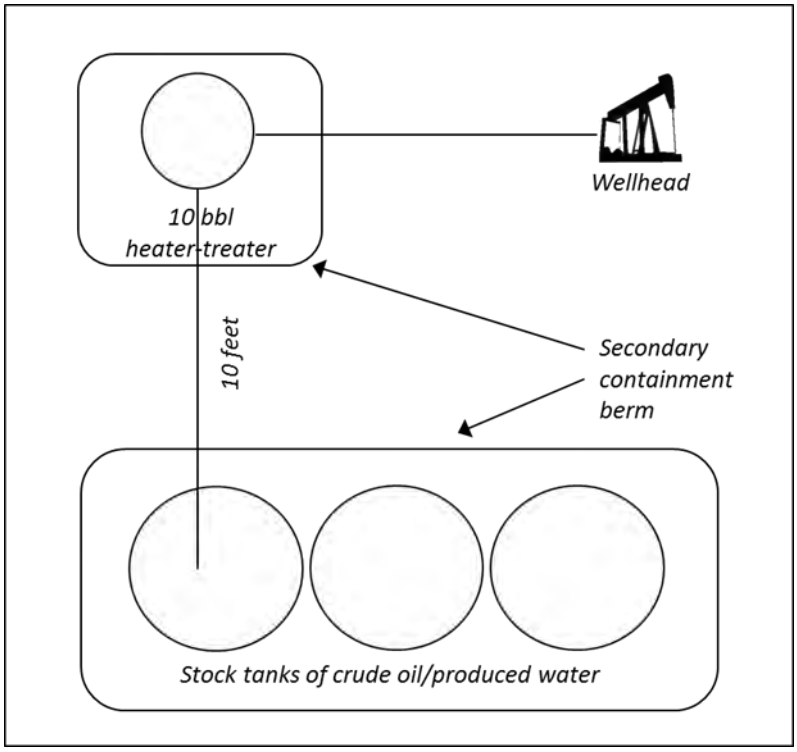
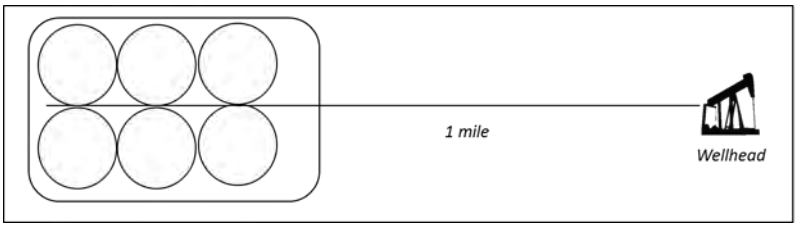


Figure 2-4: Mile-long flowline at an oil production facility.



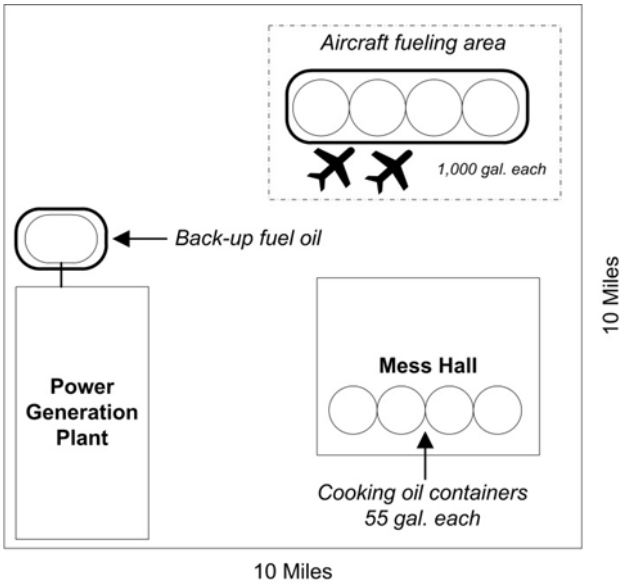
Determination: An SPCC Plan must include all of the components that together comprise a typical oil production facility. There may be no reasonable basis to determine that either of the facilities in these examples could be divided into separate, smaller facilities. While a facility owner or operator has some discretion in describing the parameters of his facility, he may not describe the boundaries of a facility unreasonably in an attempt to avoid regulation. The processes performed at a typical oil production facility include extraction, separation and treatment, storage, and transfer.

Scenario D. Separation of Areas at a Military Base (or Other Large Facility)

A military base is spread out over 10 square miles. Within the base, there are several areas where oil containers are located: a tank farm associated with an aircraft fueling area, back-up fuel oil for a small power generation plant, and a mess hall with several drums of cooking oil. Because different groups service, manage, or maintain the various tank farms and oil storage areas, these operators have agreed to calculate the aggregate

storage capacity of each of their operations separately to determine their SPCC rule applicability. The operations vary across these oil container locations, each with unique or specific characteristics.

Figure 2-5: Separation of areas at a military base (or other large facility).



Determination: In this example, different groups service, manage, or maintain the various tank farms and oil storage areas. The operations vary across these oil container locations, each with unique or specific characteristics; therefore, the operators can choose to calculate the aggregate storage capacity of each of their operations separately to determine SPCC rule applicability.

Alternative: However, the operators may also determine that it would be more efficient to prepare one SPCC Plan for the entire base. This determination would also be appropriate.

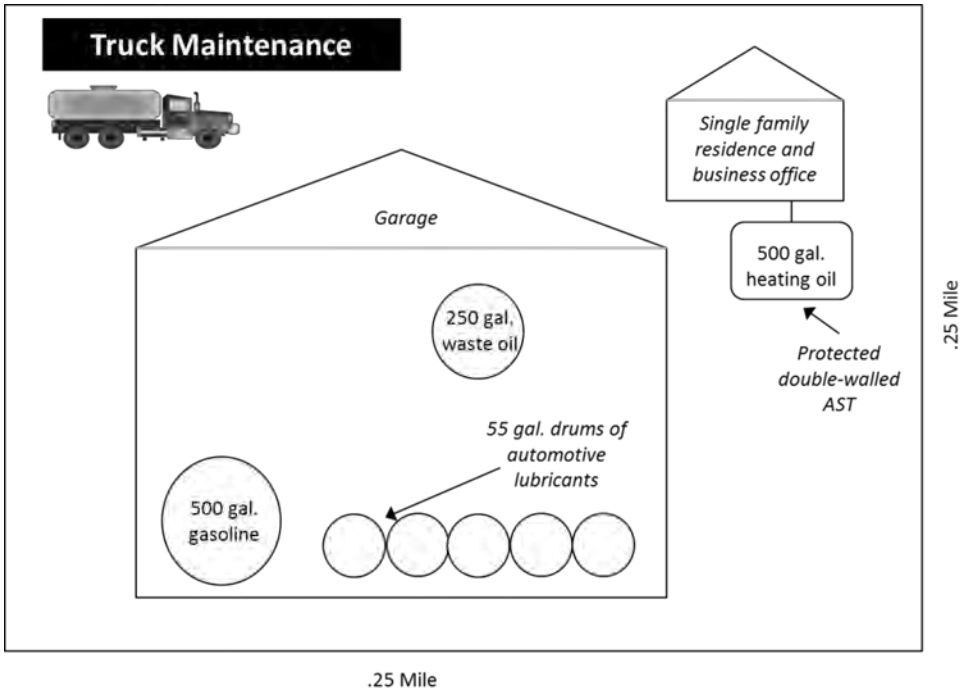
The same principles apply at other large facilities such as universities or airports. While a facility owner or operator has some discretion in describing the parameters of his facility, he may not unreasonably describe the boundaries of a facility to avoid regulation.

Regardless of how the facility boundaries are defined, heating oil containers associated with single-family residences within a military base (or other large-footprint facility) are exempt from the SPCC rule.

Scenario E. Separation of Functions at a Dual-Purpose Facility

The owner of a truck maintenance company operates his business from a site that also includes his single-family residence. The business office is located in his residence. The entire building is heated with one 500-gallon heating oil container. In an adjacent garage, he has one 500-gallon gasoline container, one 250-gallon waste oil container, and five 55-gallon drums of various automotive lubricants.

Figure 2-6: Separation of functions at a dual-purpose facility.



Determination: In considering whether the facility is subject to the SPCC rule, this business owner can conclude that the heating oil container is exempt from the rule because it is associated with his home, and the function of heating his home is necessary regardless of the presence of his business operations. Because the total storage capacity of the remaining containers does not meet the aboveground storage capacity threshold for applicability of the SPCC rule (1,320 U.S. gallons), the owner is not subject to the SPCC rule.

Tip – Containers owned or operated by someone else

One commonly asked question is how an owner/operator should address a container located at the facility that is owned or operated by someone else.

The owner or operator of a facility that includes a container being used by another person that is not under his or her operational control should coordinate with that person to determine who will prevent spills from that container.

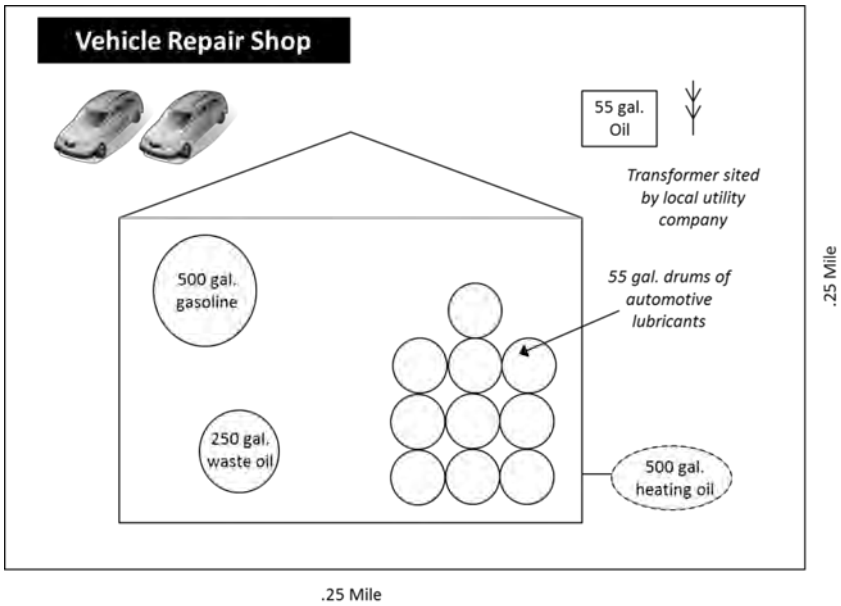
For example, transformers, or other energized electrical equipment, that are located on an easement and are under the operational control of the local electrical utility may be addressed separately by the utility. The owner/operator of the facility would typically not be required to include these containers in the SPCC Plan or on the facility diagram. The owner/operator should coordinate with the electric utility on how to address spill prevention procedures for this equipment.

This determination by the plan holder must be based on site-specific factors.

Scenario F. Separation of Equipment on Private Property

The owner of a vehicle repair shop maintains one 500-gallon gasoline container, one 250-gallon waste oil container, ten 55-gallon drums of various automotive lubricants, and one 500-gallon completely buried heating oil container for use at the facility. The local utility company has also sited a transformer, with a capacity to hold 55 U.S. gallons of transformer oil, on the repair shop property.

Figure 2-7: Separation of equipment on private property.



Determination: In calculating total facility oil storage capacity, the property owner is not required to consider the volume of the transformer because it is owned and operated by another entity, and the transformer may be covered under the utility company's Plan. However, because it is located on the repair shop property, the facility owner/operator should coordinate with the utility company on how to address oil discharges from the transformer. Under Section 311 of the Clean Water Act, the repair shop owner/operator, in addition to the transformer owner/operator, may be liable for any harmful quantities of oil discharged from the transformer when it is located on his property.

The total aboveground oil storage capacity of the repair shop is less than 1,320 U.S. gallons when the transformer is not included in the calculation. The heating oil container counts separately toward the facility's completely buried storage capacity because it is not used "solely at a single-family residence." However, the facility aggregate completely buried capacity is less than the 42,000 gallons threshold. Therefore, the facility is not subject to the SPCC rule.

2.4.7 Natural Gas Production/Treatment Facilities and Pipelines

As described in *Section 2.2.5* above, EPA does not regulate natural gas under the SPCC rule. However, natural gas condensate is considered an oil and is regulated under the SPCC rule. For the purposes of

determining SPCC applicability, containers with 55 gallons or more in capacity storing condensate must be included in a natural gas facility's total oil storage capacity calculation. Ancillary oil storage in other areas of the facility, such as fuel or lubrication oil, and oil-filled equipment, is also counted. Natural gas production or treatment facilities and pipeline systems commonly have associated oil storage, including oil-containing equipment such as compressors, drip tanks, and separators that may store motor oil, lubricants, crude oil impurities removed from the gas stream, and liquid condensate. Equipment that compresses or pumps the natural gas is not regulated unless there is oil-filled operational equipment associated with it that meets the applicability requirements of the rule.

The definition of "production facility" in §112.2 specifies that an oil production facility involves the "…production, extraction, recovery, lifting, stabilization, separation or treating *of oil*." (emphasis added.) Therefore, any natural gas treatment facility that does not produce oil or condensate is not regulated as a *production* facility under the SPCC requirements, but may be regulated as a bulk oil storage facility because of aboveground ancillary oil storage, including oil-filled equipment. For the following scenarios, the general and administrative provisions of the rule (§§112.1 through 112.7) apply, as well as the more specific requirements described.

Following are five example scenarios of facilities that are involved in producing or treating natural gas and how the SPCC rule would apply for each. Each of these scenarios is hypothetical and is not intended to provide a policy interpretation for any specific existing facility.

- **Scenario A** Oil and Gas Production Facility
- **Scenario B** "Wet Gas" Production Facility
- **Scenario C** "Dry Gas" Production Facility
- **Scenario D** Gas Processing/Treatment Facility/Plant
- **Scenario E** Facility Supporting a Gas Pipeline

Scenario A Oil and Gas Production Facility

The wellhead at this type of facility produces a mixture of oil, gas, and produced water. Because this facility produces oil from the wellhead, it is considered an oil production facility according to the SPCC rule and must comply with the requirements at §112.9.

Oil production facilities can include piping with both oil and gas phases. In this instance, such a facility's dual-phase flowlines and intra-facility gathering lines (i.e., those carrying both gas and liquid phase hydrocarbon)

are subject to the SPCC requirements[32] because if the lines were to rupture or leak, they may discharge oil to navigable waters or adjoining shorelines in quantities that may be harmful as defined in 40 CFR part 110.

Scenario B "Wet Gas" Production Facility

The wellhead at this type of facility produces a mixture of gas, produced water, and condensate. Condensate that is liquid at atmospheric pressures and temperatures is considered an oil, and the facility could be subject to the SPCC rule if it meets the SPCC rule applicability criteria. Because the facility produces oil, this facility is considered an oil production facility and must comply with the requirements at §112.9 if subject to the SPCC rule. The presence of any gas treatment at the facility prior to the point of custody transfer (e.g., meter) into a gas pipeline would not affect the determination that this facility is an oil production facility.

Scenario C "Dry Gas" Production Facility

The wellhead at this facility produces a mixture of gas and produced water only. A dry gas production facility that produces natural gas from a well (or wells) but does not also produce condensate or crude oil that can be drawn off the tanks, containers, or other production equipment at the facility is not subject to the SPCC rule. EPA has clarified that a dry gas production facility does not meet the description of an "oil production, oil recovery, or oil recycling facility." Therefore, a dry gas facility may be eligible for the wastewater treatment exemption under §112.1(d)(6).[33] See the excerpt "*Notice concerning certain issues pertaining to the July 2002 Spill Prevention, Control, and Countermeasure (SPCC) rule*" below.

However, if the aboveground ancillary storage of oil at a dry gas production facility is greater than 1,320 U.S. gallons, and the facility otherwise meets the applicability of the rule, the facility is regulated under the SPCC rule and must comply with the requirements for onshore facilities at §112.8. Because the well does not produce recoverable oil or condensate, the facility does not meet the definition for an oil production facility under the SPCC rule.

---

32 Intra-facility gathering lines subject to DOT regulation under 49 CFR parts 192 or 195 are exempt from SPCC rule requirements (§112.1(d)(11)).

33 "Notice Concerning Certain Issues Pertaining to the July 2002 Spill Prevention, Control, and Countermeasure (SPCC) Rule," 69 FR 29728, May 25, 2004.

Notice concerning certain issues pertaining to the July 2002 Spill Prevention, Control, and Countermeasure (SPCC) rule

The Agency has been asked whether produced water tanks at dry gas facilities are eligible for the SPCC rule's wastewater treatment exemption at 40 CFR 112.7(d)(6). A dry gas production facility is a facility that produces natural gas from a well (or wells) from which it does not also produce condensate or crude oil that can be drawn off the tanks, containers or other production equipment at the facility.

The SPCC rule's wastewater treatment exemption excludes from 40 CFR part 112 "any facility or part thereof used exclusively for wastewater treatment and not used to satisfy any requirement of this part." However, for the purposes of the exemption, the "production, recovery, or recycling of oil is not wastewater treatment." In interpreting this provision, the preamble to the final rule states that the Agency does "not consider wastewater treatment facilities or parts thereof at an oil production, oil recovery, or oil recycling facility to be wastewater treatment for purposes of this paragraph."

It is our view that a dry gas production facility (as described above) would not be excluded from the wastewater treatment exemption based on the view that it constitutes an "oil production, oil recovery, or oil recycling facility." As discussed in the preamble to the July 2002 rulemaking, "the goal of an oil production, oil recovery, or oil recycling facility is to maximize the production or recovery of oil. * * *" 67 FR 47068. A dry gas facility does not meet this description.

(See 69 FR 29729, 29730, May 25, 2004.)

Scenario D Gas Processing/Treatment Facility/Plant

This type of facility receives gas after it is separated from oil and produced water. The gas typically contains condensate, which is removed from the gas stream at this facility. Petroleum distillate that is produced by natural gas wells and stored at atmospheric pressures and temperatures is considered an oil. If the total aboveground storage capacity for condensate tanks and all other ancillary oil storage is greater than 1,320 gallons, and the facility otherwise meets the applicability of the rule, then this facility is considered a bulk storage facility subject to the requirements under §112.8. EPA has addressed this issue in a letter[34] to API, dated December 10, 2010, that details the Agency's position on how SPCC requirements apply to gas plants/compression stations.

However, when gas plant or compression activities are co-located at an SPCC-regulated oil production facility with a tank battery, then the containers associated with gas separation that store or process oil (i.e., separation vessels containing oil/ liquid condensate) are typically considered part of the oil production facility operations and therefore subject to the onshore oil production facility requirements under 40 CFR part 112.9 (or §112.11 for offshore facilities).

Scenario E Facility Supporting a Gas Pipeline

At a facility supporting a gas pipeline, EPA regulates compressors or equipment containing oil (including condensate when it turns into liquid at atmospheric temperatures and pressures), but not gas-filled portions of

[34] See *Appendix H* for the letter from R. Craig Matthiessen, Office of Emergency Management, to Roger Claff of the American Petroleum Institute (2010).

equipment. If the aboveground oil storage capacity is greater than 1,320 gallons, and the facility otherwise meets the applicability of the rule, the facility is considered a bulk storage facility under the SPCC rule subject to the requirements under §112.8.

2.5 "Non-Transportation Related" – EPA/DOT Jurisdiction

Facilities regulated under 40 CFR part 112 are divided into three categories: transportation-related facilities, non-transportation-related facilities, and complexes. The delineation between transportation-related and non-transportation-related facilities has been established through a series of Executive Orders (EOs) and Memoranda of Understanding (MOUs) as described below. Onshore and certain offshore non-transportation-related facilities (and portions of a complex) are subject to the SPCC regulation, provided they meet the other applicability criteria set forth in §112.1.

A 1971 MOU between EPA and DOT clarifies the types of facilities, activities, equipment, and vessels that are meant by the terms "transportation-related onshore and offshore facilities" and "non-transportation-related onshore and offshore facilities." DOT delegated authority over vessels and transportation-related onshore and offshore facilities to the Commandant of the U.S. Coast Guard.[35] Sections of the MOU between EPA and DOT are included in Appendix A of 40 CFR part 112. Section 112.1(d)(1)(ii) specifically exempts from SPCC applicability any equipment, vessels, or facilities subject to the authority and control of the DOT as defined in this MOU.

A 1994 MOU among the Secretary of the Interior, the Secretary of Transportation, and the Administrator of EPA establishes the jurisdictional responsibilities for offshore facilities, including pipelines. This MOU can be found in Appendix B of 40 CFR part 112. Section 112.1(d)(1)(iii) specifically exempts from SPCC applicability any equipment, vessels, or facilities subject to the authority of the DOT or DOI as defined in this MOU.

Table 2-2 provides examples of transportation-related and non-transportation-related facilities as the concepts apply to the SPCC rule applicability. Some equipment, such as loading arms and transfer hoses, may be considered either transportation-related or non-transportation-related depending on their use.

§112.2

Complex means a facility possessing a combination of transportation-related and non-transportation-related components that is subject to the jurisdiction of more than one Federal agency under section 311(j) of the CWA.

Note: The above text is an excerpt of the SPCC rule. Refer to 40 CFR part 112 for the full text of the rule.

[35] The USCG was reorganized under the Department of Homeland Security in March 2003.

Table 2-2: Examples of transportation-related and non-transportation-related facilities from the 1971 DOT-EPA MOU.

Transportation-related Facilities (DOT Jurisdiction)	Non-Transportation-related Facilities (EPA Jurisdiction)
– Onshore and offshore terminal facilities, including transfer hoses, loading arms, and other equipment used to transfer oil in bulk to or from a vessel, including storage tanks and appurtenances for the reception of oily ballast water or tank washings from vessels – Transfer hoses, loading arms, and other equipment appurtenant to a non-transportation-related facility used to transfer oil in bulk *to or from a vessel* – Interstate and intrastate onshore and offshore pipeline systems – Highway vehicles and railroad cars that are used for the transport of oil – Equipment used for the fueling of locomotive units, as well as the rights-of-way on which they operate.	– Fixed or mobile onshore and offshore oil drilling and oil production facilities – Oil refining and storage facilities – Industrial, commercial, agricultural, and public facilities that use and store oil – Waste oil treatment facilities – Loading racks, transfer hoses, loading arms, and other equipment used to transfer oil in bulk *to or from highway vehicles or railroad cars* – Highway vehicles, railroad cars, and pipelines used to transport oil exclusively within the confines of non-transportation-related facility

A facility with both transportation-related and non-transportation-related activities is a "complex" and is subject to the dual jurisdiction of EPA and DOT or USCG. The jurisdiction over a component of a complex is determined by the activity occurring at that component. An activity might at one time subject a facility to one agency's jurisdiction, and a different activity at the same facility using the same structure or equipment might subject the facility to the jurisdiction of another agency. The 1971 DOT-EPA MOU defines the activities that are subject to either EPA or DOT jurisdiction. *Appendix H* includes drawings that show EPA's regulatory jurisdiction at complexes.[36]

The sections below describe common scenarios that have raised jurisdictional questions regarding the distinction between transportation-related and non-transportation-related containers or facilities for applicability of SPCC requirements. EPA inspectors should evaluate the intended activity carefully because the determination of jurisdiction is not always straightforward.

[36] See EPA Jurisdiction at Complexes in *Appendix H*.

FYI – EPA/DOT jurisdiction

Equipment, operations, and facilities are subject to DOT jurisdiction when they are engaged in activities subject to DOT jurisdiction. If those same facilities are also engaged in activities subject to EPA jurisdiction (such facilities are considered a ''complex''), such activities would subject the equipment, operation, or facility to EPA jurisdiction, as well. During the development of the FRP rule, EPA and other federal agencies with jurisdiction under the Oil Pollution Act (OPA) and Executive Order 12777 (including DOT) met to create an implementation strategy that minimized duplication, wherever practicable and recognized State oil pollution prevention and response programs. One of the critical outgrowths of these efforts was the development of a definition for, and a consistent approach to regulate "complexes."

The jurisdiction over a component of a complex is determined by the activity involving that component. An activity at one time might subject a facility to one agency's jurisdiction, while a different activity at the same facility using the same structure, container or equipment might subject the facility to the jurisdiction of another agency.

(see 74 FR 58804, November 13, 2009)

2.5.1 Tank Trucks

EPA regulates tank trucks (or mobile refuelers) as "mobile/portable containers" under the SPCC rule if they operate exclusively within the confines of a non-transportation-related facility. For example, a tank truck that moves within the confines of a facility and only leaves the facility to obtain more fuel (oil) would be considered to distribute fuel exclusively at one facility. This tank truck would be subject to the SPCC rule if it, or the facility, contained above the regulatory threshold amount (see *Section 2.7*) and there was a reasonable expectation of discharge to navigable waters or adjoining shorelines. Similarly, a mobile refueler that fuels exclusively at one site, such as at an airport or construction site, would be subject to the SPCC rule. However, if the tank truck only distributed fuel to multiple off-site facilities and did not perform fueling activities at the home base, the tank truck would be transportation-related, and regulated by DOT. Additionally, EPA regulates containers which were formerly used for transportation, such as a truck or railroad car, and are now used to store oil (i.e., no longer used for a transportation purpose) as a bulk storage container (see 67 FR 47075, July 17, 2002).

Tank trucks that are used in interstate or intrastate commerce can also be regulated if they are operating in a fixed, non-transportation mode. For example, if a home heating oil truck makes its deliveries, returns to the facility, and parks overnight with a partly filled fuel tank, it is subject to the SPCC rule if it, or the facility has a capacity above the threshold amount (see *Section 2.7*), and there is a reasonable expectation of discharge to navigable waters or adjoining shorelines.[37] However, if the home heating oil truck's fuel tank contains no oil when it is parked at the facility, other than any residual oil present in an emptied vehicle, it would be regulated only by DOT.[38] For more information on the secondary containment requirements for

[37] In this case, the facility would include the truck storage capacity in its aggregate capacity determination in order to determine whether it is above the 1,320 gallon aboveground threshold for SPCC applicability.

[38] EPA addressed this scenario in a letter from Stephen Heare, Office of Emergency and Remedial Response, to Melissa Young of Petroleum Marketers Association of America (2001). See *Appendix H*.

mobile refuelers and other non-transportation-related tank trucks, refer to *Chapter 4: Secondary Containment and Impracticability*.

2.5.2 Railroad Cars

DOT regulates railroad cars used for the transport of oil in interstate or intrastate commerce and the related equipment and appurtenances. DOT jurisdiction includes railroad cars that are passing through a facility or are temporarily stopped on a normal route. EPA regulates railroad cars under the SPCC rule if they are operating exclusively within the confines of a non-transportation-related facility. EPA regulates both transfers to or from railroad cars and when the railroad cars serve as non-transportation-related storage at an SPCC-regulated facility.

When the railcar is serving as non-transportation-related storage, if the railroad car has a storage capacity above the regulatory threshold amount of oil, and there is a reasonable expectation of discharge to navigable waters or adjoining shorelines, the railroad car itself may become a non-transportation-related facility, even if no other containers at the property would qualify it as an SPCC-regulated facility.[39]

2.5.3 Loading/Unloading Activities

DOT regulates equipment used for the fueling of locomotive units, as well as the rights-of-way on which they operate. EPA regulates the activity of loading or unloading oil in bulk into storage containers (such as those on tank trucks or railroad cars), as well as all equipment involved in this activity (e.g., a hose or loading arm attached to a storage tank system). Different requirements apply to oil transfer areas and to loading/unloading racks at a regulated facility. A transfer area is any area of a facility where oil is transferred between bulk storage containers and tank trucks or railroad cars. These areas are subject to the general secondary containment requirements in §112.7(c). If a "loading/unloading rack" (as defined in §112.2) is present, the requirements of §112.7(h) apply to the loading/unloading rack area. For more information, refer to *Chapter 4: Secondary Containment and Impracticability* which discusses secondary containment requirements for loading/unloading areas and racks.

2.5.4 Marine Terminals

A marine terminal is an example of a "complex" subject to both U.S. Coast Guard (USCG) and EPA jurisdiction. The jurisdictional boundary of a complex facility for both USCG and EPA is defined in 33 CFR part 154, *Facilities Transferring Oil or Hazardous Material in Bulk* under the definition of a marine transportation-related facility (MTR facility) in §154.1020.The USCG regulates the pier structures, transfer hoses, hose-piping connection, containment, controls, and transfer piping associated with the transfer of oil between a vessel and an onshore facility. EPA regulates the tanks, internal piping, loading racks, and vehicle/rail operations that are completely within the non-transportation portion of the facility. EPA jurisdiction begins at the first valve inside secondary containment. If there is no secondary containment, EPA jurisdiction begins at the valve or manifold

[39] EPA addressed the applicability of the SPCC rule to railroad cars by addressing specific scenarios in a letter to the Safety-Kleen Corporation in July 2000. See *Appendix H*.

adjacent to the storage tank. *Appendix H* includes drawings that show EPA's regulatory jurisdiction at complexes, including an example of a marine terminal.[40]

2.5.5 Vessels (Ships/Barges)

The U.S. Coast Guard regulates the loading or unloading of oil in bulk from a vessel to an onshore facility, as well as the oil-carrying vessel and the connecting piping (33 CFR part 155, Oil or Hazardous Material Pollution Prevention Regulations for Vessels). In this scenario, a vessel is a ship or a barge. The oil passes from the USCG's jurisdiction to that of the EPA when it passes the first valve inside the secondary containment for the storage container at an otherwise regulated facility. If there is no secondary containment, EPA's jurisdiction begins at the first valve or manifold closest to the storage container. Storage tanks and appurtenances for the reception of oily ballast water or tank washings from vessels are under USCG jurisdiction.

Vessels themselves are specifically exempt from 40 CFR part 112 under §112.1(d)(1)(iii). EPA also clarified that barges or other watercraft that store oil, and have been determined by the Coast Guard to be permanently moored, are no longer vessels, but storage containers that are part of an offshore facility (67 FR 47075, July 17, 2002).

2.5.6 Breakout Tanks

Although breakout tanks can be used to relieve surges in an oil pipeline system or to receive and store oil transported by a pipeline for reinjection and continued transportation by pipeline, they are sometimes used for bulk storage (i.e., non-transportation-related storage). Thus, breakout tanks may be regulated by EPA, DOT, or both depending on how the tank is used. Breakout tanks used solely to relieve surges in a pipeline, not used for any non-transportation-related activity (i.e., pipeline-in and pipeline-out configuration, and with no transfer to other equipment/mode of transportation such as a tank truck), are not subject to EPA jurisdiction. Bulk storage containers used to store oil while also serving as a breakout tank for a pipeline or other transportation-related purposes may be subject to both EPA and DOT jurisdiction.[41] Determining agency jurisdiction can be difficult and should be treated on a case-by-case basis. However, additional information can be found in *Appendix H* which includes drawings that show EPA's regulatory jurisdiction at complexes.[42]

---

40 See EPA Jurisdiction at Complexes.

41 See the 1971 MOU between DOT and EPA (Appendix A of 40 CFR part 112).

42 See EPA Jurisdiction at Complexes for specific examples.

2.5.7 Motive Power

Motive power containers are located in or on a motor vehicle and serve as an onboard bulk storage container used primarily to power the movement of a motor vehicle or ancillary onboard oil-filled operational equipment. Motive power containers on vehicles used solely at non-transportation-related facilities fall under EPA jurisdiction but are exempt from the SPCC rule. See *Section 2.8.6* for more information.

§112.2

Motive power container means any onboard bulk storage container used primarily to power the movement of a motor vehicle, or ancillary onboard oil-filled operational equipment. An onboard bulk storage container which is used to store or transfer oil for further distribution is not a motive power container. The definition of motive power container does not include oil drilling or workover equipment, including rigs.

Note: The above text is an excerpt of the SPCC rule. Refer to 40 CFR part 112 for the full text of the rule.

2.5.8 Flowlines and Gathering Lines

Any pipeline or piping that transports oil between facilities or from a facility to a vessel is considered transportation-related, and is therefore outside the jurisdiction of EPA and not subject to the SPCC rule. EPA recognizes that gathering lines are often outside of the Agency's jurisdiction because they transport oil outside of an oil production facility.

However, EPA has jurisdiction over non-transportation-related facilities, including pipelines that transport oil within a facility. The definition of ''facility'' as it applies to the SPCC rule is flexible; depending upon how an owner/operator defines his facility, an oil production facility may also include gathering lines. A typical oil production facility includes a wellhead, a tank battery (including, but not limited to, separation equipment, stock oil containers and produced water containers), and the flowlines that transfer the oil and well fluids from the wellhead to the tank battery. A flowline may also connect a tank battery to an injection well. If multiple tank batteries are included as part of the same facility for purposes of developing one SPCC Plan, then any gathering lines that connect the tank batteries, or flow to a central collection or gathering area or centralized tank battery within the facility boundaries, must also be included in the SPCC Plan. EPA considers any gathering lines within the boundaries of a facility to be ''intra-facility gathering lines'' and within EPA's jurisdiction for the purposes of SPCC rule applicability (72 FR 58406 to 58407, October 15, 2007). *Appendix H* includes drawings that show EPA's regulatory jurisdiction at complexes, including an example of an oil production facility with gathering lines.[43]

The exemption of certain intra-facility gathering lines from SPCC rule requirements is discussed in *Section 2.8.10*.

[43] See EPA Jurisdiction at Complexes.

FYI – Flowlines and gathering lines

Flowlines are the piping that transfer crude oil and well fluids from the wellhead to the tank battery where separation and treatment equipment are typically located. A flowline may also connect a tank battery to an injection well. Flowlines are relatively small diameter steel or fiberglass piping (generally less than four inches). Depending on the size of the oil field, flowlines may run for hundreds of feet to a tank battery.

Gathering lines are the piping or pipelines that transfer the crude oil product between tank batteries, within or between facilities. Gathering lines often originate from an oil production facility's lease automatic custody transfer (LACT) unit, which transfers oil to other facilities involved in gathering, refining or pipeline transportation operations.

2.6 Reasonable Expectation of Discharge to Navigable Waters in Quantities That May Be Harmful

2.6.1 Definition of "Discharge" and "Discharge as Described in §112.1(b)"

According to §112.1(b), the SPCC rule applies to certain facilities that could "reasonably be expected to discharge oil in quantities that may be harmful, as described in part 110 of this chapter..." The Discharge of Oil regulation at 40 CFR part 110 (also referred to as the "sheen rule") defines a discharge of oil into or upon the navigable waters of the United States or adjoining shorelines in quantities that may be harmful under the CWA as that which:

- Causes a sheen or discoloration on the surface of the water or adjoining shorelines;
- Causes a sludge or emulsion to be deposited beneath the surface of the water or upon adjoining shorelines; or
- Violates an applicable water quality standard.[44]

A discharge meeting any of the above criteria triggers requirements to report to the National Response Center (NRC). The failure to report such a discharge may result in criminal sanctions under the CWA. The appearance of a "sheen" on the surface of the water is often used as a simple way to identify harmful discharges of oil that should be reported. However, the presence of a sludge or emulsion or of another deposit of oil beneath the water surface, or the violation of an applicable water quality standard also indicates a harmful discharge regardless of whether there is a sheen on the water surface.

Section 311 of the CWA defines and prohibits certain "discharges" of oil. This definition is also codified in 40 CFR part 112. A "discharge" as defined in §112.2 includes, but is not limited to, any spilling, leaking, pumping, pouring, emitting, emptying, or dumping of any amount of oil no matter where it occurs. It excludes certain discharges associated with §402 of the CWA and §13 of the River and Harbor Act of 1899. The primary

[44] Water Quality Standards define the goals for a waterbody by designating its uses, setting criteria to protect those uses, and establishing provisions such as antidegradation policies to protect waterbodies from pollutants. For more information on water quality standards see http://water.epa.gov/scitech/swguidance/standards/upload/WQS_basic_factsheet.pdf

distinction between the §112.2 and §112.1(b) definitions of discharge is that a discharge as described in §112.1(b) is a violation of §311 of the Clean Water Act, whereas a §112.2 discharge includes discharges that do not reach navigable waters or adjoining shorelines. For example, if a tank leaks a puddle of oil into a building's basement, this would be considered a discharge of oil under §112.2, but is not necessarily a violation of the CWA because the oil did not reach a navigable water or adjoining shoreline (and would not be a discharge as described in §112.1(b)).

The SPCC regulation includes requirements for corrective action as well as additional reporting requirements. For example, in §112.8(c)(10), the owner or operator of a facility is required to promptly correct visible discharges that result in a loss of oil from a container. A discharge of any amount would need to be cleaned up, but would not be considered a violation of the spill prohibition (a discharge as described in §112.1(b)), unless it reaches a navigable water or adjoining shorelines. Additionally, if a facility discharged more than 42 U.S. gallons of oil in each of two discharges as described in §112.1(b) over a 12-month period, the owner or operator would be required to report each spill to the NRC, clean up the spill, and submit a report to the Regional Administrator, and may be required to amend its Plan. The same is true if the facility has a single discharge as described in §112.1(b) of more than 1,000 U.S. gallons. For more information on these reporting requirements, see §112.4 of the rule.[45]

§112.1(b)

...this part applies to any owner or operator of a non-transportation-related onshore or offshore facility engaged in drilling, producing, gathering, storing, processing, refining, transferring, distributing, using, or consuming oil and oil products, which due to its location, ***could reasonably be expected to discharge oil in quantities that may be harmful, as described in part 110 of this chapter...***

Note: The above text is an excerpt of the SPCC rule. Refer to 40 CFR part 112 for the full text of the rule. ***Emphasis added.***

2.6.2 Reasonable Expectation of Discharge

The SPCC rule applies only to facilities that, due to their location, can reasonably be expected to discharge oil as described in §112.1(b). The rule does not define the term "reasonably be expected." The owner or operator of each facility must determine the potential for a discharge from his/her facility. According to §112.1(d)(1)(i), this determination must be based solely upon consideration of the geographical and locational aspects of the facility. An owner or operator should consider the location of the facility in relation to a stream, ditch, gully, or storm sewer; the volume of material likely to be spilled; drainage patterns; and soil conditions. An owner or operator may not consider constructed features, such as dikes, equipment, or other manmade structures that prevent, contain, hinder, or restrain a discharge as described in §112.1(b), when making this determination.[46]

[45] When determining the applicability of this SPCC reporting requirement, the gallon amount(s) specified (either 1,000 or 42) refers to the amount of oil that actually reaches navigable waters or adjoining shorelines not the total amount of oil spilled. EPA considers the entire volume of the discharge to be oil for the purposes of these reporting requirements.

[46] Certain man-made features, such as building walls, basement structures, and drainage systems may be taken into consideration in determining *how to comply* with the SPCC requirements.

A facility owner or operator, however, should consider the presence of manmade structures that may serve to transport discharged oil to navigable waters, such as sanitary or storm water drainage systems, even if they lead to a publicly owned treatment work (POTW) prior to ultimate discharge into navigable waters. The presence of a treatment system such as a POTW cannot be used to determine that the facility is not reasonably expected to discharge to navigable waters or adjoining shorelines. POTWs can fail to contain oil. They are not designed to handle oil discharges and are on occasion forced to bypass to receiving waterbodies during extreme weather events or when upsets occur in the treatment system.

The following factors[47] may be useful to consider in determining whether there is a reasonable expectation of a discharge:

- ***Past discharges*** of oil from the facility or a neighboring facility that reached a navigable water or adjoining shoreline may indicate that another could be reasonably expected;
- ***Facility location*** relative to navigable waters, a watercourse and/or intervening natural drainage could cause a discharge to the navigable waters to be reasonably expected;
- ***On-site conduits and certain underground features***, such as sewer lines, storm sewers, power or cable lines, or groundwater could facilitate the transport of discharged oil off-site to navigable waters;
- ***Unique geological or geographic features*** could facilitate the transport of discharged oil off-site to navigable waters;
- ***Precipitation runoff*** could transport oil into navigable waters; and
- ***Quantity and nature of oil stored***.

If an owner or operator makes a determination that, due to the location, the facility cannot reasonably be expected to discharge oil as described in §112.1(b), he should be prepared to provide the rationale and any supporting documentation to an EPA inspector that explains why the facility does not have an SPCC Plan.

FYI – Tools to determine reasonable expectation of discharge

While EPA does not endorse or recommend any particular modeling programs, the Agency recognizes that there are software tools available to aid in making the reasonable expectation of discharge determination, which have been used by various industry sectors. Such tools may combine data concerning the location of facilities with respect to navigable waters, geographical features, type of oil stored, soil type, and other factors as described above, to make site-specific estimations. The SPCC Plan preparer and/or certifying PE may determine whether any software tool is appropriate for his or her specific circumstances, and should adequately document the input variables in the SPCC Plan.

[47] These are examples of factors to provide guidance and are not mandatory. However, a facility owner/operator may wish to take a conservative approach and consider all of these factors when determining reasonable expectation of a discharge from the facility.

2.6.3 Geographic Scope

EPA revised the geographic scope described in §112.1(b) of the SPCC regulation in 2002 to be more consistent with the CWA. Formerly, the geographic scope of the rule extended to navigable waters of the United States and adjoining shorelines. The current rule reflects the full geographic scope of EPA's authority to include a discharge:

- Into or upon the waters of the contiguous zone;
- In connection with activities under the Outer Continental Shelf Lands Act or the Deepwater Port Act of 1974; or
- That may affect natural resources belonging to, appertaining to, or under the exclusive management authority of the United States (including resources under the Magnuson Fishery Conservation and Management Act).

The rule's scope includes discharges harmful not only to the public health and welfare, but also to the environment through the protection of natural resources. Such protection would apply to resources under the Magnuson Fishery Conservation and Management Act, a statute that establishes exclusive U.S. management authority over all fishing within the exclusive economic zone (inner boundary coterminous with the seaward boundary of each coastal state), and all anadromous fish throughout their migratory range except when in a foreign nation's waters, and all fish on the continental shelf.

2.6.4 Definition of "Navigable Waters"

Section 112.2 provides the SPCC rule's definition of "navigable waters." This definition has been revised on several occasions, most recently in 2008. The current definition of navigable waters for the SPCC rule is the definition promulgated by EPA in 1973 (73 FR 71941, November 26 2008).

EPA and the U.S. Army Corps of Engineers have issued guidance on implementing Supreme Court decisions that affect CWA jurisdiction over navigable waters.[48] The guidance is found in *Appendix H*.[49]

§112.2

"*Navigable waters*" of the United States means "navigable waters" as defined in section 502(7) of the FWPCA, and includes:

(1) All navigable waters of the United States, as defined in judicial decisions prior to the passage of the 1972 Amendments to the FWPCA (Pub. L. 92-500), and tributaries of such waters;

(2) Interstate waters;

(3) Intrastate lakes, rivers, and streams which are utilized by interstate travelers for recreational or other purposes; and

(4) Intrastate lakes, rivers, and streams from which fish or shellfish are taken and sold in interstate commerce.

Note: The above text is an excerpt of the SPCC rule. Refer to 40 CFR part 112 for the full text of the rule.

[48] In *Solid* Waste *Agency of Northern Cook County* v. *United States Army Corps of Engineers,* 531 U.S. 159 (2001) (referred to as "SWANCC"*)*, the Supreme Court held that the agencies cannot assert CWA jurisdiction over intrastate non-navigable isolated waters based solely on use or potential use by migratory birds, presence of habitat.

2.7 Storage Capacity Thresholds

The SPCC rule applies to certain facilities that have more than 42,000 U.S. gallons of completely buried oil storage capacity or more than 1,320 U.S. gallons of aggregate aboveground oil storage capacity, provided it meets the other applicable criteria set forth in §112.1.

Under §112.1(b)(1) through (4), the rule is applicable to eligible facilities that have oil in aboveground containers; completely buried tanks; containers that are used for standby storage, for seasonal storage, or for temporary storage, or are not otherwise "permanently closed;" and "bunkered tanks" or "partially buried tanks" or containers in a vault. Containers include not only oil storage tanks, but also mobile or portable containers such as drums and totes, and oil-filled equipment such as electrical equipment (e.g., transformers, circuit breakers), manufacturing flow-through process equipment, and operational equipment. Under §112.1(d)(2) the rule limits the applicability to facilities with oil capacity above specific threshold amounts.

Once a facility is subject to the rule, *all* aboveground containers and completely buried tanks are subject to the rule requirements (unless these containers are otherwise exempt from the regulation). For example, a facility could have 10,000 U.S. gallons of aggregate aboveground storage capacity in tanks and oil-filled equipment of 55 U.S. gallons or more, and a completely buried tank of 10,000 U.S. gallons that is not subject to all of the technical requirements of 40 CFR part 280 or a state program approved under part 281 (and therefore not exempt). Since the aboveground storage capacity exceeds 1,320 U.S. gallons, all of the tanks and oil-filled equipment, including the buried tank, are subject to the SPCC rule.

2.7.1 Storage Capacity Calculation

Sections 112.1(d)(2)(i) and (ii) clarify which containers are included and excluded when calculating total storage capacity at a facility in determining whether it exceeds the volume limits in the rule. The container capacities to count and not count are discussed below.

2.7.2 Definition of Storage Capacity

Under the SPCC rule, if a container has the requisite capacity, it does not matter whether the container is actually filled to that capacity. The storage capacity of a container is defined as the shell capacity of the container.

In the consolidated cases *Rapanos v. United States* and *Carabell v. United States* (referred to simply as "Rapanos") the Supreme Court made two substantive decisions that indicated that a water is a "water of the US" either where the water is:

- "relatively permanent, standing, or continuously flowing bodies of water" connected to traditional navigable waters, and to "wetlands with a continuous surface connection to" such relatively permanent waters; or
- "either alone or in combination with similarly situated lands in the region, significantly affect the chemical, physical and biological integrity of other covered waters more readily understood as navigable' (i.e. whether there is a significant nexus with navigable waters).

[49] Guidance on SWANCC is available in a joint memorandum between EPA and the U.S. Army Corps of Engineers (Corps) (see 68 FR 1995, January 15, 2003). Guidance on Rapanos is provided in *Appendix H*.

If a certain portion of a container is incapable of storing oil because of its integral design (e.g., mechanical equipment or other interior components take up space), then the shell capacity of the container is reduced to the volume the container could hold (67 FR 47081, July 17, 2002). Generally, the shell capacity is the rated design capacity rather than the working/operational capacity.

§112.2

Storage capacity of a container means the shell capacity of the container.

Note: The above text is an excerpt of the SPCC rule. See 40 CFR part 112 for the full text of the rule.

Industry standards for certain field-erected and shop-fabricated aboveground vertical storage tanks define the storage capacity of the tank as the physical capacity of the shell to contain liquid, and if present, the capacity can be limited by overflow openings that restrict the liquid level so that the container cannot hold liquid above that point. Thus, for tanks that have floating roofs or internal floating pans where overflow openings or slots are present in the shell, the freeboard volume above the overflow openings or slots is not included in the tank's shell capacity. However, if an existing tank with overflow ports or vents is modified by covering the overflow ports or vents, the container storage capacity reverts to the original shell capacity (see Tank Re-rating section below).

Any modification to the existing port or vent must be performed in accordance with applicable industry standards. Additionally, this container alteration will require a technical amendment to the SPCC Plan certified by a PE in accordance with §112.5. The PE will ensure that the alteration was performed in accordance with applicable industry standards, original design specifications and good engineering practice. Note that many aboveground field erected tanks have cone-down bottoms (the volume of the cone bottom can be significant for larger tanks). This volume is included in the overall storage capacity of the tank.

Devices such as hydraulic overfill valves or high level alarms or procedures, such as operational controls, are not a means of limiting the capacity of a storage container because these systems or procedures can fail or an owner/operator can easily override or remove the controls, increasing the storage capacity of the container.

FYI - What capacities to count and not to count

Do count the following oil containers' capacities:

- All containers of oil with a capacity of 55 U.S. gallons or greater (unless otherwise exempt).

Do not count the following exempt oil containers' capacities:

- Permanently closed containers
- Motive power containers
- Hot-mix asphalt (HMA) or any HMA containers
- Single-family residential heating oil containers
- Pesticide application equipment and related mix containers
- Milk and milk product containers and associated piping and appurtenances
- Completely buried tanks that are subject to all of the technical requirements of 40 CFR part 280 or a State program approved under 40 CFR part 281
- Underground oil storage tanks including below-grade vaulted tanks, that supply emergency diesel generators at nuclear power stations
- Containers used exclusively for wastewater treatment

2.7.3 Tank Re-rating

Shell capacity is used as the measure of storage capacity, unless physical changes are made to the design shell capacity in a permanent, non-reversible, manner that reduces the capacity of the container to contain liquid. An owner or operator may reduce the capacity of a tank by changing the shell dimensions (e.g., by removing shell plate sections, or installing a double bottom in accordance with applicable industry standards). When the alteration is an action such as the installation of a double bottom or new floor to the container, the integral design of the container has changed, and may result in a reduction in shell container capacity.

EPA also considers overflow ports or vents installed in accordance with industry standards as an acceptable method of reducing the shell capacity of container.[50] These properly engineered alterations can be considered permanent when the alteration to the container is performed in accordance with applicable industry standards. However, even when a shell penetration is completed in accordance with industry standards, this does not re-rate the storage capacity of the tank to a lower capacity if the owner or operator overrides the alteration.

[50] To be considered as overflow ports, the size and number of overflow ports shall be based on filling the tank (i.e., fill rate) without increasing the liquid level above the bottom of the overflow port.

When an overflow nozzle is equipped with a pipe and a valve, and the valve is then closed, the container's capacity reverts to the original shell capacity.[51] If an overfill opening is closed at a later date, this constitutes a change in service and as such, per API 653, the tank's suitability for service must be reevaluated and the original capacity of the tank to the top of the shell becomes the measure of storage capacity. This and similar actions that reverse or effectively override the prior alteration used to change the original shell capacity of the container may change the shell capacity again and require an amendment to the SPCC Plan.

Any container alteration will require a technical amendment to the SPCC Plan certified by a PE in accordance with §112.5. The PE will ensure that the alteration was performed in accordance with applicable industry standards and in consideration of original design specifications. Relevant industry standards include American Petroleum Institute (API) Standard 653 "Tank Inspection, Repairs, Alteration, and Reconstruction" (API-653). This standard includes requirements for adding shell penetrations (which may be used to reduce container capacity) such as shell penetration (i.e., nozzle) for overflow. Tank alterations which change the original shell capacity may affect secondary containment capacity necessary to comply with SPCC requirements and FRP applicability and requirements under 40 CFR part 112 subpart D. Thus, changes in container storage capacity may affect FRP requirements for calculating the worst case discharge volume and the amount of resources required to respond to a worst case discharge scenario to comply with the FRP requirements.

Simply drilling a hole in the container, so that the container cannot hold liquid above that point, may not be an appropriate method to re-rate tank capacity when this alteration is not in accordance with applicable industry standards. In this case the original capacity of the container has not changed and remains the measure of storage capacity. Finally, devices (e.g. hydraulic overfill valves and high level alarms) and procedures (e.g. administrative controls) may not be used to limit the capacity of a storage container. For more information on how to evaluate a re-rated tank see *Chapter 7: Inspection, Evaluation, and Testing* (see Section *7.6.1*).

2.8 Exemptions to the Requirements of the SPCC Rule

In addition to the criteria described above, §112.1(d) describes certain types of additional equipment and facilities that are exempt from SPCC rule requirements.

2.8.1 Permanently Closed Containers

Permanently closed containers are exempt from SPCC regulation. Once permanently closed, a container no longer counts toward the total facility storage capacity, nor is it subject to the other requirements under the SPCC rule. The SPCC rule does not require that permanently closed

§112.2

Permanently closed means any container or facility for which (1) All liquid and sludge has been removed from each container and connecting line; and (2) All connecting lines and piping have been disconnected from the container and blanked off, all valves (except ventilation valves) have been closed and locked, and conspicuous signs have been posted on each container stating that it is a permanently closed container and noting the date of closure.

Note: The above text is an excerpt of the SPCC rule. Refer to 40 CFR part 112 for the full text of the rule.

[51] A valve is not recommended unless otherwise required by code.

containers be removed from a facility.

In addition, any container brought on to a facility that has never stored oil is not subject to the SPCC rule, nor is it counted toward the facility capacity until it stores oil. Any other container that at one time stored oil but no longer contains oil or sludge, which is brought on to a facility and meets the definition of permanently closed, is not subject to the SPCC rule nor is it counted toward the facility capacity until it stores oil.

§112.1(d)

Except as provided in paragraph (f) of this section, this part does not apply to: ...

(3) Any offshore oil drilling, production, or workover facility that is subject to the notices and regulations of the Minerals Management Service, as specified in the Memorandum of Understanding between the Secretary of Transportation, the Secretary of the Interior, and the Administrator of EPA, dated November 8, 1993 (Appendix B of this part).

Note: The above text is an excerpt of the SPCC rule. Refer to 40 CFR part 112 for the full text of the rule.

Permanent closure requirements under the SPCC rule are separate and distinct from the closure requirements in regulations promulgated under Subtitle C of the Resource Conservation and Recovery Act (RCRA).[52] These regulations establish the requirements for owners and operators of facilities that use tank systems for storing or treating hazardous waste, and include the requirements for tank system closure and post-closure care (§§264.197 and 265.197). These requirements generally do not apply to an oil production facility. According to the applicability provision in §264.1(b),[53] ''the standards in this part apply to owners and operators of all facilities which treat, store, or dispose of hazardous waste, except as specifically provided otherwise in this part or part 261 of this chapter." In addition, 40 CFR part 261 states that ''Drilling fluids, produced waters, and other wastes associated with the exploration, development, or production of crude oil, natural gas or geothermal energy'' are not hazardous waste (§261.4(b)(5)). Therefore, an oil production facility that does not otherwise treat, store, or dispose of hazardous waste would not have to undergo the expense of permanent closure under Part 264 or 265 of RCRA, based on the management of these wastes (i.e., drilling fluids, produced waters, and other wastes associated with the exploration, development, or production of crude oil) which are exempt from subtitle C regulations.

52 See *Standards for Owners and Operators of Hazardous Waste Treatment, Storage, and Disposal Facilities* at 40 CFR part 264 and *Interim Status Standards for Owners and Operators of Hazardous Waste Treatment, Storage, and Disposal Facilities* at 40 CFR part 265.

53 The applicability provision under §265.1(b) includes similar language that excludes oil production facilities.

Permanently closed containers - Is it really permanent?

The SPCC rule does not include a provision to temporarily close containers to account for seasonal use of tanks or variable economic conditions and production rates at oil production facilities. In order for a container to be exempt from SPCC rule requirements, the container must meet the following criteria for a permanently closed container:

- All liquid and sludge has been removed from each container and connecting line;
- All connecting lines and piping have been disconnected from the container and blanked off,
- All valves (except ventilation valves) have been closed and locked, and
- Conspicuous signs have been posted on each container stating that it is a permanently closed container and noting the date of closure.

A permanently closed container may remain at the facility. However, a facility owner or operator should review state and local requirements, which may require removal of a container when it is taken out service. When a container is removed from the facility, the SPCC Plan must be amended and the technical amendment must be certified.

In the event that a permanently closed container is brought back into use (e.g., to accommodate variations in production rates), the SPCC Plan will need to be amended to reflect the capacity of the permanently closed container if this capacity was previously excluded from the facility total capacity.

2.8.2 Offshore Oil Drilling, Production or Workover Facilities Subject to Minerals Management Service Regulations

Section 112.1(d)(3) excludes offshore oil drilling, production, or workover facilities that are subject to notices and regulations of the Minerals Management Service (MMS). The facilities are regulated by the Department of Interior as specified in the 1994 DOI-DOT-EPA MOU (40 CFR part 112, Appendix B).

The memorandum states that MMS has jurisdiction over facilities, including pipelines, located seaward of the coast line, except for deepwater ports and associated seaward pipelines delegated by Executive Order 12777 to DOT. EPA is responsible for non-transportation-related offshore facilities located landward of the coast line. The term “coast line” is defined as in the Submerged Lands Act (43 U.S.C. 1301(c)) to mean “the line of ordinary low water along that portion of the coast which is in direct contact with the open sea and the line marking the seaward limit of inland waters.”

MMS has been replaced, most recently on October 1, 2011, by the Bureau of Ocean Energy Management

§112.1(d)

Except as provided in paragraph (f) of this section, this part does not apply to: ...

(3) Any offshore oil drilling, production, or workover facility that is subject to the notices and regulations of the Minerals Management Service, as specified in the Memorandum of Understanding between the Secretary of Transportation, the Secretary of the Interior, and the Administrator of EPA, dated November 8, 1993 (Appendix B of this part).

Note: The above text is an excerpt of the SPCC rule. Refer to 40 CFR part 112 for the full text of the rule.

(BOEM) and the Bureau of Safety and Environmental Enforcement (BSEE) as part of a reorganization. BOEM is responsible for managing environmentally and economically responsible development of the nation's offshore resources. Its functions include offshore leasing, resource evaluation, review and administration of oil and gas exploration and development plans, renewable energy development, National Environmental Policy Act (NEPA) analysis and environmental studies.[54] BSEE is responsible for safety and environmental oversight of offshore oil and gas operations, including permitting and inspections, of offshore oil and gas operations. Its functions include the development and enforcement of safety and environmental regulations, permitting offshore exploration, development and production, inspections, offshore regulatory programs, oil spill response and newly formed training and environmental compliance programs.[55]

2.8.3 Underground Storage Tanks

Under §112.1(d)(4), the SPCC rule exempts completely buried storage tanks, as well as connected underground piping, underground ancillary equipment, and containment systems, when such tanks are subject to all of the technical requirements of 40 CFR part 280 or a state program approved under 40 CFR part 281 (also known as the Underground Storage Tank regulations[56]). Although these tanks are exempt from the SPCC requirements, they must still be marked on the facility diagram if the facility is otherwise subject to the SPCC rule (see §112.7(a)(3)).

The regulations at 40 CFR parts 280 and 281 comprise the Underground Storage Tank (UST) Program, which requires owners and operators of new tanks and tanks already in the ground to prevent, detect, and clean up releases. The SPCC rule only recognizes a subset of tanks covered by the UST Program regulations. Specifically, the UST Program defines an underground storage tank as a tank and any underground piping that has at least 10 percent of its combined volume underground. However, under the SPCC rule, only *completely* buried tanks subject to all of the technical UST program requirements are exempt from the rule. Any tanks that are not completely buried are considered aboveground storage tanks and subject to the SPCC rule.

> **§112.2**
>
> *Completely buried tank* means any container completely below grade and covered with earth, sand, gravel, asphalt, or other material. Containers in vaults, bunkered tanks, or partially buried tanks are considered aboveground storage containers for purposes of this part.
>
> Note: The above text is an excerpt of the SPCC rule. Refer to 40 CFR part 112 for the full text of the rule.

The following completely buried tanks are either excluded from the definition of UST or are exempt from the UST regulations at 40 CFR part 280 (and therefore may be subject to the SPCC rule if they contain oil):

- Tanks with a capacity of 110 U.S. gallons or less;

54 See www.boem.gov

55 See www.bsee.gov

56 See Technical Standards and Corrective Action Requirements for Owners and Operators of Underground Storage Tanks (UST) at 40 CFR part 280 and Approval of State Underground Storage Tank Programs at 40 CFR part 281.

- Farm or residential tanks with a capacity of 1,100 U.S. gallons or less used for storing motor fuel for non-commercial purposes;
- Tanks used for storing heating oil for consumptive use on the premises where stored;
- Tanks storing non-petroleum oils, such as animal fat or vegetable oil;
- Tanks on or above the floor of underground areas (e.g., basements or tunnels);
- Septic tanks and systems for collecting storm water and wastewater;
- Flow-through process tanks;
- Emergency spill and overfill tanks that are expeditiously emptied after use;
- Surface impoundments, pits, ponds, or lagoons;
- Any UST system holding RCRA hazardous waste;
- Any equipment or machinery that contains regulated substances for operational purposes such as hydraulic lift tanks and electrical equipment tanks;
- Liquid trap or associated gathering lines directly related to oil or gas production or gathering operations;
- Pipeline facilities regulated under the Natural Gas Pipeline Safety Act of 1968, the Hazardous Liquid Pipeline Safety Act of 1979, or intrastate pipelines regulated under state laws comparable to the provisions of above laws;[57] and
- Any UST system that contains *de minimis* concentration of regulated substances.

The following are examples of deferrals from the UST regulations (and therefore may be subject to the SPCC rule):

- Wastewater treatment tank systems;
- Any UST systems containing radioactive materials that are regulated under the Atomic Energy Act of 1954;

[57] Although exempt from UST regulations, pipeline facilities regulated under the Natural Gas Pipeline Safety Act of 1968, the Hazardous Liquid Pipeline Safety Act of 1979, or intrastate pipelines regulated under state laws comparable to the provisions of above laws do not generally come within EPA's jurisdiction and are not generally regulated under the SPCC rule. See *Section 2.5*.

- Airport hydrant fuel distribution systems; and
- UST systems with field-constructed tanks.

Note that, at an otherwise SPCC-regulated facility, any transfer to or from completely buried storage tanks is regulated because it is a potential source of discharge of oil into navigable waters or adjoining shorelines. Because a loading/unloading rack, or other transfer area, associated with a UST is not typically part of the UST system, it is not subject to all of the technical requirements of 40 CFR part 280 or 281. Therefore, such a loading/unloading rack is regulated under the SPCC regulations in the same manner as any other transfer equipment or transfer activity located at an otherwise SPCC-regulated facility (73 FR 74250, December 5, 2008).

Additional and/or more stringent requirements may exist in a state-approved program under 40 CFR part 281 and they may also impact SPCC applicability. For example, a state may choose to regulate a UST used for storing heating oil for consumptive use on the premises where stored. Thus, under the state program the UST is subject to all the technical requirements of a 40 CFR part 281 program and therefore exempt from the SPCC rule. Inspectors should consider any state UST program approved under 40 CFR part 281 when addressing applicability issues associated with completely buried tanks.

A list of states with approved 281 UST programs, and their respective *Federal Register* notices, is available at http://www.epa.gov/oust/fsstates.htm.

2.8.4 Underground Emergency Diesel Generator Tanks at Nuclear Power Stations

Under §112.1(d)(4), the SPCC rule exempts underground oil storage tanks deferred under 40 CFR part 280, as originally promulgated, that supply emergency diesel generators at nuclear power generation facilities licensed by Nuclear Regulatory Commission (NRC) and that meet the NRC design criteria and quality assurance criteria.

This exemption includes both tanks that are completely buried and tanks that are below-grade and vaulted. In order to be eligible for the exemption, the below-grade vaulted tank must meet the definition of an underground storage tank in 40 CFR 280. An underground storage tank or UST is defined in 40 CFR part 280 as ‘‘any one or combination of tanks… the volume of which is 10 percent or more beneath the surface of the ground.’’ A storage tank situated in an underground area (such as a basement, cellar, mineworking, drift, shaft, or tunnel) is excluded from the definition when the storage tank is situated upon or above the surface of the floor. Therefore, a below-grade vaulted tank located in a space that an inspector can routinely walk into and view all sides of the tank would not be eligible for the exemption from SPCC requirements.

§112.1(d)

Except as provided in paragraph (f) of this section, this part does not apply to: ...

(4) ...any underground oil storage tanks including below-grade vaulted tanks, deferred under 40 CFR part 280, as originally promulgated, that supply emergency diesel generators at a nuclear power generation facility licensed by the Nuclear Regulatory Commission, provided that such a tank is subject to any Nuclear Regulatory Commission provision regarding design and quality criteria, including, but not limited to, 10 CFR part 50. Such emergency generator tanks must be marked on the facility diagram as provided in §112.7(a)(3), if the facility is otherwise subject to this part.

Note: The above text is an excerpt of the SPCC rule. Refer to 40 CFR part 112 for the full text of the rule.

Under the NRC regulations, a nuclear power generation facility must meet certain design criteria to ensure that the plant will be operated in a manner protective of the public's health and safety (such as 10 CFR part 50, Appendix A). These NRC design criteria cover the design, fabrication, installation, testing and operation of structures, systems, and components important to safety and are considered to be similar to the measures required under the SPCC regulation for completely buried tanks, which include corrosion protection of buried tanks (§112.8(c)(4)) and of buried piping (§112.8(d)(1)), and inspection and testing of buried piping (§112.8(d)(4)).

Although these tanks are exempt from the SPCC requirements, they must still be marked on the facility diagram if the facility is otherwise subject to the SPCC rule (§112.7(a)(3)).

2.8.5 Wastewater Treatment Facilities

The wastewater treatment exemption, outlined in §112.1(d)(6), excludes from the SPCC requirements facilities or parts of facilities that are used exclusively for wastewater treatment, and are not used to meet 40 CFR part 112 requirements. Do not count the capacity of these exempt containers when calculating facility aggregate capacity.

> **§112.1(d)**
>
> Except as provided in paragraph (f) of this section, this part does not apply to: ...
>
> (6) Any facility or part thereof used exclusively for wastewater treatment and not used to satisfy any requirement of this part. The production, recovery, or recycling of oil is not wastewater treatment for purposes of this paragraph.
>
> Note: The above text is an excerpt of the SPCC rule. Refer to 40 CFR part 112 for the full text of the rule.

Many of the wastewater treatment facilities or parts thereof are subject to the National Pollutant Discharge Elimination System (NPDES) or state-equivalent permitting requirements that involve operating and maintaining the facility to prevent discharges. The NPDES or state-equivalent process ensures review and approval of the facility's plans and specifications; operation/maintenance manuals and procedures; and Storm Water Pollution Prevention Plans, which may include Best Management Practice (BMP) Plans (67 FR 47068, July 17, 2002).

For the purposes of the exemption, the production, recovery, or recycling of oil is not considered wastewater treatment. These activities generally lack NPDES or state-equivalent permits and thus lack the protections that such permits provide. The goal of an oil production, oil recovery, or oil recycling facility is to maximize the production or recovery of oil, while eliminating impurities in the oil, including water, whereas the goal of a wastewater treatment facility is to purify water (67 FR 47068-69, July 17, 2002). Additionally, produced water is not considered wastewater and is therefore not eligible for this exemption. However, produced water containers used exclusively for wastewater treatment at dry gas production facilities are eligible for the wastewater treatment exemption (see 69 FR 29728, May 25, 2004).

The exemption also does not apply to a wastewater treatment facility (or part of that facility) that is used to store oil. In those instances, the oil storage capacity must be counted as part of the total facility storage capacity (see 67 FR 47068, July 17, 2002). For example, if there is a 1,000-gallon storage container that contains oil removed from an exempt oil/water separator and a 500-gallon storage container for an emergency

generator, the total aboveground storage capacity for the facility would be 1,500 U.S. gallons, and the facility may potentially be regulated by the SPCC rule.

A wastewater treatment facility (or parts of that facility) used to meet a 40 CFR part 112 requirement, including an oil/water separator used to meet any SPCC requirement, is not exempt. Oil/water separators used to meet SPCC requirements include those used to satisfy the secondary containment requirements of §112.7(c), §112.7(h)(1), and/or §§112.8(c)(2) or 112.8(c)(11). Although not exempt, oil/water separators used to satisfy secondary containment requirements of the rule do not count toward storage capacity. For more information, refer to *Chapter 5: Oil/Water Separators*, which clarifies how the SPCC rule applies to oil/water separators and produced water at dry gas production facilities.

2.8.6 Motive Power

A motive power container is defined as any onboard bulk storage container used primarily to power the movement of a motor vehicle, or ancillary onboard oil-filled operational equipment (§112.2). Section 112.1(d)(7) exempts motive power containers from regulation under the SPCC rule. Section 112.1(d)(2)(ii) excludes the capacity of these containers from facility capacity calculations. Motive power containers include the fuel tanks that are used primarily to power a motor vehicle's movement and the on-board hydraulic and lubrication containers used for ancillary functions of the motor vehicle.

§112.1(d)

Except as provided in paragraph (f) of this section, this part does not apply to: ...

(7) Any "motive power container," as defined in §112.2. The transfer of fuel or other oil into a motive power container at an otherwise regulated facility is not eligible for this exemption.

Note: The above text is an excerpt of the SPCC rule. Refer to 40 CFR part 112 for the full text of the rule.

§112.2

Motive power container means any onboard bulk storage container used primarily to power the movement of a motor vehicle, or ancillary onboard oil-filled operational equipment. An onboard bulk storage container which is used to store or transfer oil for further distribution is not a motive power container. The definition of motive power container does not include oil drilling or workover equipment, including rigs.

Note: The above text is an excerpt of the SPCC rule. Refer to 40 CFR part 112 for the full text of the rule.

Bulk Storage Container Used for Propulsion

Containers on motor vehicles that provide the vehicle with a means of propulsion are considered motive power containers. Examples of motor vehicles which have containers used to individually provide their own means of propulsion from location to location within a facility or between facilities include:

- Aircraft,
- Cherry pickers,
- Self-propelled cranes,
- Self-propelled aviation ground service equipment vehicles,

- Self-propelled heavy vehicles (e.g., used in forestry, agricultural, mining, excavation and construction applications), and
- Locomotives.

Ancillary On-Board Equipment

Ancillary on-board equipment includes hydraulic and lubrication operational oil-filled containers used for other ancillary functions of a motor vehicle. It also includes motor vehicle bulk storage containers that serve a non-operational purpose in addition to the propulsion of the motor vehicle: for example, a bulk storage container that supplies fuel to an engine that provides the propulsion for that motor vehicle, as well as its auxiliary units and functions (i.e., heaters, air conditioning units, and electrical power generation, etc.).

Exclusions from the Motive Power Container Definition

The exemption does not include non-self-propelled stationary or towed equipment, such as towed ground service equipment or any type of oil-powered generator (gensets; see *Section 2.10.6*). The following are examples of equipment that are *not* motive power containers because they do not include containers used for propulsion:

- Towed aviation ground service equipment,
- Non-self-propelled construction/cargo cranes,
- Non-self-propelled (forestry, agricultural, mining, excavation or construction) equipment,
- Oil-powered generators,
- Fire pumps, and
- Compressors.

An onboard bulk storage container used to store or transfer oil for further distribution is also not a motive power container. An onboard bulk storage container that supplies oil for the movement of a vehicle or operation of onboard equipment, and at the same time is used for the distribution or storage of this oil is not eligible for the exemption. This situation includes, for example, a mobile refueler that has an onboard bulk storage container used to distribute fuel to other vehicles on a site and which also draws its engine fuel (for propulsion) from that bulk container.

Oil drilling and workover equipment (including rigs) are not eligible for the motive power container exemption because they are specifically excluded from the definition of a motive power container. Although drilling and workover rigs are not exempt, other types of motive power containers located at drilling or workover facilities (i.e., trucks, automobiles, bulldozers, seismic exploration vehicles, or other earth-moving equipment) are exempt.

Oil Transfers to Motive Power Containers

Regardless of the exemption for motive power containers, oil transfer activities occurring within an SPCC-regulated facility are regulated. An example of such an activity would be the transfer of oil from an oil storage container via a dispenser to a motive power container. This transfer activity is subject to the general secondary containment requirements of §112.7(c). See *Chapter 4: Secondary Containment and Impracticability* for more information on secondary containment requirements.

2.8.7 Hot-mix Asphalt and Hot-mix Asphalt Containers

Hot-mix asphalt (HMA) is a blend of asphalt cement (AC) and aggregate material, such as stone, sand, gravel or ground rubber tires, which is formed into final paving products for use on roads and parking lots. Under §112.1(d)(8), the SPCC rule exempts HMA and HMA containers. Section 112.1(d)(2)(ii) excludes the capacity of HMA and HMA containers from facility capacity calculations.

> **§112.1(d)**
>
> Except as provided in paragraph (f) of this section, this part does not apply to: ...
>
> (8) Hot-mix asphalt, or any hot-mix asphalt container.
>
> Note: The above text is an excerpt of the SPCC rule. Refer to 40 CFR part 112 for the full text of the rule.

This exemption from SPCC regulation is based on the fact that HMA is unlikely to flow as a result of the entrained aggregate, such that there would be very few circumstances, if any, in which a discharge of HMA would have the potential to reach navigable waters or adjoining shorelines.

However, asphalt cement, as well as asphalt derivatives such as asphalt cutbacks and emulsions remain subject to the SPCC rule (see the discussion in *Section 2.2.4*).

2.8.8 Heating Oil Containers at Single-family Residences

Many regulated facilities, including farms, military installations, colleges and universities, may include single family residence heating oil tanks within the geographical confines of the facility. Residential heating oil containers used to store oil for the sole purpose of heating single-family residences (including a residence at a farm) are exempt from the SPCC rule under §112.1(d)(9). They are also excluded from facility storage capacity calculations in Section 112.1(d)(2). This exemption applies to aboveground as well as completely buried heating oil tanks at single-family residences. Heating oil tanks used for on-site consumptive use of oil are also exempt from underground storage tanks requirements under 40 CFR part 280.

> **§112.1(d)**
>
> Except as provided in paragraph (f) of this section, this part does not apply to: ...
>
> (9) Any container for heating oil used solely at a single-family residence.
>
> Note: The above text is an excerpt of the SPCC rule. Refer to 40 CFR part 112 for the full text of the rule.

A single-family residence is a household that has direct ownership of the oil stored in the heating oil container. In addition, if a commercial facility (for example, a university) includes a single-family residence on the premises, then any heating oil container associated solely with this residence is exempt from SPCC rule applicability.

However, the SPCC requirements apply to oil containers used to heat other non-residential buildings within a facility, because the exemption covers only residential heating oil containers at single-family residences. Owners and operators of commercial facilities, such as a multi-family structure (e.g. condominiums and apartment complexes) remain subject to the SPCC rule. These facilities generally store much larger volumes of oil, and if there is a reasonable expectation of an oil discharge to navigable waters or adjoining shorelines, then oil spill prevention measures need to be addressed in an SPCC Plan.

2.8.9 Pesticide Application Equipment and Related Mix Containers

Pesticide formulations may include petroleum- or vegetable-based oils in concentrated formulations or may contain crop oil or adjuvant oil in the mix formulations added just prior to application. Pesticide application equipment and related mix containers are exempt from the SPCC rule, under §112.1(d)(10) and the facility capacity calculations in §112.1(d)(2)(ii).

Pesticide application equipment includes ground boom applicators, airblast sprayers, and specialty aircraft containers/equipment that are used to apply measured quantities of pesticides to crops and/or soil. Related mix containers are those used to mix pesticides with water and, as needed, adjuvant oils, just prior to loading into the application equipment.

§112.1(d)

Except as provided in paragraph (f) of this section, this part does not apply to:...

(10) Any pesticide application equipment or related mix containers.

Note: The above text is an excerpt of the SPCC rule. Refer to 40 CFR part 112 for the full text of the rule.

Containers (55 U.S. gallons or greater in capacity) storing oil prior to blending it with the pesticide, and containers used to store any pesticides after they have been mixed with oil, are considered bulk storage containers and are regulated as such under the SPCC rule.

EPA adopted this exemption because this type of pesticide use and related mix containers are already subject to regulation under the Federal Insecticide, Fungicide, and Rodenticide Act (FIFRA), as codified in *Standards for Pesticide Containment Structures* in 40 CFR part 165, to assure the safe use (including discharge), reuse, storage, and disposal of pesticide containers.

2.8.10 Intra-Facility Gathering Lines Subject to Department of Transportation (DOT) Requirements

Intra-facility gathering lines (i.e. gathering lines found within the confines of a non-transportation-related facility) may be under the jurisdiction of both EPA and DOT as described in *Section 2.5.8*. However, certain DOT requirements for pipelines are considered to be similar in scope to SPCC regulations. Therefore, intra-facility gathering lines that are subject to DOT regulatory requirements at 49 CFR part 192 (*Transportation*

of Natural and Other Gas by Pipeline) or 195 (*Transportation of Hazardous Liquids by Pipeline*) are exempt from the SPCC rule under §112.1(d)(11). If intra-facility gathering lines are not subject to DOT regulatory requirements (i.e., gathering lines that by statute are subject to DOT jurisdiction, yet are not subject to the DOT regulations) they remain subject to 40 CFR part 112. Other equipment and piping at an oil production facility (such as flowlines) remain subject to SPCC requirements.

EPA considers intra-facility gathering lines subject to EPA's jurisdiction if they are located within the boundaries of an otherwise regulated SPCC facility. *Appendix H* includes drawings that show EPA's regulatory jurisdiction at complexes, including an example of an oil production facility with gathering lines.[58]

> **§112.1(d)**
>
> Except as provided in paragraph (f) of this section, this part does not apply to: …
>
> (11) Intra-facility gathering lines subject to the regulatory requirements of 49 CFR part 192 or 195, except that such a line's location must be identified and marked as "exempt" on the facility diagram as provided in §112.7(a)(3), if the facility is otherwise subject to this part.
>
> Note: The above text is an excerpt of the SPCC rule. Refer to 40 CFR part 112 for the full text of the rule.

The exemption requires owners or operators of a facility to identify and mark as "exempt" the location of exempt piping on the facility diagram. This requirement will assist both facility and EPA personnel in defining the boundaries of EPA and DOT jurisdiction and provide response personnel with information used to identify hazards during a spill response activity. More information about facility diagram requirements is provided in *Chapter 6: Facility Diagram and Description*.

Issues related to intra-facility gathering lines and their SPCC requirements are covered in detail in *Chapter 3: Environmental Equivalence* (*Section 3.3.5*) and *Chapter 4: Secondary Containment and Impracticability* (*Section 4.2.2*).

2.8.11 Milk and Milk Product Containers

Milk and milk product containers and associated piping and appurtenances are exempt from the SPCC requirements under §112.1(d)(12) and excluded from facility capacity calculations in §112.1(d)(2)(ii). Butter, cheese, and dry milk containers are a few examples of milk product containers subject to the exemption.

> **§112.1(d)**
>
> Except as provided in paragraph (f) of this section, this part does not apply to: …
>
> (12) Any milk and milk product container and associated piping and appurtenances.
>
> Note: The above text is an excerpt of the SPCC rule. Refer to 40 CFR part 112 for the full text of the rule.

All milk and/or milk product transfer and processing activities are included in the scope of this exemption from the SPCC rule. For more information on the final rule exempting milk and milk product containers see 76 FR 21652, April 18, 2011.

[58] See EPA Jurisdiction at Complexes.

2.8.12 Summary of Exemptions

Table 2-3 provides a summary of containers and equipment, as described in the preceding sections, which are exempt from the requirements of the SPCC rule and therefore excluded from a facility's oil storage capacity calculation.

Table 2-3: Summary of oil storage capacity calculation as described in §112.1(d)(2)(i) and (ii).[59]

Included	Excluded
Capacity of containers (e.g., bulk storage containers, oil-filled equipment, mobile/portable containers) with a capacity of 55 U.S. gallons or greater (unless otherwise exempt)	Capacity of a container that is permanently closed
	Capacity of a motive power container
	Capacity of hot-mix asphalt or any hot-mix asphalt container
	Capacity of a container for heating oil used solely at a single-family residence
	Capacity of pesticide application equipment and related mix containers
	Capacity of any milk and milk product container and associated piping and appurtenances
	Capacity of any completely buried tank and associated underground piping, ancillary equipment, and containment systems subject to all technical requirements of 40 CFR part 280 or a state-approved program under 40 CFR part 281
	Capacity of any underground oil storage tanks including below-grade vaulted tanks, that supply emergency diesel generators at a nuclear power generation facility licensed by the Nuclear Regulatory Commission and subject to any Nuclear Regulatory Commission provision regarding design and quality criteria, including, but not limited to, 10 CFR part 50

2.9 Determination of Applicability by the Regional Administrator

Section 112.1(f) allows the Regional Administrator (RA) to require the preparation and implementation of an SPCC Plan or applicable part from the owner or operator of an otherwise exempted facility that is subject to EPA jurisdiction under §311(j) of the CWA. This provision is designed to address gaps in other regulatory regimes that may be remedied by requiring a facility to have an SPCC Plan. For example, a facility may be exempt from the SPCC

§112.1(f)

Notwithstanding paragraph (d) of this section, the Regional Administrator may require that the owner or operator of any facility subject jurisdiction of EPA under section 311(j) of the CWA prepare and implement an SPCC Plan, or any applicable part, to carry out the purposes of the CWA.

Note: The above text is an excerpt of the SPCC rule. Refer to 40 CFR part 112 for the full text of the rule.

[59] Also exclude the capacity of containers used exclusively for wastewater treatment as described in §112.1(d)(6)

rule because its storage capacity is below the regulatory threshold, but the facility may have been the cause of repeated discharges as described in §112.1(b).

Factors the RA may consider in making a determination to require that a facility prepare an SPCC Plan include, but are not limited to, the physical characteristics of the facility; the presence of secondary containment; the discharge history of the facility; and the proximity of the facility to sensitive environmental areas such as wetlands, parks, or wildlife refuges. The RA might require either an entire Plan or a partial Plan addressing a specific rule requirement like secondary containment, for example, to prevent future discharges.

Sections 112.1(f)(1) through (5) describe the process for an RA to determine applicability. The process includes specific deadlines for both the RA and the facility owner or operator, as well as requirements for the type of information and delivery method. *Table 2-4* lists the deadlines and responsibilities of the RA and the facility owner or operator to appeal the RA determination that requires preparing an SPCC Plan.

Table 2-4: Process for an RA determination of SPCC applicability and appeals.

Deadline	Responsibility
Determination	
As needed.	*Regional Administrator* (RA) makes a preliminary determination. RA must provide a written notice to the owner/operator stating the reasons why an SPCC Plan or applicable part of a Plan is needed. (§112.1(f)(1))
Within *30 days* of receipt of notice of a potential need to prepare an SPCC Plan (following preliminary determination)	*Owner/operator* must provide information and data and may consult with EPA about the need to prepare an SPCC Plan, or applicable part. (§112.1(f)(2))
Within *30 days* of receipt of data	RA makes a final determination regarding whether the owner/operator is required to prepare and implement an SPCC Plan, or applicable part. (§112.1(f)(3))
Within *6 months* of final determination that facility needs a Plan	*Owner/operator* must prepare the Plan, or applicable part. (§112.1(f)(4))
Within *1 year* of final determination that facility needs a Plan	*Owner/operator* must implement the Plan, or applicable part. (§112.1(f)(4))
Appeals	
Within *30 days* of receipt of final determination that facility needs a Plan	*Owner/operator* may appeal final determination to the Administrator of EPA (and send a copy to the RA). (§112.1(f)(5))
Within *60 days* of receiving the appeal or additional information submitted by owner/operator	*The Administrator* renders a decision on the appeal. (§112.1(f)(5))

The EPA inspector plays an important role in assisting the RA in determining applicability. For example, an inspector may initially alert the RA of the need for an otherwise exempt facility to have an SPCC Plan. This may result from an inspection prompted by a citizen complaint or state referral, an oil spill, or awareness of

other conditions that warrant closer examination. Following an RA determination of the need for an SPCC Plan, the EPA inspector may perform a targeted inspection of the subject facility to verify compliance with SPCC requirements.

2.10 SPCC Applicability for Different Types of Containers

2.10.1 Bulk Storage Container

A bulk storage container, as defined in §112.2, with a capacity of 55 U.S. gallons or greater, must follow specific requirements, as described under §§112.8(c), 112.9(c), and 112.12(c) for onshore facilities. Examples of these requirements include, but are not limited to, secondary containment and fail-safe engineering (such as high level alarms), inspections, and testing.

2.10.2 Double-walled or Vaulted Tanks or Containers

Double-walled tanks are essentially a tank within another tank, equipped with an interstitial (i.e., annular) space and constructed in accordance with industry standards. The inner tank serves as the primary oil storage container while the outer tank serves as secondary containment. The outer tank of a double-walled tank may provide adequate secondary containment for discharges resulting from leaks or ruptures of the entire capacity of the inner storage tank.

The term ‘‘vaulted tank’’ has been used to describe both double-walled tanks (especially those with a concrete outer shell) and tanks inside underground vaults, rooms, or crawl spaces. Both double-walled tanks and vaulted tanks are bulk storage containers under the SPCC rule. For more information on how double-walled tanks comply with the secondary containment and inspection requirements of the SPCC rule see *Chapter 4: Secondary Containment and Impracticability* and *Chapter 7: Inspection, Evaluation, and Testing*.

2.10.3 Oil-filled Equipment

The definition of bulk storage container in §112.2 specifically excludes oil-filled electrical, operating, and manufacturing equipment (“oil-filled equipment”). Therefore, oil-filled equipment is not subject to the bulk storage container requirements in §§112.8(c), 112.9(c), and 112.12(c). However, oil-filled equipment must meet the general requirements of §112.7. See generally 67 FR 47054-47055, July 17, 2002.

While the integrity testing requirements of §§112.8(c)(6) and 112.12(c)(6) are only applicable to bulk storage containers, EPA believes it is good engineering practice to have some form of visual inspection or monitoring for this oil-filled equipment to prevent discharges as described in §112.1(b). For example, it is a challenge to comply with security requirements under

§112.2

Bulk storage container means any container used to store oil. These containers are used for purposes including, but not limited to, the storage of oil prior to use, while being used, or prior to further distribution in commerce. ***Oil-filled electrical, operating, or manufacturing equipment is not a bulk storage container.***

Note: The above text is an excerpt of the SPCC rule. Refer to 40 CFR part 112 for the full text of the rule. ***Emphasis added.***

§112.7(g) and countermeasures for discharge discovery under §112.7(a)(3)(iv)) without some form of inspection or monitoring program. Additionally, inspection and/or monitoring should be part of an effective contingency plan when secondary containment for this equipment is impracticable.

2.10.4 Oil-filled Operational Equipment

"Oil-filled operational equipment" is defined under §112.2 as equipment that includes an oil storage container (or multiple containers) in which the oil is present solely to support the function of the apparatus or the device. Oil-filled operational equipment is not considered a bulk storage container, and does not include oil-filled manufacturing equipment (flow-through process).

Examples of oil-filled operational equipment include, but are not limited to, hydraulic systems, lubricating systems (e.g., those for pumps, compressors and other rotating equipment, including pumpjack lubrication systems), gear boxes, machining coolant systems, heat transfer systems, transformers, circuit breakers, electrical switches, wind turbines, and other systems containing oil solely to enable the operation of the device (§112.2). When piping is intrinsic to the oil-filled operational equipment in a closed loop system, i.e., inherent to the equipment and used solely to facilitate operation of the device (e.g., for lubrication), then EPA considers the piping to be a component of the oil-filled operational equipment. However, piping not intrinsic to the operational equipment (e.g., flowlines, transfer piping or piping associated with a process) is not considered to be part of the oil-filled operational equipment.

§112.2

Oil-filled operational equipment means equipment that includes an oil storage container (or multiple containers) in which the oil is present solely to support the function of the apparatus or the device. Oil-filled operational equipment is not considered a bulk storage container, and does not include oil-filled manufacturing equipment (flow-through process). Examples of oil-filled operational equipment include, but are not limited to, hydraulic systems, lubricating systems (e.g., those for pumps, compressors and other rotating equipment, including pumpjack lubrication systems), gear boxes, machining coolant systems, heat transfer systems, transformers, circuit breakers, electrical switches, and other systems containing oil solely to enable the operation of the device.

Note: The above text is an excerpt of the SPCC rule. Refer to 40 CFR part 112 for the full text of the rule.

Under §112.7(k), the owner or operator of a facility with oil-filled operational equipment that meets specific qualification criteria may choose to implement the alternate requirements for qualified oil-filled operational equipment in lieu of the general secondary containment required in §112.7(c). *Chapter 4: Secondary Containment and Impracticability* (*Section 4.2.1*) provides more information about this option.

2.10.5 Oil-filled Manufacturing Equipment

Oil-filled manufacturing equipment is distinct from bulk storage containers in its purpose. Oil-filled manufacturing equipment stores oil only as an ancillary element of performing a mechanical or chemical operation to create or modify an intermediate or finished product. Examples of oil-filled manufacturing equipment may include reaction vessels, fermentors, high pressure vessels, mixing tanks, dryers, heat exchangers, and distillation columns. Under the SPCC rule, flow-through process vessels are generally

considered oil-filled manufacturing equipment since they are not intended to store oil.[60] Additionally, there may be oil-filled operational equipment (e.g., a hydraulic unit) at this type of facility to support the manufacturing equipment (see generally 67 FR 47080, July 17. 2002). The PE reviewing and certifying the SPCC Plan should be familiar with processes taking place at the facility and should therefore determine whether a given process vessel is considered a bulk storage container or oil-filled manufacturing equipment.

In cases where a container is used for the static storage of oil within a manufacturing or processing area, the PE may determine that the container is in fact a bulk storage container. Examples of oil storage within manufacturing areas include:

- Storing an intermediate product for an extended period of time in a continuous or batch process;
- Storing a raw product prior to use in a continuous or batch process; and
- Storing a final product after a continuous or batch process.

Storage tanks and containers located at the beginning or end of a process and used to store feedstock or finished products generally are considered bulk storage containers. In cases where oil storage is incidental to the manufacturing activity or process (e.g., where it is being transformed in a flow-through process vessel) the Plan preparer may determine that the container is part of the manufacturing equipment.

Oil-filled manufacturing equipment is inherently more complicated than oil-filled operational equipment because it typically involves a flow-through process and is commonly interconnected through piping. Oil-filled manufacturing equipment is subject to the general SPCC requirements under §112.7, including a demonstration of impracticability under §112.7(d) if the SPCC Plan does not provide for general secondary containment as required by §112.7(c). (71 FR 77266, December 26, 2006).

2.10.6 Oil-powered Generators ("Gen-sets")

Oil powered generators are commonly referred to as "gen-sets." Gen-sets are a combination of oil-filled operational equipment and a bulk oil storage container. The oil that is consumed to generate electricity is not inherent to the device and is stored in a bulk storage container, which requires transfers of oil because oil is consumed in order to generate electricity. Therefore, although gen-sets include oil-filled operational equipment, such as the lubrication oil reservoir, gen-sets, as a whole unit, do not meet the definition of oil-filled operational equipment.

Newer designs of gen-sets provide for a double-walled tank for the bulk oil storage container. This type of design may meet the sized and general containment requirements of the SPCC rule (112.8(c)(2), 112.8(c)(11) and 112.7(c)) for the bulk storage container, however, this does not address secondary containment for the oil-

[60] The U.S. Occupational Safety and Health Administration (OSHA)'s Process Safety Management (PSM) regulation (29 CFR 1910.119) considers a single process "any group of vessels which are interconnected and separate vessels which are located such that a highly hazardous chemical could be involved in a potential release." The PSM definition of process includes storage tanks, while the SPCC rule considers storage tanks as bulk storage containers and not manufacturing equipment.

filled operational equipment on the gen-set. To address the oil-filled operational equipment on these gen-sets, the facility owner/operator can provide secondary containment for the typical failure mode and most likely quantity of oil that would be discharged from the oil-filled operational equipment on the gen-set (in accordance with §112.7(c)) or provide alternative measures as provided for qualified oil-filled operational equipment in §112.7(k).

When it is impracticable to provide appropriate secondary containment for gen-sets (for either the bulk storage containers or oil-filled operational equipment of the gen-set), a PE can make a determination of impracticability in accordance with §112.7(d); and can develop a contingency plan following the provisions of 40 CFR part 109 and provide a written commitment of manpower, equipment, and materials to expeditiously control and remove any quantity of oil discharged that may be harmful.

2.10.7 Bulk Storage Containers at Tank Battery, Separation and Treating Areas

An oil production facility typically includes, at a minimum, a wellhead, a tank battery, and flowlines connecting the wellhead to the tank battery and in some cases, the tank battery to an injection wellhead. The tank battery includes separation and treating equipment, a crude oil or condensate container (oil stock tank), drums of oil-based products and typically a produced water container, which receives both oil and produced water from the separator. Bulk storage containers at oil production facilities must be:

- Compatible with the materials stored and condition of storage;
- Provided with secondary containment sized for the largest single container and sufficient freeboard to contain precipitation for those containers at the tank battery, separation and treating facility installations;
- Visually inspected periodically and upon a regular schedule for deterioration and maintenance needs, including the foundation and support; and
- Engineered in accordance with good engineering practice to prevent discharges by:
    1. Ensuring adequate container capacity to assure that a container will not overfill if a pumper/gauger is delayed in making regularly scheduled rounds;
    2. Providing overflow equalizing lines between containers so that a full container can overflow to an adjacent container;
    3. Providing adequate vacuum protection to prevent container collapse during a pipeline run or other transfer of oil from the container; or
    4. Providing high level sensors to generate and transmit an alarm signal to the computer where the facility is subject to a computer production control system.

Alternative measures are provided for flow through process vessels and produced water containers in lieu of the secondary containment and inspection requirements of §§112.9(c)(2) and (3) as described below.

Flow-through Process Vessels

Separation and treating installations at an oil production facility typically include equipment whose primary purpose is to separate the well fluid into its marketable or waste fractions (e.g., oil, gas, produced water, and solids), and to treat the crude oil as needed for further storage and shipping. Flow-through process vessels, such as horizontal or vertical separation vessels (e.g., heater-treater, separator, gun barrel, free-water knockout, etc.), have the primary purpose of separating the oil from other fractions (water and/or gas) and sending the fluid streams to the appropriate container.

Flow-through process vessels at separation and treatment installations are bulk storage containers and count toward the facility aggregate oil storage capacity. They are also subject to general secondary containment under §112.7(c) and the bulk storage container requirements of §112.9(c). The facility owner or operator must either provide sized secondary containment for flow-through process vessels in accordance with §112.9(c)(2) and inspect them following §112.9(c)(3) or comply with the general secondary containment under §112.7(c) and alternative measures provided in §112.9(c)(5). More information about the secondary containment requirements and the alternative compliance provision for flow-through process vessels can be found in *Chapter 4: Secondary Containment and Impracticability* (*Section 4.8.1*).

Produced Water Containers

Produced water containers are bulk storage containers typically located within the tank battery. Produced water containers are part of the process that separates the oil from other fractions (water and/or gas).

Oil discharges to navigable waters or adjoining shorelines from an oil/water mixture in a produced water container may cause harm. Such mixtures[61] are regulated as oil under the SPCC rule. Therefore, the capacity of produced water containers counts toward the facility aggregate oil storage capacity. Produced water containers are subject to general secondary containment under §112.7(c) and the bulk storage container requirements in §112.9(c). The facility owner or operator must either provide sized secondary containment for produced water containers in accordance with §112.9(c)(2) and inspect them following §112.9(c)(3) or comply with general secondary containment under §112.7(c) and alternative measures provided in §112.9(c)(6).

> **§112.2**
>
> *Produced water container* means a storage container at an oil production facility used to store the produced water after initial oil/water separation, and prior to reinjection, beneficial reuse, discharge, or transfer for disposal.
>
> Note: The above text is an excerpt of the SPCC rule. Refer to 40 CFR part 112 for the full text of the rule.

The alternative measures require that the facility owner or operator conduct visual inspections; perform maintenance and corrective action; and remove, or stabilize and remediate, oil discharges. Additionally a PE must describe in the SPCC Plan and certify that a practice is established that is designed to remove the amount of free-phase oil from the produced water container on a scheduled and routine basis. More information about

[61] Refers to mixtures in the produced water container.

the secondary containment requirements and the alternative compliance provision for produced water containers can be found in *Chapter 4: Secondary Containment and Impracticability* (*Section 4.8.2*).

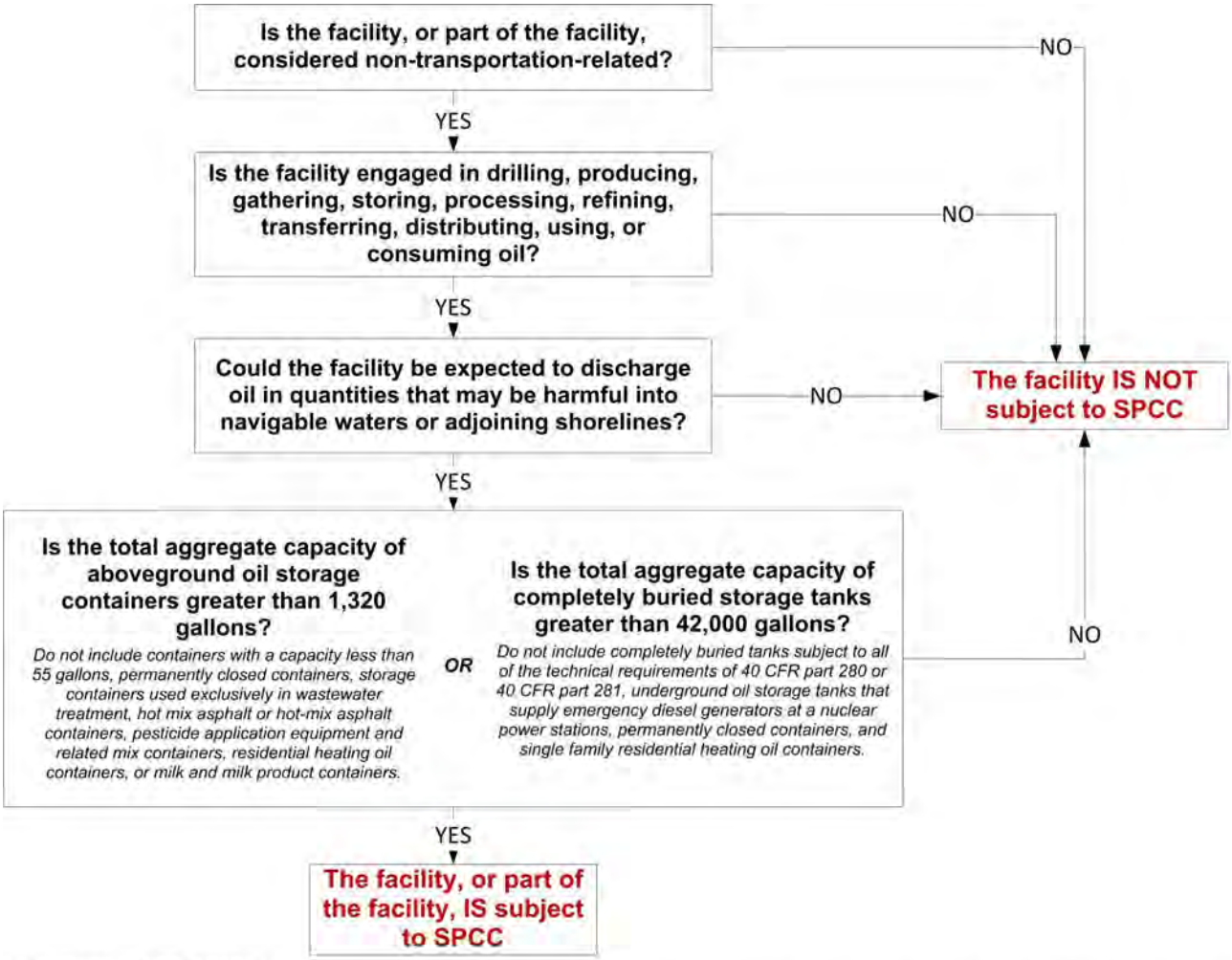
2.11 Determination of Applicability of Facility Response Plans

A portion of the SPCC-regulated community may also be required to prepare a Facility Response Plan (FRP). According to §112.20, an owner or operator of a facility that has the potential to cause substantial harm to the environment in the event of a discharge into or on navigable waters or adjoining shorelines must prepare and submit an FRP. *Owners or operators of SPCC facilities must document whether they meet the FRP applicability criteria (40 CFR 112 Appendix C Section 3.0).* Owners/operators may refer to the "Flowchart of Criteria for Substantial Harm," Attachment C-I to Appendix C of 40 CFR part 112, to determine whether they need to prepare an FRP. The owner or operator must document his/her determination of whether the facility has the potential to cause substantial harm by completing the Attachment C-II form, "Certification of the Applicability of the Substantial Harm Criteria," and maintaining the certification at the facility. Attachments C-I and C-II are included in Appendix C of 40 CFR part 112 (also see *Appendix H* of this guidance).

2.12 Role of the EPA Inspector

The EPA inspector is responsible for gathering information and data to determine compliance with SPCC requirements for those facilities that are regulated by the SPCC rule. During an SPCC inspection, EPA inspectors will check that the measures described in the SPCC Plan are implemented at the facility and will fully document all observations and other pertinent information. The EPA inspector will check that the Plan is kept at the facility if it is attended more than four hours per day. The *Summary of Applicability Flowchart* and *Applicability Assessment Worksheet*, provided as *Figure 2-8* and *Figure 2-9*, are two quick references provided for convenience to aid inspectors in assessing whether a facility is subject to the SPCC rule.

Figure 2-8: Summary of applicability flowchart.



Definitions (40 CFR 112.2)

Completely buried tank: Any container completely below grade and covered with earth, sand, gravel, asphalt, or other material. Containers in vaults, bunkered tanks, or partially buried tanks are considered aboveground storage containers for purposes of this part.

Complex: A facility possessing a combination of transportation-related and non-transportation-related components that is subject to the jurisdiction of more than one Federal agency under section 311(j) of the CWA.

Facility: Any mobile or fixed, onshore or offshore building, structure, installation, equipment, pipe or pipeline (other than a vessel or a public vessel) used in oil well drilling operations, oil production, oil refining, oil storage, oil gathering, oil processing, oil transfer, oil distribution, and oil waste treatment, or in which oil is used, as described in Appendix A to the SPCC rule. The boundaries of a facility depend on several site-specific factors, including, but not limited to, the ownership or operation of buildings, structures, and equipment on the same site and the types of activity at the site.

Permanently closed: Any container or facility for which: (1) All liquid and sludge has been removed from each container and connecting line; and (2) All connecting lines and piping have been disconnected from the container and blanked off, all valves (except for ventilation valves) have been closed and locked, and conspicuous signs have been posted on each container stating that it is a permanently closed container and noting the date of closure.

Storage capacity: Shell capacity of the container.

The intent of this flowchart is to show the general principles of applicability. Inspectors should always consult the *Code of Federal Regulations* and applicable MOUs.

Figure 2-9: Applicability assessment worksheet.

1 Is the facility or part of the facility considered non-transportation-related and engaged in one of the following activities? (Refer to *Section 2.3* of this chapter.)

Drilling, producing, gathering, storing, processing, refining, transferring, distributing, using, or consuming oil.

☐ Yes. Go to question 2.

☐ No. The facility is not subject to the SPCC rule.

2 Could the facility reasonably be expected to discharge oil in quantities that may be harmful into navigable waters or adjoining shorelines? (Refer to *Section 2.6* of this chapter.)

Note: This determination must be based solely upon consideration of the geographical and location aspects of the facility (such as proximity to navigable waters or adjoining shorelines, land contour, drainage, etc.) and must exclude consideration of manmade features such as dikes, equipment or other structures, which may serve to restrain, hinder, contain, or otherwise prevent a discharge.

☐ Yes. Go to question 3a.

☐ No. The facility is not subject to the SPCC rule.

3a Is the total aggregate capacity of aboveground oil storage containers greater than 1,320 U.S. gallons? (Refer to *Sections 2.7* and *2.8* of this chapter.)

Note: Exclude containers less than 55 gallons, permanently closed containers, motive power containers, storage containers used exclusively in wastewater treatment, hot-mix asphalt containers, pesticide application equipment and related mix containers, single-family residential heating oil containers, milk and milk product containers, and underground storage tanks that supply emergency diesel generators at nuclear power stations.

☐ Yes. The facility is subject to the SPCC rule.

☐ No. Go to question 3b.

3b Is the total aggregate capacity of completely buried storage tanks greater than 42,000 U.S. gallons? (Refer to *Sections 2.7* and *2.8* of this chapter.)

Note: Do not include completely buried tanks subject to all technical requirements of 40 CFR part 280 or 281, permanently closed containers, single-family residential heating oil containers, or underground storage tanks that supply emergency diesel generators at nuclear power stations.

☐ Yes. The facility is subject to the SPCC rule.

☐ No. The facility is not subject to the SPCC rule.

Chapter 3 Environmental Equivalence

3.1 Introduction

The environmental equivalence provision, contained in §112.7(a)(2), allows for deviations from specific requirements of the SPCC rule, as long as the alternative measures provide equivalent environmental protection. The environmental equivalence provision is a key mechanism of the performance-based SPCC rule. This flexibility enables owners and operators of facilities to achieve environmental protection in a manner that fits the facility's unique circumstances. It also allows owners and operators to adopt more protective industry practices and technologies for their facilities as they become available.

The facility owner or operator is responsible for the selection, documentation in the SPCC Plan, and implementation in the field of SPCC measures, including any environmentally equivalent measures. However, a Professional Engineer (PE), when certifying a Plan as per §112.3(d) or §112.6(b)(4), must verify that the Plan (and any alternative methods) are in accordance with good engineering practice, including consideration of applicable industry standards. These alternative methods must also provide environmental protection equivalent to the provisions described in the SPCC rule. Because the expertise of a trained professional is important in making site-specific equivalence determinations, owners or operators of qualified facilities (those meeting the criteria in §112.3(g)) who choose to self-certify their SPCC Plans in lieu of PE-certification cannot take advantage of the flexibility allowed by the environmental equivalence provision, unless the alternative methods have been reviewed and certified in writing by a PE (§112.6(b)(3)(i)).[62]

In the SPCC context, equivalent environmental protection means an equal level of protection of navigable waters and adjoining shorelines from oil pollution. This level of protection can be achieved in various ways, but a facility may not rely solely on measures that are required by other sections of the rule (e.g., implementing secondary containment) to provide environmentally equivalent protection. While environmental equivalence need not be a mathematical equivalence, it must achieve the same desired outcome, though not necessarily through the same mode of operation (see 67 FR 47095, July 17, 2002).

The reason for deviating from a requirement of the SPCC rule, as well as a detailed description of the alternate method and how equivalent environmental protection will be achieved, must be stated in the SPCC Plan, as required in §112.7(a)(2). Possible rationales for a deviation include the owner or operator's ability to show that the particular requirement is inappropriate for the facility because of good engineering practice considerations or other reasons, and that the owner/operator can achieve equivalent environmental protection in an alternate manner. Thus, a requirement that may be essential for a facility storing gasoline may be less appropriate for a facility storing hot asphalt cement, due to differences in the properties and behavior of the

[62] For each alternative measure allowed under §112.7(a)(2), a qualified facility's Plan must be accompanied by a written statement that states the reason for nonconformance and describes the alternative method and how it provides equivalent environmental protection in accordance with §112.7(a)(2) (see §112.6(b)(3)(i)).

two products, and the facility owner or operator may be able to implement equivalent environmental protection through an alternate technology (see 67 FR 47094, 47095, July 17, 2002).

As mentioned above, a PE must review the selection of environmentally equivalent measures and certify them as being consistent with good engineering practice (§112.3(d) or §112.6(b)(4)). The selection of alternative measures may be based on various considerations, such as safety, cost, geographical constraints, the appropriateness of a particular requirement based on site-specific considerations, or other factors consistent with engineering principles. See *Section 3.4.1* for a discussion on considering costs when choosing environmentally equivalent measures.

Alternative measures, however, cannot rely solely on measures that are already required by other parts of the rule because this would allow for approaches that provide a lesser degree of protection overall. For instance, as EPA noted in a May 2004 letter to the Petroleum Marketers Association of America (PMAA), the presence of sized secondary containment for bulk storage containers, which is required under §112.8(c) and other relevant parts of the SPCC rule, does not provide, by itself, an environmentally equivalent alternative to performing integrity testing of bulk storage containers.[63] Secondary containment reduces the risk of a discharge from primary containment (the container or tank) to navigable waters or adjoining shorelines and can increase the effectiveness of another prevention or control measure. However, it does not serve the purpose of integrity testing, which is to identify potential leaks or failure of the container before a discharge occurs.

The remainder of this chapter is organized as follows:

- ***Section 3.2*** summarizes substantive SPCC requirements subject to the environmental equivalence provision.
- ***Section 3.3*** clarifies certain policy areas and provides examples of deviations based on the implementation of environmentally equivalent alternatives.
- ***Section 3.4*** describes the role of the EPA inspector in reviewing deviations based on environmental equivalence.

3.2 Substantive Requirements Subject to the Environmental Equivalence Provision

Section 112.7(a)(2) of the SPCC rule allows deviations for most *technical* elements of the rule (§§112.7 through 112.12), with the exception of the secondary containment requirements of §§112.7(c) and 112.7(h)(1), and in relevant paragraphs of §§112.8, 112.9, 112.10, and 112.12. *Chapter 4: Secondary Containment and Impracticability* discusses these secondary containment requirements in detail.

[63] See EPA letter to Daniel Gilligan of PMAA, available in *Appendix H* of this guidance.

§112.7(a)(2)

Comply with all applicable requirements listed in this part. Except as provided in §112.6, your Plan may deviate from the requirements in paragraphs (g), (h)(2) and (3), and (i) of this section and the requirements in subparts B and C of this part, except the secondary containment requirements in paragraphs (c) and (h)(1) of this section, and §§112.8(c)(2), 112.8(c)(11), 112.9(c)(2), 112.9(d)(3), 112.10(c), 112.12(c)(2), and 112.12(c)(11), where applicable to a specific facility, ***if you provide equivalent environmental protection by some other means of spill prevention, control, or countermeasure***. Where your Plan does not conform to the applicable requirements in paragraphs (g), (h)(2) and (3), and (i) of this section, or the requirements of subparts B and C of this part, except the secondary containment requirements in paragraphs (c) and (h)(1) of this section, and §§112.8(c)(2), 112.8(c)(11), 112.9(c)(2), 112.10(c), 112.12(c)(2), and 112.12(c)(11) you ***must state the reasons for nonconformance in your Plan and describe in detail alternate methods and how you will achieve equivalent environmental protection***. If the Regional Administrator determines that the measures described in your Plan do not provide equivalent environmental protection, he may require that you amend your Plan, following the procedures in §112.4(d) and (e).

Note: The above text is an excerpt of the SPCC rule. Refer to 40 CFR part 112 for the full text of the rule. ***Emphasis Added.***

Along with secondary containment requirements, the SPCC Plan cannot deviate from:

- Administrative provisions of the rule, such as applicability thresholds, exemptions, definitions and procedures for developing, reviewing and implementing a Plan (§§112.1 through 112.5);
- Rule requirements for Tier I qualified facilities (§112.6(a));
- Alternate measures for secondary containment based on impracticability (§112.7(d)) or for oil-filled operational equipment that meet the criteria in §112.7(k);
- Recordkeeping requirements (§112.7(e))—the SPCC rule already provides flexibility for recordkeeping that allows records of inspections and tests be kept under usual and customary business practices;
- Personnel training (§112.7(f)); and
- A discussion of conformance with any applicable, more stringent state rules (§112.7(j)).

Table 3-1 through *Table 3-3* list the SPCC requirements eligible for consideration for environmental equivalence.

Table 3-1: Requirements eligible for environmental equivalence at all facilities.

Provision	Section(s)
Security	112.7(g)
Loading and unloading racks	112.7(h)(2) and 112.7(h)(3)
Brittle fracture evaluation	112.7(i)

Table 3-2: Requirements eligible for environmental equivalence at onshore facilities (excluding oil production).

Provision	Section(s)	
	Petroleum Oils and Non-Petroleum Oils	Animal Fats and Vegetable Oils
Section introduction[64]	112.8(a)	112.12(a)
Facility drainage/undiked areas	112.8(b)	112.12(b)
Type of bulk storage container	112.8(c)(1)	112.12(c)(1)
Drainage of diked areas	112.8(c)(3)	112.12(c)(3)
Corrosion protection of buried storage tanks	112.8(c)(4) and 112.8(c)(5)	112.12(c)(4) and 112.12(c)(5)
Integrity testing and/or container inspection	112.8(c)(6)	112.12(c)(6)
Monitoring internal heating coils	112.8(c)(7)	112.12(c)(7)
Engineering of bulk container installation (overfill prevention)	112.8(c)(8)	112.12(c)(8)
Monitoring effluent treatment facilities	112.8(c)(9)	112.12(c)(9)
Correction of discharges and removal of oil in diked areas	112.8(c)(10)	112.12(c)(10)
Piping	112.8(d)	112.12(d)

[64] This is an administrative provision to indicate that both the general requirements of §112.7 and the requirements for onshore facilities in either §§112.8 or 112.12 apply. When meeting the general requirements of §112.7, environmental equivalence applies only to the §§112.7(g), (h)(2), (h)(3), and (i) provisions as described in §112.7(a)(2). The availability of environmental equivalence for §112.8(a) and 112.12(a) does not change how environmental equivalence applies in §112.7.

Table 3-3: Requirements eligible for environmental equivalence at onshore and offshore oil production, drilling, and workover facilities.

Facility Type/Provision	Section(s)[65]
Onshore oil production facilities	
Section introduction	112.9(a)
Facility drainage	112.9(b)
Type of bulk storage container	112.9(c)(1)
Container inspection	112.9(c)(3)
Engineering of bulk container installation (overfill prevention)	112.9(c)(4)
Alternative measures for flow-through process vessels	112.9(c)(5)
Alternative measures for produced water containers	112.9(c)(6)
Monitoring disposal facilities	112.9(d)(2)
Piping	112.9(d)(1) and 112.9(d)(4)
Onshore oil drilling and workover facilities	
Section introduction	112.10(a)
Facility drainage (rig position)	112.10(b)
Blowout prevention and well control system	112.10(d)
Offshore oil drilling, production, or workover facilities	
Drainage, container, blowout prevention, and piping requirements	112.11(a) through 112.11(p)

3.3 Policy Issues Addressed by Environmental Equivalence

This section provides additional guidance on environmentally equivalent measures for specific requirements about which the regulated community has raised questions. The examples discussed below are meant to clarify *selected* rule provisions and to illustrate how deviations based on environmentally equivalent alternatives may be implemented; other circumstances not discussed here may also be addressed through the use of environmentally equivalent measures. The examples in this section address environmental equivalence as it relates to specific major rule provisions, including:

[65] Sections 112.9(a), 112.10(a) and 112.11(a) are administrative provisions to indicate that both the general requirements of §112.7 and the requirements for facilities in §112.9, 112.10 or 112.11 apply. When meeting the general requirements of §112.7, environmental equivalence applies only to the §§112.7(g), (h)(2), (h)(3), and (i) provisions as described in §112.7(a)(2). The availability of environmental equivalence for §§112.9(a), 112.10(a) and 112.11(a) does not change how environmental equivalence applies in §112.7.

- Facility Drainage (*Section 3.3.1*);
- Corrosion Protection and Leak Testing of Completely Buried Metallic Storage Tanks (*Section 3.3.2*);
- Overfill Prevention (*Section 3.3.3*) ;
- Facility Transfer Operations, Pumping, and Facility Process Requirements (*Section 3.3.4*);
- Flowline/Intra-Facility Gathering Line Maintenance Program (*Section 3.3.5*);
- Security (Excluding Oil Production Facilities)(*Section 3.3.6*);
- Integrity Testing and Inspection Requirements for Bulk Storage Containers at Onshore Facilities (*Section 3.3.7*); and
- Alternative Measures for Containers at Oil Production Facilities (*Section 3.3.8*).

3.3.1 Facility Drainage

Section 112.8(b) describes facility drainage provisions for onshore facilities that handle petroleum oils and non-petroleum oils other than animal fats and/or vegetable oils. Section 112.12(b) provides the corresponding requirements for facilities that handle animal fats and/or vegetable oils. The description of the design capacity of facility drainage systems is also addressed under §§112.7(a)(3) and 112.7(b).

The objective of these requirements is to provide design specifications for drainage systems used as a means of secondary containment to prevent oil from escaping the facility and becoming a discharge as described in §112.1(b). Note that the secondary containment requirements themselves are not subject to the environmental equivalence provision as described in 112.7(a)(2); deviations from secondary containment requirements must instead be based on an impracticability determination (see *Chapter 4: Secondary Containment and Impracticability*).

Diked Storage Area Provisions

Sections 112.8(b)(1) and (b)(2) (and §112.12(b)(1) and (b)(2)) specify requirements for the design of drainage systems for dikes used as a means of secondary containment. Under §112.8(b)(1) and (b)(2) (and §112.12(b)(1) and (b)(2)), the SPCC regulation requires that when the facility owner/operator uses valves to drain a dike or berm, the valves must be of manual, open-and-closed design and not a flapper design, unless the facility drainage system is equipped to control oil discharges. The facility owner or operator, and the PE certifying a Plan, may consider alternative technologies specifically engineered to prevent oil from escaping the facility containment and drainage control system, while normally allowing drainage of uncontaminated water. For example, certain valves are engineered to automatically shut off upon detecting oil. Material included within the device expands upon contact with oil, effectively plugging the drainage system. The valve is not actuated per se, but rather the device plugs the drainage system upon contact with oil. These types of systems have been

installed at electrical substations, for example, to drain uncontaminated rainwater under normal conditions, while also preventing oil from escaping the containment system in the event of a discharge from transformers or other oil-filled electrical equipment. When implemented and maintained properly, such systems may provide environmental protection equivalent to using a manually operated valve and visually monitoring discharge from dikes.

To be most effective, however, EPA recommends that the systems have a fail-safe design to automatically prevent any oil from escaping the containment area in the event of a system malfunction. The PE certifying the Plan should verify the adequacy of the system to prevent oil discharges to navigable waters or adjoining shorelines, considering factors such as the type of oil and its compatibility with the system selected, the amount of precipitation, maintenance requirements, flow paths, and proximity to navigable waters. The SPCC Plan should also describe procedures for maintaining these systems and verifying their effectiveness by routine inspections and inspections following heavy rain events to ensure that they are operational. See *Chapter 4: Secondary Containment and Impracticability* for more details on secondary containment requirements.

Undiked Storage Area Provisions

Sections 112.8(b)(3) and (b)(4) (and §112.12(b)(3) and (b)(4)) specify performance requirements for systems used to drain undiked areas with the potential for a discharge. These provisions apply only when the facility owner/operator chooses to use a facility drainage system to meet general secondary containment requirements under §112.7(c) or a more specific containment requirement under §§112.7(h)(1), 112.8(c)(2) or 112.12(c)(2). Where the facility drainage cannot be engineered as described in §112.8(b)(3), the SPCC rule requires that the facility owner/operator equip the final discharge points of all ditches within the facility with a diversion system that would, in the event of a discharge, retain the oil at the facility as described in §112.8(b)(4). Requirements in §112.8(b)(5) pertain specifically to engineering multiple treatment units for these drainage systems.

For parts of a facility that could be involved in a discharge and where secondary containment requirements are met through the use of a drainage system rather than a dike or berm, the SPCC rule generally requires facility drainage to flow into a system (e.g., a pond, lagoon, or catchment basin) designed to retain the oil or return it to the facility. For example, an oil/water separator may be used as part of the containment system; however, an environmental equivalent deviation for drainage controls for the separator must be provided.

Other measures that are based on good engineering practice may be implemented to achieve the drainage control objective, subject to PE review and certification. For example, directing undiked facility drainage into an impoundment system located within a neighboring facility may be considered equivalent to keeping it within the facility's confines (as required in §112.8(b)(4)) if the neighboring facility owner has agreed to allow use of the impoundment and as long as the impoundment is designed and managed such that it is capable of handling a potential discharge from both facilities before it becomes a discharge as described in §112.1(b).

Drainage at Oil Production Facilities[66]

Similar deviations from SPCC drainage control requirements are possible for other types of facilities. Section 112.9(b), for example, outlines drainage requirements for tank batteries and separation and treating areas at oil production facilities. They include sealing dike drains or drains of equivalent measures required under §112.7(c)(1) at all times except when draining uncontaminated rainwater. The PE may specify alternative measures (e.g., the technology used at electrical substations as described above that expands upon contact with oil and plugs the drainage system) that would provide equivalent environmental protection by retaining oil within the diked area in the event of a discharge.[67] The Plan must describe the measure in detail and discuss how it provides environmentally equivalent protection when implemented in the field, as required by §112.7(a)(2).

Wherever a facility owner or operator chooses to deviate from the drainage control provisions by using an alternative measure that provides equivalent environmental protection, the SPCC Plan must state the reasons for nonconformance and describe the alternative measure in detail, including how it achieves equivalent environmental protection when implemented (§112.7(a)(2)).

§112.9 (b)

Oil production facility drainage.

(1) At tank batteries and separation and treating areas where there is a reasonable possibility of a discharge as described in §112.1(b), close and seal at all times drains of dikes or drains of equivalent measures required under §112.7(c)(1), except when draining uncontaminated rainwater. Prior to drainage, you must inspect the diked area and take action as provided in §112.8(c)(3)(ii), (iii), and (iv). You must remove accumulated oil on the rainwater and return it to storage or dispose of it in accordance with legally approved methods.

(2) Inspect at regularly scheduled intervals field drainage systems (such as drainage ditches or road ditches), and oil traps, sumps, or skimmers, for an accumulation of oil that may have resulted from any small discharge. You must promptly remove any accumulations of oil.

Note: The above text is an excerpt of the SPCC rule. Refer to 40 CFR part 112 for the full text of the rule.

3.3.2 Corrosion Protection and Leak Testing of Completely Buried Metallic Storage Tanks

Facility owners or operators must protect buried metallic storage tanks (containers) installed on or after January 10, 1974 from corrosion and regularly perform leak test on the tanks. In order to comply with the corrosion protection requirement of §§112.8(c)(4) and 112.12(c)(4), owners and operators of completely buried metallic storage tanks may want to consider the requirements of Subpart B of 40 CFR 280. This regulation includes design, construction and installation requirements for underground storage

§§112.8(c)(4) and 112.12(c)(4)

Protect any completely buried metallic storage tank installed on or after January 10, 1974 from corrosion by coatings or cathodic protection compatible with local soil conditions. You must regularly leak test such completely buried metallic storage tanks.

Note: The above text is an excerpt of the SPCC rule. Refer to 40 CFR part 112 for the full text of the rule.

66 These requirements also apply to wet gas production facilities (where oil condensate is produced).

67 See the above discussion in Diked Storage Area Provisions.

tanks (USTs) including corrosion protection methods for new (see §280.20) and existing (see §280.21) UST systems.

To comply with the leak testing requirements of §§112.8(c)(4) and 112.12(c)(4), a facility owner/operator may consider the requirements of 40 CFR 280.43 which specify release detection methods for petroleum UST systems that include tank tightness testing. Additionally, the Petroleum Equipment Institute (PEI) RP1200 publication "Recommended Practices for the Testing and Verification of Spill, Overfill, Leak Detection and Secondary Containment Equipment at UST Facilities" provides general guidelines for the inspection and testing of leak detection, release prevention and overfill prevention equipment at UST facilities. These methods may be appropriate to meet the SPCC leak testing requirements for buried metallic storage tank.

Tank tightness testing may be accomplished by several methods:[68]

- Pressure testing with inert gas such as nitrogen and checking the tank for loss of pressure. Loss of pressure indicates a leak in the tank.[69] Consult with the tank manufacturer for the recommended test pressure.
- Chemical inoculant testing. A chemical inoculant is added to the product in the tank and sampling ports are installed in the soil around the tank to check for the presence of the chemical (which would indicate a leak in the tank).
- Volumetric testing. Volumetric testing involves measuring very precisely (in milliliters or thousandths of an inch) the change in product level in a tank over time.
- For double-walled tanks, pressure testing or vacuum testing the interstitial space.
- Some automatic tank gauging systems are capable of meeting the regulatory performance requirements for tank tightness testing and can be considered as an equivalent method.

Rather than leak test the completely buried metallic tank, a PE may substitute elements required under 40 CFR part 280 or a state program approved under 40 CFR part 281 to detect a release from the completely buried tank in accordance with the environmental equivalence provision in §112.7(a)(2). For example, a PE may determine that use of a continuous leak detection system in combination with the use of an Automatic Tank Gauge (ATG) is environmentally equivalent to the regular leak testing[70] requirements in §§112.8(c)(4) and 112.12(c)(4).[71]

---

68 The tank must be isolated from piping connections when performing tank tightness tests. Check with state regulatory authorities for state approved leak testing methods. For more information on tank tightness testing see http://www.epa.gov/oust/ustsystm/inventor.htm.

69 CAUTION: Do not use compressed air to pressure test tanks that contain or contained flammable or combustible liquids unless the tank is first purged and cleaned.

70 EPA stated that leak testing ensures the liquid tightness of a container and whether it may discharge oil (67 FR 47118, July 17. 2002).

71 A PE may want to design such an environmentally equivalent measure in accordance with 40 CFR part 280 or a state program

FYI – Cathodic protection of buried tanks

40 CFR 280.20 and 280.21 identify methods for cathodically protecting buried tanks. These methods may be considered when developing corrosion and cathodic protection protocols for completely buried metallic storage tanks subject to the SPCC rule. The following are some examples of codes and standards for protecting metallic tanks from corrosion that may also be considered:

- Steel Tank Institute (STI) "Specification for STI-P3 System of External Corrosion Protection of Underground Steel Storage Tanks"
- Underwriters Laboratories (UL) Standard 1746, "Corrosion Protection Systems for Underground Storage Tanks"
- Underwriters Laboratories of Canada (ULC) CAN4-S603-M85, "Standard for Steel Underground Tanks for Flammable and Combustible Liquids," CAN4-G03.1-M85, "Standard for Galvanic Corrosion Protection Systems for Underground Tanks for Flammable and Combustible Liquids," and CAN4-S631-M84, "Isolating Bushings for Steel Underground Tanks Protected with Coatings and Galvanic Systems"
- National Association of Corrosion Engineers (NACE) Standard RP-02-85, "Control of External Corrosion on Metallic Buried, Partially Buried, or Submerged Liquid Storage Systems," and Underwriters Laboratories Standard 58, "Standard for Steel Underground Tanks for Flammable and Combustible Liquids"

3.3.3 Overfill Prevention

Sections 112.8(c)(8) and 112.12(c)(8) require that each container installation is engineered to avoid discharges during filling activities. The selection of an overfill prevention system should be based on good engineering practice (see §112.7 introductory paragraph), considering methods that are appropriate for the types of activities and circumstances. Regular tests of liquid level sensing devices to ensure proper operation should be conducted on a routine basis.

---

approved under 40 CFR part 281, as a demonstration of good engineering practice.

§112.8(c)(8) and 112.12(c)(8)

Engineer or update each container installation in accordance with good engineering practice to avoid discharges. You must provide at least one of the following devices:

(i) High liquid level alarms with an audible or visual signal at a constantly attended operation or surveillance station. In smaller facilities an audible air vent may suffice.

(ii) High liquid level pump cutoff devices set to stop flow at a predetermined container content level.

(iii) Direct audible or code signal communication between the container gauger and the pumping station.

(iv) A fast response system for determining the liquid level of each bulk storage container such as digital computers, telepulse, or direct vision gauges. If you use this alternative, a person must be present to monitor gauges and the overall filling of bulk storage containers.

(v) You must regularly test liquid level sensing devices to ensure proper operation.

Note: The above text is an excerpt of the SPCC rule. Refer to 40 CFR part 112 for the full text of the rule.

While an audible/visual alarm or fast-response system may be appropriate for a large, stationary storage tank, a simpler overfill prevention procedure may be appropriate for a small container (e.g., relatively small containers that can be readily monitored) when the filling procedure is documented in the SPCC Plan. A procedure for smaller containers that ensures communication between the container gauger and the pumper, is in accordance with §§112.8(c)(8)(iii) and 112.12(c)(8)(iii) and therefore does not require an environmental equivalence determination.

The procedure must be adequate to prevent a discharge by ensuring communication between the container gauger and the pumper. The development of this procedure should consider factors such as the container size; inventory control procedures; filling rate; ability of the person performing the filling operation to continuously monitor product level in the container; reaction time; capacity of the secondary containment and/or catchment basin; and proximity of the tank to floor drains, sumps, and other means through which oil could escape. Personnel should be able to demonstrate an understanding of the procedures and proper field implementation. As part of the description, the Plan preparer may reference other facility documents in the SPCC Plan that discuss relevant established Best Management Practices (BMPs) , pollution prevention training, and/or procedures in more detail, rather than restating this information in the SPCC Plan. Additional supporting documentation should be on-site and available for review during an inspection.

For example, a filling procedure for a small container may involve:

- Verifying that the container has sufficient free capacity (i.e., ullage of the container) for the transfer,
- Visually monitoring the product level throughout the transfer operation, and
- Posting the detailed written procedure described in the SPCC Plan next to the container/fill pipe.

Many facilities have smaller storage containers such as 55-gallon drums, Intermediate Bulk Containers (IBCs) and totes that are never filled at the facility. Since these containers are never filled, the overfill requirements do not apply and there is no need to document environmental equivalence deviations for these containers.

Where a facility owner or operator chooses to deviate from the overfill prevention provisions by using an alternative measure that provides environmentally equivalent protection, the SPCC Plan must state the the reasons for nonconformance and describe the alternative measure in detail, including how it achieves equivalent environmental protection when implemented (§112.7(a)(2)).

FYI – Preventing container overfills

In order to prevent container overfills consider the following:

1) Training individuals involved in the transfer operations;
2) Communicating facility oil transfer procedures to personnel;
3) Ensuring transfer operations are appropriately monitored;
4) Ensuring tank gages and overfill alarms are operational, calibrated and routinely tested;
5) Verifying that the container has sufficient available capacity;
6) Monitoring the product level throughout the operation; and
7) Providing response equipment that is easily accessible from the transfer location

3.3.4 Facility Transfer Operations, Pumping, and Facility Process Requirements

Requirements that apply to valves, appurtenances, piping, and transfer operations at onshore facilities that handle petroleum oils are described in §112.8(d). Similar requirements are described in §112.12(d) for piping at onshore facilities that handle animal fats and/or vegetable oils.

§§112.8(d) and 112.12(d) – Facility-transfer operations, pumping, and facility process.

(1) Provide buried piping that is installed or replaced on or after August 16, 2002, with a protective wrapping and coating. You must also cathodically protect such buried piping installations or otherwise satisfy the corrosion protection standards for piping in part 280 of this chapter or a State program approved under part 281 of this chapter. If a section of buried line is exposed for any reason, you must carefully inspect it for deterioration. If you find corrosion damage, you must undertake additional examination and corrective action as indicated by the magnitude of the damage.

(2) Cap or blank-flange the terminal connection at the transfer point and mark it as to origin when piping is not in service or is in standby service for an extended time.

(3) Properly design pipe support to minimize abrasion and corrosion and allow for expansion and contraction.

(4) Regularly inspect all aboveground valves, piping, and appurtenances. During the inspection you must assess the general condition of items, such as flange joints, expansion joints, valve glands and bodies, catch pans, pipeline supports, locking of valves, and metal surfaces. You must also conduct integrity and leak testing of buried piping at the time of installation, modification, construction, relocation, or replacement.

(5) Warn all vehicles entering the facility to be sure that no vehicle will endanger aboveground piping or other oil transfer operations.

NOTE: The above text is an excerpt of the SPCC rule. Refer to 40 CFR part 112 for the full text of the rule.

These provisions of the SPCC rule require that owners and operators of facilities generally protect buried piping against corrosion; cap or blank-flange the terminal connection of piping that is not in service; design pipe supports to minimize abrasion and corrosion and allow for expansion and contraction; regularly inspect all aboveground valves, piping, and appurtenances; and take corrective action when corrosion damage is found. The rule also requires integrity and leak testing of buried piping at the time of installation, modification, construction, relocation, or replacement. Finally, the rule requires warning all vehicles entering the facility to ensure that they will not endanger aboveground piping (or other oil transfer operations). Types of facility piping addressed by this provision include, but are not limited to:

- Transfer piping to and from bulk storage containers, both aboveground and buried;
- Transfer piping associated with manufacturing equipment, both aboveground and buried; and
- Piping associated with oil-filled operational and manufacturing equipment.

A 1987 EPA study into the causes of oil releases indicates that the operational piping portion of an underground storage tank system is twice as likely as the tank portion to be the source of a discharge.[72] Piping failures are caused equally by poor workmanship, improper installation, corrosion, or other forms of deterioration. The SPCC piping requirements aim to prevent oil discharges from aboveground or buried piping due to corrosion, operational accidents, or collision. Accordingly, equivalent environmental protection may be

[72] "Causes of Release from Underground Storage Tank Systems: Attachments," September 1987, EPA 510-R-92-702.

achieved through alternative measures that reduce or eliminate the risks of corrosion to buried piping or the risk of damage to aboveground piping.

The following sections discuss examples of environmentally equivalent deviations from piping requirements.

Protecting Buried Piping from Corrosion Damage

A PE must certify that the Plan has been prepared in accordance with good engineering practices, including consideration of applicable industry standards. Similarly, an owner/operator self-certifies that the Plan has been prepared in accordance with accepted and sound industry practices. Therefore, the Plan preparer may want to consult a qualified corrosion professional when evaluating the adequacy of cathodic protection and corrosion prevention systems at the facility. If the Plan preparer determines that cathodic protection of buried piping installed on or after August 16, 2002 is not appropriate considering site-specific conditions, facility configuration, and other engineering factors (e.g., where the installation of a corrosion system would accelerate corrosion of existing unprotected equipment), then a PE may specify other measures to assess and ensure the continued fitness-for-service of piping. For example, the owner or operator of a facility could, instead of cathodically protecting underground piping, use double-wall piping combined with an interstitial leak detection system (67 FR 47123, July 17, 2002). Cathodic protection averts discharges by preventing container corrosion, whereas the alternative method of installing a leak detection system and double-wall piping averts discharges by detecting and containing leakage so it may be addressed before it can become a discharge as described in §112.1(b). As with any environmentally equivalent measure, this portion of the Plan must be certified by a PE.

Alternatively, the facility owner or operator may implement a comprehensive monitoring, detection, and preventive maintenance program for piping and appurtenances as an alternative for cathodic protection to detect and address potential discharges. The PE who certifies the Plan or this portion of it, should develop and/or review such a program, which may combine inspection, monitoring and leak testing elements with preventive maintenance, contingency measures, and recordkeeping. Examples of these elements are outlined for piping systems in API Standard 570,[73] "Piping Inspection Code: In-Service Inspection, Rating, Repair, and Alteration of Piping Systems." *Table 3-4* summarizes key elements of an API-570 inspection program when evaluating buried piping that is not cathodically protected (refer to *Chapter 7: Inspection, Evaluation, and Testing* for an overview of API-570). Such a program provides a means of assessing the suitability of piping to contain oil and/or identifying potential failures prior to their occurrence.

[73] API 570 Third Edition 2009

Table 3-4: Summary of inspection and leak testing elements of an API-570 program for unprotected buried piping – additional inspection and testing requirements are specified in API 570 (refer to the full text of API 570 for details).[74]

Inspection and Leak Testing Elements	Summary
Above-grade Visual Surveillance	Inspect the surface of the ground covering the piping for discoloration of the soil, softening of asphalt pavement, formation of pools, bubbling water puddles, and noticeable odor. The inspection should be performed at approximately six month intervals and may be performed by the owner/operator.
Pipe-to-Soil Potential Survey	Conduct pipe-to-soil potential survey along the pipe route to assess corrosion potential. Excavate sites where active corrosion cells are located to determine the extent of corrosion damage.
Pipe Coating Holiday* Survey	Conduct pipe coating holiday survey based on results of other evaluations.
Soil Corrosivity	Perform soil corrosivity evaluation at a five-year interval for piping buried in lengths greater than 100 feet that is not cathodically protected.
Cathodic Protection	Monitor at intervals in accordance with Section 10 of NACE RP0169[75] or API RP651[76] when piping cathodically protected.
External and Internal Inspection Intervals	Determine external condition of buried piping that is not cathodically protected by either pigging or by excavating according to frequency indicated in Table 5 of API-570. Adjust inspection of buried piping based on results of inspections of above-grade portion.
Leak Testing Intervals	Alternatively, or in addition to inspection, perform leak testing with pressure at least 10 percent greater than maximum operating pressure at an interval half the length of intervals in API 570 Table 5 for buried piping that is not cathodically protected. Alternatively, perform temperature-corrected volumetric or pressure test methods, use acoustic emission examination, or addition of tracer fluid.

* "Holiday" means any discontinuity, bare, or thin spot in a painted area.

Where a piping inspection and testing program is used to provide environmental protection equivalent to cathodic protection, a PE will develop and/or review the scope and frequency of the program considering industry standards when available,[77] before certifying that the Plan is in accordance with good engineering practice. Certain elements of a piping inspection and testing program (e.g., frequent leak testing of buried piping) may be emphasized over others based on site-specific factors such as length of piping at the facility or proximity to navigable waters or adjoining shorelines. *Chapter 7: Inspection, Evaluation, and Testing* references

[74] API 570 Third Edition 2009

[75] NACE SP0169-2007 (formerly RP0169), "Control of External Corrosion on Underground or Submerged Metallic Piping Systems", Edition 2007 www.nace.org

[76] API RP 651, "Cathodic Protection of Aboveground Petroleum Storage Tanks", Third Edition, 2007.

[77] See PE attestation in §112.3(d)

industry standards that specifically discuss leak testing, including API Recommended Practice 1110 – Pressure Testing of Steel Pipelines for the Transportation of Gas, Petroleum Gas, Hazardous Liquids, Highly Volatile Liquids or Carbon Dioxide. However, since leak testing only detects existing leaks, rather than preventing them, good engineering practice may suggest that testing occur at a greater frequency than when other prevention systems, such as cathodic protection and coatings, are in place. Accordingly, the PE who certifies the Plan will determine the appropriate frequency of leak tests for buried piping after considering the other prevention and detection measures incorporated into the inspection program.

If alternative measures are used to meet the SPCC corrosion protection requirements for buried piping, §112.7(a)(2) requires that the Plan state the reasons for nonconformance, describe in detail the alternative measures and explain how the alternative measures provide environmental protection equivalent to coating and cathodically protecting new piping. In order to be considered equivalent environmental protection to cathodic protection, a comprehensive inspection and preventive maintenance program needs to be implemented to effectively detect and address piping deterioration before it can result in a discharge as described in §112.1(b). The EPA inspector should verify that the alternative method is described in detail in the SPCC Plan and that the Plan specifies the scope and frequency of tests and inspections and/or refers to the relevant industry standards, as applicable. The EPA inspector should also review records that document these tests and inspections.

Preventing Physical Damage to Aboveground Piping/Transfer Operations

Warnings to vehicles entering the facility may be verbal, posted on signs, or by other appropriate means. The Plan must describe how the warnings will be communicated and should include locations of signs and information provided on the signs. When relying on verbal warnings, the Plan should describe information provided as part of the verbal warnings and the procedure for issuing those warnings including personnel responsible for providing the warnings.

Alternatively, protecting the equipment from the possibility of a collision by installing fencing, barriers, curbing or other physical obstacles may provide equivalent environmental protection. The SPCC Plan must document the method implemented at the facility to prevent physical damage to aboveground piping and transfer operations, and if an alternative method is used, then it must be documented in accordance with §112.7(a)(2).

3.3.5 Flowline/Intra-Facility Gathering Line Maintenance Program

The SPCC rule requires a flowline or intra-facility gathering line maintenance program, according to §112.9(d)(4). A flowline or intra-facility gathering line maintenance program aims to manage oil production operations in a manner that reduces the potential for a discharge from these piping systems. Common causes of such discharges include mechanical damage (e.g., impact, rupture) and corrosion.

§112.9(d)(4)

Prepare and implement a written program of flowline/intra-facility gathering line maintenance. The maintenance program must address your procedures to:

(i) Ensure that flowlines and intra-facility gathering lines and associated valves and equipment are compatible with the type of production fluids, their potential corrosivity, volume, and pressure, and other conditions expected in the operational environment.

(ii) Visually inspect and/or test flowlines and intra-facility gathering lines and associated appurtenances on a periodic and regular schedule for leaks, oil discharges, corrosion, or other conditions that could lead to a discharge as described in §112.1(b). For flowlines and intra-facility gathering lines that are not provided with secondary containment in accordance with §112.7(c), the frequency and type of testing must allow for the implementation of a contingency plan as described under part 109 of this chapter.

(iii) Take corrective action or make repairs to any flowlines and intra-facility gathering lines and associated appurtenances as indicated by regularly scheduled visual inspections, tests, or evidence of a discharge.

(iv) Promptly remove or initiate actions to stabilize and remediate any accumulations of oil discharges associated with flowlines, intra-facility gathering lines, and associated appurtenances.

Note: The above text is an excerpt of the SPCC rule. Refer to 40 CFR part 112 for the full text of the rule.

An effective flowline maintenance program is necessary to detect a discharge in a timely manner so that the oil discharge response operations described in the contingency plan may be implemented effectively. The rule specifically requires a written maintenance program which addresses procedures to:

- **Ensure that flowlines and intra-facility gathering lines and associated valves and equipment are compatible with the type of production fluids, their potential corrosivity, volume, and pressure, and other conditions expected in the operational environment.** This preventative measure is intended to help preserve the integrity of the lines and reduce the potential effects of corrosion or other factors that may lead to a discharge.

- **Visually inspect and/or test flowlines and intra-facility gathering lines and associated appurtenances on a periodic and regular schedule for leaks, oil discharges, corrosion, or other conditions that could lead to a discharge as described in §112.1(b).** This measure is intended to ensure that any discharges, potential problems or conditions related to the flowline/intra-facility gathering lines that could lead to a discharge will be promptly discovered. When flowlines and intra-facility gathering lines have no secondary containment, then the frequency and type of testing must allow for the implementation of a contingency plan as described under 40 CFR part 109. An oil spill contingency plan cannot be effective unless a discharge is discovered in a timely manner so that the oil response operations can be implemented as described in the contingency plan. (See *Chapter 7: Inspection, Evaluation, and Testing* for more information on this inspection requirement.)

- **Take corrective action or make repairs to any flowlines and intra-facility gathering lines and associated appurtenances as indicated by regularly scheduled visual inspections, tests, or evidence of a discharge**. The results of the inspections or tests (as described above) will inform the owner/operator of any corrections or repairs that need to be made. Corrective action is necessary in order to prevent a discharge from occurring, as well as in response to a discharge. This measure is intended to prevent discharges as described in §112.1(b) by ensuring that flowlines and intra-facility gathering lines are well maintained and ensuring prompt corrective actions or repairs in response to conditions found during the inspection/testing of the flowlines and intra-facility gathering lines.

- **Promptly remove or initiate actions to stabilize and remediate any accumulations of oil discharges associated with flowlines, intra-facility gathering lines, and associated appurtenances**. Removing oil-contaminated soil is one method to prevent a discharge from reaching navigable waters or adjoining shorelines. Disposal of oil must be in accordance with applicable Federal, State, and local requirements; under §112.7(a)(3)(v), a facility owner or operator is required to describe the methods of disposal of recovered materials in accordance with applicable legal requirements. For the purposes of this provision, removal of recoverable oil may be combined with physical, chemical, and/or biological treatment methods to address any residual oil. These treatment methods must be consistent with other Federal, state or local requirements as applicable, and must be properly managed to prevent a discharge as described in §112.1(b). "Promptly remove" indicates that the owner or operator of the facility has both the responsibility and flexibility to outline an inspection program under §112.9(d)(4)(ii) which puts the timeframe for ''prompt removal'' in the context of the inspection frequency (73 FR 74276, December 5, 2008).

The facility owner or operator may deviate from the flowline and intra-facility gathering line maintenance program requirements if an environmentally equivalent alternative measure is implemented in accordance with §112.7(a)(2). The Plan preparer certifying the Plan will typically establish the scope and frequency of inspections, tests, and preventive maintenance based on industry standards, manufacturer's recommendations, and other sources of good engineering practice. There is currently no published industry standard for a flowline or intra-facility gathering line maintenance program, however, a standard may be developed in the future. If a future industry standard is developed that meets all of the requirements described in §112.9(d)(4), then the Plan preparer may follow that standard when developing a flowline/intra-facility gathering line program for the facility. If a future standard does not address all of the SPCC rule requirements, then a PE may need to make an environmental equivalence determination. *Chapter 7: Inspection, Evaluation, and Testing* refers to selected

Tip – Intra-facility gathering lines

As described in §112.1(d)(11), intra-facility gathering lines that are subject to DOT regulatory requirements at 49 CFR part 192 (*Transportation of Natural and Other Gas by Pipeline*) or part 195 (*Transportation of Hazardous Liquids by Pipeline*) are exempt from the SPCC rule.

See Chapter 2: SPCC Rule Applicability for more information.

relevant industry standards that describe methods used to test the integrity of piping, such as API 570[78] and ASME B31.4. While these are not specific to flowlines and intra-facility gathering lines, they may serve as guidance.

A PE may determine that state requirements governing flowlines and gathering lines are environmentally equivalent to one or more of the SPCC flowline/intra-facility gathering line maintenance requirements. If alternative measures are used to meet the SPCC flowline/intra-facility gathering line maintenance program requirements in §112.9(d)(4), EPA requires that the Plan state the reasons for nonconformance and explain how the alternative measures provide environmental protection equivalent to the outlined procedures.

3.3.6 Security (Excluding Oil Production Facilities)

Section 112.7(g) of the SPCC rule outlines security requirements for facilities. These requirements are intended to prevent discharges of oil to navigable waters or adjoining shorelines that could result from acts of vandalism or other unauthorized access to oil containers or equipment. Unlike other provisions under §112.7, the security provisions in paragraph (g) do not apply to oil production facilities.

> **§112.7(g) – Security (excluding oil production facilities).**
>
> Describe in your Plan how you secure and control access to the oil handling, processing and storage areas; secure master flow and drain valves; prevent unauthorized access to starter controls on oil pumps; secure out-of service and loading/unloading connections of oil pipelines; and address the appropriateness of security lighting to both prevent acts of vandalism and assist in the discovery of oil discharges.
>
> Note: The above text is an excerpt of the SPCC rule. Refer to 40 CFR part 112 for the full text of the rule.

Prior to December 2008, the security provision of the SPCC rule required that the facility owner or operator install security systems such as fencing, locks and lighting to prevent unauthorized access to oil-handling operations and controls. However, EPA amended the facility security requirements to be more performance-based and allow an owner or operator of a facility to tailor security measures to the facility's specific characteristics and location (73 FR 74236, December 5, 2008). The security requirements remain subject to the environmental equivalence provision, but given the increased flexibility, there may be limited instances where a PE would determine that a deviation is necessary. Below we provide examples of how the revised security requirements can be met.

A facility owner or operator may achieve the rule's security objectives by providing a description of the security measures and how they are implemented at the facility. This description may include a discussion of how measures employed by the facility help deter vandals and prevent unauthorized access to containers and equipment that could be involved in an oil discharge. Measures that may be used to meet the security requirements include fencing and lighting, as appropriate for the facility.

[78] API 570 Third Edition 2009

Securing and Controlling Access to Oil Handling, Processing and Storage Areas

Fencing can serve to secure and control access to the oil handling, processing and storage areas and prevent unauthorized access to starter controls on oil pumps. As part of facility security measures, an owner or operator may *fully* fence the facility and/or guard gates when the facility is not in operation or attended.

Alternatively, for facilities where oil containers and equipment are located within discrete areas, securing only those parts of the facilities that could be involved in an oil discharge may provide an effective level of protection. This may be preferable for very large facilities where controlling access for the entire footprint of the facility would require installing and monitoring very long lengths of fencing. In such cases, installing a fence around the discrete areas of a facility where oil containers and associated valves, pumps and piping are located (*Figure 3-1*), and around the equipment needed to operate pumps and containers, may adequately deter vandals and/or prevent access by unauthorized personnel.

Figure 3-1: Fencing around oil storage area.

Other measures may also adequately control access to the facility and equipment, depending on facility-specific circumstances. One example may be a facility attended on a 24-hour basis by security or other facility personnel with closed-circuit cameras to detect and investigate unauthorized access. Alternatively, a facility may combine an alarm system that detects the presence of trespassers. The rule language no longer prescribes a single method to secure and control access to oil handling, processing and storage areas and therefore allows the facility owner or operator to determine the best method to secure these areas without explaining environmental equivalence.

Appropriateness of Lighting

The SPCC Plan must describe how the facility owner or operator addresses the appropriateness of security lighting to both prevent acts of vandalism and assist in the discovery of oil discharges. Facilities may be equipped with lights to allow facility personnel to discover discharges that occur at night and as a way to prevent acts of vandalism. Appropriate lighting may consist of motion-activated lights to ward off trespassers and allow facility personnel to notice if a discharge occurs. Alternatively, portable lights available for facility personnel to use as they perform regular rounds of the facility may be appropriate. For facilities located away from populated areas (e.g., farms or rural facilities) then the location itself may serve as a deterrent to vandals and, based on the judgment of the Plan certifier, be considered when determining whether lighting is an appropriate security measure for the facility. Alternatively, an owner/operator of an unattended facility may determine that lights at the facility would not be an effective deterrent for vandals and choose instead to fence the facility to prevent vandalism.

Another security measure that may be used to detect oil discharges (typically used at electrical substations) is a Supervisory Control and Data Acquisition (SCADA) system that monitors the facility and detects oil discharges remotely without a need for lighting to assist in visual detection.

No discussion of an environmentally equivalent alternative to security lighting is necessary because the rule does not specifically require lighting. Instead, the facility owner or operator describes in the SPCC Plan how they prevent vandalism and discover oil discharges and whether security lighting is appropriate.

3.3.7 Integrity Testing and Inspection Requirements for Bulk Storage Containers at Onshore Facilities

Integrity testing in accordance with industry standards is required for all aboveground bulk storage containers that store, use, or process petroleum and other non-petroleum oils. Requirements for bulk storage containers located at onshore facilities (excluding oil production facilities) are addressed in §112.8(c)(6). Integrity testing requirements for onshore facilities that store, use, or process animal fats and/or vegetable oils are addressed in §112.12(c)(6). For a complete discussion of integrity testing requirements and how the environmental equivalence provision applies, see *Chapter 7: Inspection, Evaluation, and Testing.*

3.3.8 Alternative Measures for Containers at Onshore Oil Production Facilities

The SPCC rule allows for alternative measures to substitute for sized secondary containment for both flow-through process vessels and produced water containers at onshore oil production facilities. The owner or operator of an oil production facility may choose to follow the alternative measures for flow-through process vessels described in §112.9(c)(5) or the measures for produced water containers as described in §112.9(c)(6), or may substitute environmentally equivalent measures in accordance with §112.7(a)(2).

The alternative measures for flow-through process vessels and produced water containers at oil production facilities are discussed in more detail in *Chapter 4: Secondary Containment and Impracticability*. The general secondary containment requirements in §112.7(c) still apply to these containers, and environmentally equivalent measures cannot be used to substitute for general secondary containment.

3.4 Review of Environmental Equivalence

Whenever an alternative measure is substituted for a prevention and control measure required by the rule, then the environmentally equivalent measure must be documented in the SPCC Plan, as required in §112.7(a)(2). This documentation is reviewed by the EPA inspector during inspections to ensure that the facility is in compliance with the regulatory requirements. The EPA inspector may refer to the list in *Table 3-5* at the end of this chapter to identify and review technical rule requirements that are eligible for deviation through the environmental equivalence provision.

As noted earlier in this Chapter, facility owners and operators may not use environmentally equivalent measures to meet general and specific secondary containment provisions of the SPCC rule. Instead, an impracticability determination in accordance with §112.7(d) provides a separate means of deviating from secondary containment requirements after a PE determines that secondary containment is not practicable.

Environmentally equivalent deviations are also not available for the general recordkeeping and training provisions in §112.7. The rule already provides flexibility in the manner of recordkeeping for inspections and tests by allowing the use of records kept under usual and customary business practices. Personnel training (§112.7(f)) and a discussion of conformance with any applicable, more stringent state rules (§112.7(j)) are essential for all facilities, and environmental equivalence does not apply to the alternative provision for qualified oil-filled operational equipment as described in §112.7(k).

3.4.1 Consideration of Costs

A PE must review the selection and implementation of environmentally equivalent measures and certify them as being consistent with good engineering practice (§112.3(d) or §112.6(b)(4)). The selection of alternative measures may be based on various considerations, such as safety, cost, geographical constraints, the appropriateness of a particular requirement based on site-specific considerations, or other factors consistent with engineering principles.

FYI – Cost considerations

EPA clarified in a Federal Register notice that under §112.7(a)(2), owners and operators of facilities may choose environmentally equivalent approaches (selected in accordance with good engineering practices) for any reason, including because they are cheaper.

(see 69 FR 29728, May 25, 2004)

Unlike impracticability claims, where cost cannot be the sole consideration (69 FR 29729, May 25, 2004), an owner or operator may consider cost as one of the factors in deciding whether to deviate from a particular requirement, but the alternative provided must achieve environmental protection equivalent to the required measure (67 FR 47095, July 17, 2002). Facilities have the opportunity to reduce costs by alternative methods if they can maintain environmental protection (67 FR 47056, July 17, 2002).

3.4.2 SPCC Plan Documentation

For each environmentally equivalent measure, the SPCC Plan must state the reason for nonconformance within the relevant section of the Plan, as required in §112.7(a)(2). The Plan must also describe the alternative measure in detail and explain how the measure provides environmental protection equivalent to that provided by the SPCC provision.

The facility owner or operator must ensure that alternative measures are adequate for the facility; that equipment, devices, or materials are designed for the intended use; and that the equipment, devices, or materials are properly implemented and maintained to provide effective environmental protection (§§112.3(d) and 112.7). EPA emphasizes that the environmental equivalence provision is not intended to be used as a means to avoid complying with the rule or simply as an excuse for not meeting requirements the owner or operator believes are too costly. The alternative measure chosen, and certified by a PE, must represent good engineering practice and must achieve environmental protection equivalent to the SPCC rule requirement as required in §112.7(a)(2).

The PE who certifies the Plan reviews environmentally equivalent measures. If a qualified facility uses environmentally equivalent measures to comply with rule requirements, a PE must specifically certify each

environmentally equivalent measure described in the Plan, as required in §112.6(b)(3)(i), even if other parts of the qualified facility Plan are self-certified by the owner/operator.

In cases where operational procedures are used as environmentally equivalent alternatives to SPCC requirements, the Plan must state the reasons for nonconformance and describe in detail the alternative methods and how the approach will achieve equivalent environmental protection (§112.7(a)(2)). The description should provide the details of how the procedures are implemented at the facility, including specific information on the steps involved in each activity, required equipment, personnel training, and records that need to be maintained to document and verify implementation. Records kept as part of usual and customary business practices are acceptable forms of documentation, but should be referenced in the Plan and available for an inspector's review during an inspection. These records must be maintained at the facility for a period of three years (§112.7(e)). Certain industry standards (for example, API Standards 570 and 653) may specify that records be maintained for more than three years. If a Plan indicates conformance with a standard that requires longer retention of inspection records, then the owner/operator should follow the longer recordkeeping requirement of the standard.

The two examples in *Figure 3-2* and *Figure 3-3* illustrate documentation of environmentally equivalent measures in hypothetical SPCC Plans. The first example in *Figure 3-2* shows *insufficient* documentation, illustrating a Plan description that simply notes the use of an alternative measure without supporting descriptions. Specifically, the example in *Figure 3-2* does not provide sufficient detail to ascertain whether the approach provides environmentally equivalent protection – it does not describe how environmental equivalence is achieved and what procedures are implemented to ensure that the measure performs as intended. The second example in *Figure 3-3* provides a sufficient level of detail to allow an EPA inspector to understand what the facility is doing to meet the objectives of the SPCC rule with regard to the given provision, and to verify implementation of the measure(s) in the field.

Figure 3-2: Example 1: Insufficient Documentation of Environmentally Equivalent Protection for Drainage of Diked Areas (§112.8(b)(1) and §112.8(b)(2)).

Facility Drainage – 40 CFR 112.8(b)(1) and 40 CFR 112.8(b)(2)

The dike structure in Area A is equipped with a [TRADEMARK] drain shutoff system and therefore does not require employee supervision during draining. This provides an environmentally equivalent method of compliance with the drainage requirement.

Figure 3-3: Example 2: Sufficient Documentation of Environmentally Equivalent Protection for Drainage of Diked Areas (§112.8(b)(1) and §112.8(b)(2)).[79]

Facility Drainage – 40 CFR 112.8(b)(1) and 40 CFR 112.8(b)(2)

The dike in Area A contains three transformers (see list of equipment and oil storage capacity in the Plan). The dike is equipped with a [TRADEMARK] drain shutoff system specifically engineered to prevent any oil from escaping the containment structure while allowing water to flow through the valve housing during normal conditions. The system uses hydrophobic and oleophilic material to block the flow of all fluids once it detects the presence of oil. The oil type stored in the containment area has been confirmed by the manufacturer to activate the oil-blocking mechanism and the mechanism ensures that any discharge from the containment structure will not cause a discharge as described in §112.1(b). Attached in an appendix to the Plan are efficacy testing results supplied by the manufacturer of [TRADEMARK].

Further documentation of the performance of this system and the manufacturer's suggested replacement interval are maintained as an appendix to this Plan. This method deviates from the rule requirement to drain dikes under direct visual supervision using valves of manual, open-and-closed design. Employee supervision is not required under regular operating conditions to drain uncontaminated rainwater that has accumulated in the dike, which will reduce manpower and resources necessary to implement the SPCC Plan. Therefore, we are implementing this system which is environmentally equivalent because it will only drain rainwater when oil is not present.

The manufacturer's maintenance and inspection requirements are maintained at the facility. In accordance with those recommendations, the diked area is inspected monthly by facility personnel as part of the scheduled inspection of bulk storage tanks, as per the checklist presented in Appendix A. This inspection includes looking for accumulation of water and presence of oil within the diked area, and examining, and replacing, as warranted, the silt filter and [TRADEMARK] elements. Facility personnel also examine the system, and replace components as needed, within 48 hours of any rainfall greater than 3 inches. Replacement of the silt filter and/or other elements of the [TRADEMARK] system are noted on the monthly inspection sheets, which are maintained at the facility for three years.

All maintenance is performed following the manufacturer's specifications. Maintenance requirements are covered in the employee training program.

In the event that the filter clogs and storm water accumulates within the diked area, facility personnel will follow required procedures for dike drainage as follows:

1) Inspect the retained rainwater to ensure that it does not contain oil (to avoid a discharge to *[Insert Name of Waterbody]* or adjoining shorelines which is the nearest navigable water to the facility);

2) Open the bypass valve, allow drainage, and reseal the valve; and

3) Record event in log.

[79] This is a hypothetical example for illustrative purposes only. The use of environmental equivalence is a site-specific determination certified by a PE in accordance with good engineering practice. EPA does not endorse this specific example as a means of environmental equivalence. If a system that uses hydrophobic and oleophilic material is used at a facility, the inspector should pay close attention to manufacturers' data supporting the assertion the system is effective to prevent a discharge as described in § 112.1(b) and PE's site-specific considerations for the use of this technology at the facility. Follow-up action by the EPA inspector may include requesting additional information from the facility owner or operator on the implementation of the equivalent measure.

3.4.3 Role of the EPA Inspector

A PE must certify environmentally equivalent measures for a facility to ensure consistency with good engineering practice (§112.3(d) or §112.6(b)(3)(i) and §112.7). For each case where an environmentally equivalent measure is used, the EPA inspector should verify that the Plan includes

- The reasons for nonconformance;
- A detailed description of the alternative measure; and
- An explanation describing how the alternative measure provides protection that is environmentally equivalent.

Additionally, the EPA inspector should verify implementation of the alternative measure in the field.

The explanation describing how an alternative measure achieves environmental equivalence does not need to demonstrate "mathematical equivalency," but the alternative measure does need to provide equivalent protection to prevent a discharge to navigable waters or adjoining shorelines. The Plan should describe how the alternative measure prevents, controls, or mitigates a discharge, as well as the procedures or equipment used to implement the alternative measure and ensure its continued effectiveness, particularly in terms of the measure's practical impacts on field operations, employee training, monitoring, and equipment maintenance.

By certifying an SPCC Plan (or portion of a Plan, in the case of a qualified facility), a PE attests that the Plan has been prepared in accordance with good engineering practice, that it meets the requirements of 40 CFR part 112, and that it is adequate for the facility. EPA encourages innovative techniques for preventing discharges, but these techniques need to effectively prevent discharges as described in §112.1(b). EPA believes that PEs will seek to protect themselves from liability by certifying only measures that provide equivalent environmental protection (67 FR 47095, July 17, 2002). If alternative measures are certified by a PE as being environmentally equivalent, are properly documented, and are appropriately implemented in the field, they should generally be considered acceptable by EPA regional inspectors absent a reasonable basis to believe otherwise.

The EPA inspector should note whether the alternative measures make sense and appear to agree with recognized industry standards or, where such standards do not apply, are in accordance with good engineering practice. An EPA inspector should also carefully review alternative approaches that purposely deviate from applicable industry consensus standards. If a PE develops an alternative measure that does not follow an applicable industry standard, then the Plan must describe why the applicable industry consensus standard is not being used and how the alternative measure is environmentally equivalent to the industry standard. The EPA inspector should assess implementation of the alternative measures, including whether they appear to have been altered or differ from the measures described in the Plan and certified by the PE, have not been implemented correctly, require maintenance that has not occurred, appear to be inadequate for the facility, or otherwise do not meet the overall oil spill prevention objective of the SPCC rule. Finally, the EPA inspector should ensure that the rule requirement for which the Plan is deviating is eligible for environmental equivalence

(as identified in §112.7(a)(2)) and that the environmentally equivalent alternative is not an existing SPCC requirement.

If the inspector questions the appropriateness of alternative measures, he/she should fully document all field observations and other pertinent information. Follow-up action by the EPA inspector may include requesting additional information from the facility owner or operator on the implementation of the equivalent measure. The EPA Regional Administrator (RA) has the authority to require amendment of the Plan to correct alternative measures. If the RA determines that the measures described in the SPCC Plan do not provide equivalent environmental protection, then the procedures for requiring a Plan amendment under §112.4(d) and (e) may be initiated. In cases of noncompliance, an enforcement action may follow, as deemed appropriate.

Test Your Knowledge

Can you identify all of the problems with the following environmental equivalence example?

Example: Rather than provide secondary containment for Tank 4 (10,000-gallon shop-built heating oil tank) we are implementing an integrity testing program that follows STI SP001. Implementation of this integrity testing program will prevent discharges of oil from the container and thus this provides equivalent environmental protection to a secondary containment dike.

What problems did you identify?

1) *Deviates from Secondary Containment Requirements*. The environmental equivalence provision in §112.7(a)(2) specifies exactly which provisions are eligible for the rule and it excludes secondary containment provisions. Instead, if the facility owner/operator in this example cannot provide adequate secondary containment for the 10,000-gallon tank, then the SPCC Plan must include an impracticability determination in accordance with §112.7(d) and he must develop an oil spill contingency plan and provide a written commitment of manpower, equipment, and materials to implement the contingency plan.

2) *Alternative Measure is an Existing SPCC Requirement*. Integrity testing is an SPCC rule requirement that applies to bulk storage containers under §§112.8(c)(6) and 112.12(c)(6). The facility owner/operator cannot substitute one SPCC rule requirement for another because this allows for a lesser degree of overall protection of navigable waters or adjoining shorelines.

3) *Inadequate Documentation.* The SPCC Plan must document the reason for deviating from a rule requirement, provide a detailed description of the alternative measure and explain how it is environmentally equivalent. The above example includes a single sentence identifying the alternative measure but does not provide a detailed description of the alternative or an explanation of why the owner/operator did not provide secondary containment for the tank. For an example of adequate documentation of environmental equivalent alternative, see *Section 3.1.1* of this chapter.

Table 3-5 lists the SPCC provisions that may be met through environmentally equivalent measures, and provides guidance on the kinds of questions an inspector should consider when reviewing environmentally equivalent measures in an SPCC Plan and during a site inspection. The table provides a list of evaluation questions for each section of the rule, means of verifying compliance during an on-site review, and elements that should be considered in cases where the facility installation does not conform with the methods described in the SPCC rule. The EPA inspector should use the part(s) of the table that are relevant to the facility being inspected.

Table 3-5: SPCC provisions subject to environmentally equivalent measures under §112.7(a)(2).

Rule Element and Relevant Section(s)	Evaluation	Verification During Inspection
Inspectors: Consider the following questions as you review the basis for environmental equivalence for each provision below. Does the Plan state the reason for nonconformance? Does the Plan describe the alternative measure in sufficient detail? Is the alternative measure appropriate for the facility? Does the Plan describe how the alternative measure is environmentally equivalent? Is the alternative measure being implemented as described? Is the proposed alternative already a rule requirement?		
ALL FACILITIES		
Administrative provisions of the SPCC rule *112.1-112.5*	***No deviation allowed based on environmental equivalence.***	
Qualified Facilities *112.6*	Deviations based on environmental equivalence are only allowed for Tier II qualified facilities. Tier II Qualified Facility Plans can include environmentally equivalent measures when a PE certifies the alternative measures in accordance with 112.6(b)(3)(1) and 112.6(b)(4). Amendments to PE-certified sections of Tier II (or hybrid) Plans must be certified by a PE in accordance with 112.6(b)(2)(i).	
General requirements for an SPCC Plan including facility description, secondary containment, recordkeeping, and personnel training *112.7 introductory paragraph and 112.7(a)-(f)*	***No deviation allowed based on environmental equivalence.***	
Security (excluding oil production facilities) *112.7(g)*	Does the Plan describe: – Measures to secure and control access to the oil handling, processing and storage areas? – Measures that ensure that master flow and drain valves are secured? – Measures that prevent unauthorized access to starter controls on oil pumps? – How the out-of-service and loading/unloading connections of oil pipelines are secured? – The appropriateness of security lighting to both prevent acts of vandalism and assist in the discovery of oil discharges?	– Visual – Plan review
Loading and unloading racks *112.7(h)(1)*	***No deviation allowed based on environmental equivalence.***	

Rule Element and Relevant Section(s)	Evaluation	Verification During Inspection
Loading and unloading racks *12.7(h)(2)*	Are loading/unloading racks equipped with an interlocked warning light or physical barrier system, warning signs, wheel chocks, or a vehicle brake interlock system to prevent vehicles from departing before complete disconnection of oil transfer lines?	– Visual review of loading operation – Plan review
Loading and unloading racks *112.7(h)(3)*	– Are the lowermost drain and all outlets of tank car or tank truck inspected for signs of discharge prior to filling and departure of the vehicles? – Are the drain and outlets tightened, adjusted, or replaced as necessary to prevent liquid discharges while in transit?	– Visual review of loading operation – Review of procedures described in the Plan
Field-constructed aboveground containers *112.7(i)*	– Has the facility conducted an evaluation of field-constructed aboveground containers undergoing repair, alteration, reconstruction, or change in service that might affect the risk of a discharge or failure? – If a field-constructed aboveground container has discharged oil or failed due to brittle fracture failure or other catastrophe, has the container been evaluated and has appropriate corrective action been taken? – Was repair/corrective action in accordance with an industry standard?	– Visual – Inspection and testing records – Brittle fracture evaluation records – Industry standard by which the brittle fracture evaluation is conducted – Industry standard by which repairs for corrective action were conducted
Conformance with state requirements *112.7(j)*	***No deviation allowed based on environmental equivalence.***	
Qualified oil-filled operational equipment *112.7(k)*	***No deviation allowed based on environmental equivalence.***	
ALL FACILITIES, EXCEPT OIL PRODUCTION		
Facility Drainage *112.8(b)(1) and 112.8(b)(2) OR 112.12(b)(1) and 112.12(b)(2)*	<u>Diked areas</u> – Is the facility drainage system or effluent treatment system designed to control oil discharges? – If not, is drainage from diked storage areas restricted by valves? – Are dikes equipped with manual valves of open-closed design? – If pumps or ejectors are used to empty the dikes, are they manually activated? – Is accumulated rainwater inspected for the presence of oil prior to draining?	– Visual – Plan review – Records of drainage events

Rule Element and Relevant Section(s)	Evaluation	Verification During Inspection
Facility Drainage *112.8(b)(3) and 112.8(b)(4) OR 112.12(b)(3) and 112.12(b)(4)*	<u>Undiked areas with potential for a discharge</u> – Does the facility have ponds, lagoons, or catchment basins designed to capture water from other areas with a potential for a discharge? – If so, are such systems designed to retain or return oil to the facility? – If not, are ditches throughout the facility designed to flow into a diversion system that would retain oil in the facility in the event of a discharge? – If the facility has catchment basins, are they located outside areas subject to periodic flooding?	– Visual – Plan review
Facility Drainage *112.8(b)(5) OR 112.12(b)(5)*	– If the facility uses more than one treatment unit to treat its drainage water, and this treatment is continuous and requires pump transfer, does the facility have at least two "lift" pumps? – Are facility drainage systems engineered to prevent discharges to navigable waters or adjoining shorelines?	– Visual – Plan review
Bulk Storage Containers *112.8(c)(1) OR 112.12(c)(1)*	Are the material and construction of oil storage containers compatible with the product stored and conditions of storage (e.g., temperature, pressure, and soil conditions)?	– Visual – Plan review – Standards/ specifications of construction (tank label), construction documents and as-built specifications
Bulk Storage Containers *112.8(c)(2) OR 112.12(c)(2)*	***No deviation allowed based on environmental equivalence.***	
Bulk Storage Containers *112.8(c)(3) OR 112.12(c)(3)*	– Does the facility prevent unsupervised drainage of rainwater into a storm drain or open watercourse, or bypassing the facility treatment system? – If so, does the facility document procedures to normally: – Keep the bypass valve sealed closed; – Inspect retained rainwater to prevent a discharge to navigable waters or adjoining shorelines; – Open the bypass valve and reseal it following supervised drainage; and – Keep adequate records of dike drainage event?	– Visual – Plan review – Records of drainage events
Bulk Storage Containers *112.8(c)(4) OR 112.12(c)(4)*	– Does the facility have completely buried metallic storage tanks that were installed after January 10, 1974? – Are completely buried metallic storage tanks protected from corrosion by coatings or cathodic protection? – Are leak tests performed regularly on these tanks?	– Visual – Plan review – Installation records – Inspection and testing records

Rule Element and Relevant Section(s)	Evaluation	Verification During Inspection
Bulk Storage Containers *112.8(c)(5) OR* *112.12(c)(5)*	– Does the facility store oil in partially buried or bunkered metallic tanks? – If so, are these tanks protected from corrosion by coatings or cathodic protection?	– Visual – Plan review – Records
Bulk Storage Containers *112.8(c)(6) OR* *112.12(c)(6)*	– Does the facility inspect or test each aboveground container (including foundation and supports) for integrity on a regular schedule, and whenever a container undergoes material repairs? – Does the Plan identify an applicable industry standard used to determine the appropriate qualifications for personnel performing tests and inspections, the frequency and type of testing and inspections? – If no applicable industry standard exists, does the Plan describe an inspection program that is in accordance with good engineering practices? – Does the facility frequently inspect the outside of each aboveground container for signs of deterioration, discharges, or accumulation or oil?	– Plan review – Applicable industry standard – Inspection program described in the Plan including the schedule and scope of such inspections – Inspection and testing records
Bulk Storage Containers *112.8(c)(7) OR* *112.12(c)(7)*	– Does the facility have containers with internal heating coils? – Does the facility monitor the steam return and exhaust lines for contamination from internal heating coils? – Does the facility pass the steam return or exhaust lines through a settling tank, skimmer, or other separation or retention system?	– Visual – Container specifications – Review of procedures described in the Plan
Bulk Storage Containers *112.8(c)(8) OR* *112.12(c)(8)*	– Are containers equipped with at least one of the following: – High liquid level alarm with audible or visual signal connected to a constantly attended station, – High liquid pump cutoff device, – Direct audible or code signal communication between container gauger and pumping station, or – A fast response system for determining the liquid level (computers, telepulse, direct vision gauges) of each bulk storage container, combined with the continuous presence of personnel to monitor filling operations. – If the SPCC Plan indicates that liquid sensing devises are tested, are the devices regularly tested to ensure proper operation?	– Visual – Review of test procedures described in the Plan – Test records
Bulk Storage Containers *112.8(c)(9) OR* *112.12(c)(9)*	Are effluent treatment facilities inspected frequently to detect possible system upsets that could cause a discharge to navigable waters or adjoining shorelines?	– Inspection and testing records – Review of inspection program described in the Plan
Bulk Storage Containers *112.8(c)(10) OR* *112.12(c)(10)*	– Are there visible discharges from containers, including seams, gaskets, piping, pumps, valves, rivets, and bolts? If so, is the facility promptly correcting such discharges? – Is there accumulation of oil in diked areas? If so, is the facility promptly removing such accumulations?	– Visual – Plan review

Rule Element and Relevant Section(s)	Evaluation	Verification During Inspection
Bulk Storage Containers *112.8(c)(11) OR* *112.12(c)(11)*	***No deviation allowed based on environmental equivalence.***	
Piping *112.8(d)(1) OR* *112.12(d)(1)*	– Does the facility have buried piping installed after August 16, 2002? If so, is this piping protected against corrosion by wrapping and coating? Is this piping cathodically protected? – Does the facility have any exposed buried piping? If so, does the facility inspect it for deterioration and undertake additional examination and corrective action as appropriate?	– Visual – Plan review – Installation records
Piping *112.8(d)(2) OR* *112.12(d)(2)*	– Does the facility have piping that is not in service or is in standby service for an extended period of time? If so, is the terminal connection at the transfer point capped or blank-flanged, and is it marked as to origin?	– Visual – Plan review
Piping *112.8(d)(3) OR* *112.12(d)(3)*	Are pipe supports properly designed to minimize abrasion and corrosion and to allow for expansion and contraction?	– Visual – Plan review
Piping *112.8(d)(4) OR* *112.12(d)(4)*	– Are aboveground valves, piping, and appurtenances regularly inspected? – *NOTE: Inspection program must address conditions of items such as flange joints, expansion joints, valve glands and bodies, catch pans, pipeline supports, locking of valves, and metal surfaces.* – Is buried piping tested for integrity and leaks when installed, modified, constructed, relocated, or replaced?	– Inspection records – Description of inspection program within the Plan – Applicable industry standard
Piping *112.8(d)(5) OR* *112.12(d)(5)*	Are all vehicles entering the facility appropriately warned to ensure that they will not endanger aboveground piping or other oil transfer operations?	Visual
ONSHORE OIL PRODUCTION FACILITIES		
Drainage *112.9(b)(1)*	– Are drains of dikes or other containment measures for tank batteries and separation/treating areas closed and sealed at all times, except when draining uncontaminated rainwater? – Prior to draining uncontaminated rainwater, does the facility inspect the diked area and take the following actions: – Document procedures to normally keep the diked drains sealed closed; – Inspect retained rainwater to prevent a discharge to navigable waters or adjoining shorelines; – Open the bypass valve and reseal it following supervised drainage; and – Keep adequate records of dike drainage event? – And is accumulated oil removed and either returned to storage or disposed of properly?	– Visual – Plan review – Records of drainage events

Rule Element and Relevant Section(s)	Evaluation	Verification During Inspection
Drainage *112.9(b)(2)*	– Are field drainage systems and oil traps, sumps, or skimmers regularly inspected for accumulation of oil? – And is accumulated oil promptly removed?	– Visual – Inspection records – Inspection program described in the Plan, including the schedule and scope of such inspections
Bulk Storage Containers *112.9(c)(1)*	Are the material and construction of oil storage containers compatible with the product stored and conditions of storage (e.g., temperature, pressure, and soil conditions)?	– Visual – Construction standards (tank labels, as-build specifications, etc.) – Visual indication of incompatibility, (i.e., excessive corrosion)
Bulk Storage Containers *112.9(c)(2)*	***No deviation allowed based on environmental equivalence.***	
Bulk Storage Containers *112.9(c)(3)*	Is each container visually inspected periodically and on a regular schedule? *NOTE: Inspections must cover foundation and support of each container that is on or above the ground surface.*	– Inspection records – Inspection program described in the Plan, including scope and frequency of such inspections
Bulk Storage Containers *112.9(c)(4)*	– Are tank battery installations engineered to prevent discharges using one of the following: – Container capacity is adequate to prevent overfill if gauger/pumper is delayed in making regularly schedule rounds – Equipped with overflow equalizing lines between containers – Adequate vacuum protection to prevent container collapse during transfer of oil – High level sensors to alert computer where the facility is subject to a computer production control system	– Visual – Plan review

Rule Element and Relevant Section(s)	Evaluation	Verification During Inspection
Bulk Storage Containers – Flow-through Process Vessels *112.9(c)(5)*	− Does the facility owner/operator comply with secondary containment and inspection requirements of 112.9(c)(2) and (c)(3) for flow-through process vessels? − If not, then does the facility comply with the secondary containment requirements of 112.7(c) and implement the following alternative compliance option for this equipment: − Visually inspect and/or test flow-through process vessels and associated components periodically for leaks, corrosion, or other conditions that could lead to a discharge to navigable waters or adjoining shorelines; − Take corrective action or repair flow-through process vessels and any associated components as necessary; and − Promptly remove or initiate actions to stabilize and remediate any accumulations of oil discharges associated with flow-through process vessels. − Has the facility discharged more than 1,000 U.S. gallons of oil in a single discharge as described in §112.1(b), or discharges more than 42 U.S. gallons of oil in each of two discharges as described in §112.1(b) within any twelve month period, from flow-through process vessels (excluding discharges that are the result of natural disasters, acts of war, or terrorism)? − If so, did the facility ensure that all flow-through process vessels subject to this subpart comply with §112.9(c)(2) and (c)(3) within six months from the discharge(s)?	− Plan review − Visual − Inspection records − Spill history/spill reports

Rule Element and Relevant Section(s)	Evaluation	Verification During Inspection
Bulk Storage Containers – Produced Water Containers *112.9(c)(6)*	– Does the facility owner/operator comply with secondary containment and inspection requirements of 112.9(c)(2) and (c)(3) for produced water containers? – If not, then does the facility comply with the secondary containment requirements of 112.7(c) and implement the following alternative compliance option for this equipment: – Implement a procedure to separate the free-phase oil that accumulates on the surface of the produced water, on a regular schedule, for each produced water container; – Does the Plan describe the procedures, frequency, amount of free-phase oil expected to be maintained inside the container, and include a PE certification in accordance with §112.3(d)(1)(vi); – Maintain records of such events; – Visually inspect and/or test the produced water container and associated piping on a regular schedule, for leaks, corrosion, or other conditions that could lead to a discharge to navigable waters and adjoining shorelines; – Take corrective action or repair produced water containers and any associated piping as necessary; and – Promptly remove or initiate actions to stabilize and remediate any accumulations of oil discharges associated with the produced water container. – Has the facility discharged more than 1,000 U.S. gallons of oil in a single discharge as described in §112.1(b), or discharges more than 42 U.S. gallons of oil in each of two discharges as described in §112.1(b) within any twelve month period, from flow-through process vessels (excluding discharges that are the result of natural disasters, acts of war, or terrorism)? – If so, did the facility ensure that all produced water containers subject to this subpart comply with §112.9(c)(2) and (c)(3) within six months from the discharge(s)?	– Plan review – Visual – Inspection records – Spill history/spill reports
Transfer operations *112.9(d)(1)*	Are all aboveground valves and piping inspected periodically and upon a regular schedule? *NOTE: Inspections must cover items such as flange joints, valve glands and bodies, drip pans, pipe supports, pumping well polish rod stuffing boxes, and bleeder and gauge valves.*	– Inspection and testing records – Inspection program described in the Plan, including frequency and scope of inspections
Transfer operations *112.9(d)(2)*	Are saltwater disposal facilities inspected, particularly following a sudden change in atmospheric temperature?	– Plan review – Inspection and testing records
Transfer operations *112.9(d)(3)*	***No deviation allowed based on environmental equivalence.***	

Rule Element and Relevant Section(s)	Evaluation	Verification During Inspection
Transfer operations *112.9(d)(4)*	– Did the facility prepare and implement a written program of flowline/intra-facility gathering line maintenance that addresses the following: – Equipment is compatible with the type of production fluids, their potential corrosivity, volume, and pressure, and other conditions expected in the operational environment; – Flowlines and intra-facility gathering lines and associated appurtenances are visually inspected and/or tested on a periodic and regular schedule; – Frequency and type of testing allows for the implementation of a contingency plan as described in 40 CFR 109 for those flowlines and intra-facility gathering lines that are not provided with secondary containment; – Corrective action is taken or repairs are made for flowlines and intra-facility gathering lines and associated appurtenances as necessary; and – Any accumulations of oil discharges associated with flowlines, intra-facility gathering lines, and associated appurtenances are promptly removed or actions initiated to stabilize and remediate.	– Inspection and maintenance records. – Program of flowline maintenance described in the Plan, including the scope and frequency of maintenance
ONSHORE OIL DRILLING AND WORKOVER FACILITIES		
Mobile drilling or workover equipment *112.10(b)*	Is the equipment located so as to prevent a discharge to navigable waters or adjoining shorelines?	– Visual – Plan review
Containment *112.10(c)*	***No deviation allowed based on environmental equivalence.***	
Blowout prevention *112.10(d)*	– Are a blowout prevention (BOP) assembly and well control system installed before drilling below any casing string or during workover operations? – Are the BOP assembly and well control system capable of controlling well-head pressure?	– Visual – Installation record – Plan review
OFFSHORE OIL DRILLING, PRODUCTION AND WORKOVER FACILITIES		
Drainage *112.11(b)*	– Is oil drainage collection equipment used to prevent and control small discharges? Are facility drains directed toward a central collection sump? – If a sump is not practicable, is oil removed from collection equipment as often as necessary to prevent overflow?	– Visual – Plan review
Drainage *112.11(c)*	– If a sump system is employed, are the sizes of pump and sump adequate? Is a spare pump available? – If a sump system is employed, does the facility have in place a regularly scheduled preventive maintenance inspection and testing program to assure reliable operation? – Are redundant automatic sump pump and control devices provided (when necessary)?	– Visual – Plan review – Preventive maintenance inspection and testing program described in the Plan

Rule Element and Relevant Section(s)	Evaluation	Verification During Inspection
Separators and Treaters *112.11(d)*	– Does the facility have areas where separators and treaters are equipped with dump valves which predominantly fail in the closed position and where the pollution risk is high? If so, is the facility specially equipped to prevent the discharge of oil, including: – Extending the flare line to a diked area if the separator is near shore? – Equipping the separator with a high liquid level sensor that will automatically shut in wells producing to the separator, or – Installing parallel redundant dump valves?	– Visual – Description of inspection and maintenance of separators and heater treaters (including dump valves) in the Plan, including the schedule and scope of such inspections
Containers *112.11(e)*	Are atmospheric storage or surge containers equipped with high liquid level sensing devices that activate an alarm or control the flow, or otherwise prevent discharges?	– Visual – Plan review
Containers *112.11(f)*	Are pressure containers equipped with high and low pressure sensing devices that activate an alarm or control the flow?	– Visual – Plan review
Containers *112.11(g)*	Are containers equipped with suitable corrosion protection?	– Visual – Plan review
Pollution prevention equipment and systems *112.11(h)*	Does the Plan include a written procedure for inspecting and testing pollution prevention equipment and systems?	Plan review
Pollution prevention equipment and systems *112.11(i)*	– Are the pollution prevention equipment and systems tested and inspected on a scheduled periodic basis? – Is the facility testing and inspecting human and equipment pollution control and countermeasure systems by using simulated discharges?	– Inspection and testing records – Description of inspection and testing program in Plan, including scope and frequency
Well shut-in valves *112.11(j)*	Is the method of activation or control of well shut-in valves and devices for each well described in sufficient details?	Plan review
Blowout Prevention *112.11(k)*	– Is a BOP assembly and well control system installed during workover operations or before drilling below any casing string? – Is the BOP assembly and well control system capable of controlling well-head pressure that may be encountered?	– Visual – Plan review – Installation records
Flowlines *112.11(l)*	Are manifolds (headers) equipped with check valves on individual flowlines?	– Visual – Plan review
Flowlines *112.11(m)*	– When the shut-in well pressure is greater than the working pressure of the flowline are flowlines equipped with a high pressure sensing device and shut-in valve at the wellhead? and – Are valves manifolded up to and including the header valves? If not, is a pressure relief system provided for flowlines?	– Visual – Plan review

Rule Element and Relevant Section(s)	Evaluation	Verification During Inspection
Piping *112.11(n)*	Is all piping appurtenant to the facility protected from corrosion, such as with protective coating or cathodic protection?	– Visual – Plan review – Installation records
Piping *112.11(o)*	Is sub-marine piping adequately protected against environmental stresses and other activities such as fishing operations?	– Inspection and maintenance program described in Plan – Installation records
Piping *112.11(p)*	– Is sub-marine piping appurtenant to the facility maintained in good operating condition at all times? – Does the facility have a program to inspect or test sub-marine piping for failures according to a regular schedule? – Does the facility maintain a record of these inspections or tests?	– Inspection and testing records – Review of inspection or testing program described in Plan, including scope and frequency of inspections or tests

Chapter 4 Secondary Containment and Impracticability

4.1 Introduction

The purpose of the SPCC rule is to prevent discharges of oil into navigable waters of the United States and adjoining shorelines. One of the primary ways the rule sets out to accomplish this goal is by requiring secondary containment. A secondary containment system provides an essential line of defense in the event of a failure of the primary containment, such as a bulk storage container, a mobile or portable container, piping, or oil-filled equipment. The system provides temporary containment of discharged oil until the appropriate actions are taken to abate the source of the discharge and remove oil from areas where it has accumulated to prevent it from reaching navigable waters or adjoining shorelines. The rule includes two categories of secondary containment requirements:

- A **general provision** addresses the potential for oil discharges from all regulated parts of a facility. The containment method, design, and capacity are determined by good engineering practice to contain the most likely discharge of oil until cleanup occurs.
- **Specific provisions** address the potential of oil discharges from areas of a facility where oil is stored or handled. The containment design, sizing, and freeboard requirements are specified by the SPCC rule to address a major container failure.

The *general* secondary containment requirements are intended to address, in accordance with good engineering practice, the most likely oil discharges from areas or containers such as mobile refuelers and other non-transportation-related tank trucks; oil-filled operational or process equipment; (non-rack) transfer areas; or piping. In determining the method, design, and capacity for general secondary containment, only the typical failure mode needs to be considered.

The *specific* secondary containment requirements are intended to address a major container failure (e.g., the entire contents of the container and/or compartment) associated with a bulk storage container; single compartment of a tank car or tank truck at a loading/unloading rack; mobile/portable containers; and production tank batteries, treatment, and separation installations (including flow-through process vessels and produced water containers). These specific provisions (see *Table 4-1* in *Section 4.1.1*) provide explicit requirements for sizing, design, and freeboard.

The purpose of this chapter is to clarify the relationships among the various general and specific secondary containment requirements of the SPCC rule, and to illustrate how these requirements apply. This chapter also discusses the rule's impracticability determination provision, which may be used when a facility owner/operator cannot install secondary containment by any reasonable method. The additional requirements that accompany an impracticability determination, the documentation needed to support such a determination,

and the role of the EPA inspector in reviewing secondary containment requirements and impracticability determinations are also discussed.

The remainder of this chapter is organized as follows.

- ***Section 4.2*** provides an overview of the SPCC rule's general secondary containment provisions, including exceptions to the requirement to provide secondary containment.
- ***Section 4.3*** discusses the specific secondary containment requirements and the meaning of "sufficient freeboard."
- ***Section 4.4*** discusses issues related to secondary containment, such as active versus passive measures, the "sufficiently impervious" requirement, facility drainage, and man-made structures.
- ***Section 4.5*** describes the impracticability determination provision.
- ***Section 4.6*** describes required measures when secondary containment is impracticable.
- ***Section 4.7*** discusses how the impracticability determination may be used in certain circumstances.
- ***Section 4.8*** discusses alternative measures in the rule in lieu of secondary containment at oil production facilities.

4.1.1 Overview of Secondary Containment Provisions

The SPCC rule includes several secondary containment provisions intended to address the various activities or locations at a facility where oil is handled. This section differentiates among these general and specific secondary containment provisions.

Table 4-1 lists all the secondary containment provisions of the SPCC rule for different types of facilities.

Table 4-1: Secondary containment provisions in 40 CFR part 112.

Type of Facility	Secondary Containment	Rule Section(s)
All Facilities	General containment (areas with potential for discharge, such as piping–including flowlines, bulk storage containers, oil-filled operating and manufacturing equipment, and oil equipment associated with transfer areas)	§112.7(c)
	Mobile refuelers and other non-transportation-related tank trucks.	§112.7(c)
	Loading/unloading racks**	§112.7(h)(1)
	Qualified Oil-Filled Operational Equipment	§112.7(c) or alternate measures in §112.7(k)
Onshore Storage	Bulk storage containers (except mobile refuelers and other non-transportation-related tank trucks)	§112.8(c)(2) or §112.12(c)(2)
	Mobile or portable oil containers (except mobile refuelers and other non-transportation-related tank trucks)	§112.8(c)(11) or §112.12(c)(11)
Onshore Oil Production	Bulk storage containers, including tank batteries, separation, and treating facility installations (except for flow-through process vessels and produced water containers)	§112.9(c)(2)
	Flow-through process vessels	§112.9(c)(2) or §112.7(c) and alternate measures in §112.9(c)(5)
	Flowlines and intra-facility gathering lines	§112.7(c) or alternate measures in §112.9(d)(3)
	Produced water containers	§112.9(c)(2) or §112.7(c) and alternate measures in §112.9(c)(6)
Onshore Oil Drilling and Workover	Mobile drilling or workover equipment	§112.10(c)
Offshore Oil Drilling, Production, and Workover	Oil drilling, production, or workover equipment	§112.7(c)

** Although this requirement applies to all facilities, loading/unloading racks are generally not present at typical oil production facilities or farms, as discussed in *Section 4.7.3*.

Figure 4-1 through *Figure 4-4* illustrate the relationships between the secondary containment requirements at various types of facilities. EPA inspectors should use the flowchart that corresponds to the type of facility he or she is inspecting (see the figure description for each flowchart). The second row of each flowchart identifies the types of containers, equipment, and activities or areas where oil is handled, with

reference to the appropriate secondary containment rule provision. The flowcharts note the use of impracticability determinations and additional design considerations for other areas with the potential for discharge.

Figure 4-1: Secondary containment provisions in 40 CFR part 112 related to onshore storage facilities (§§112.7 and 112.8 or 112.12).

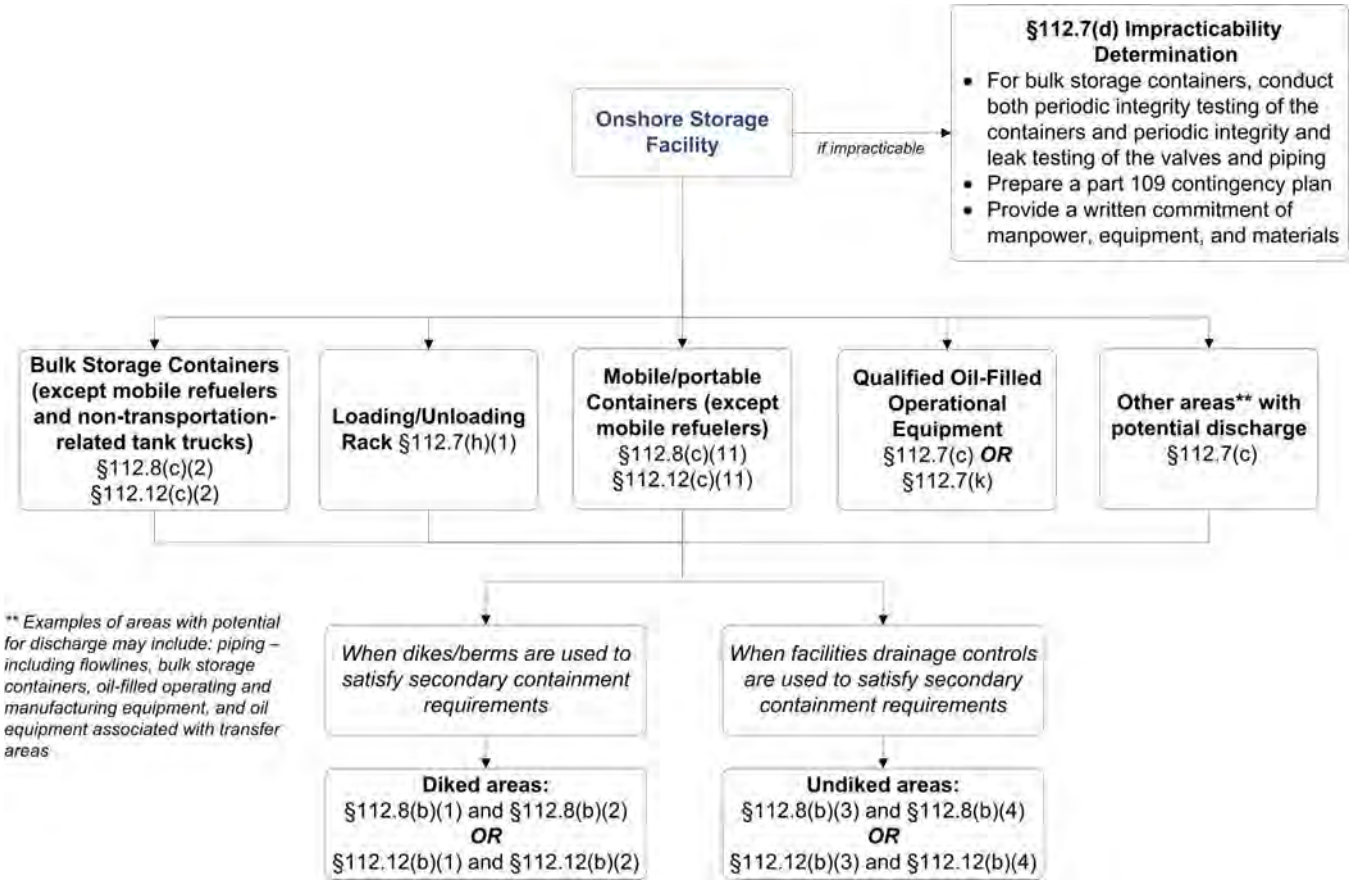
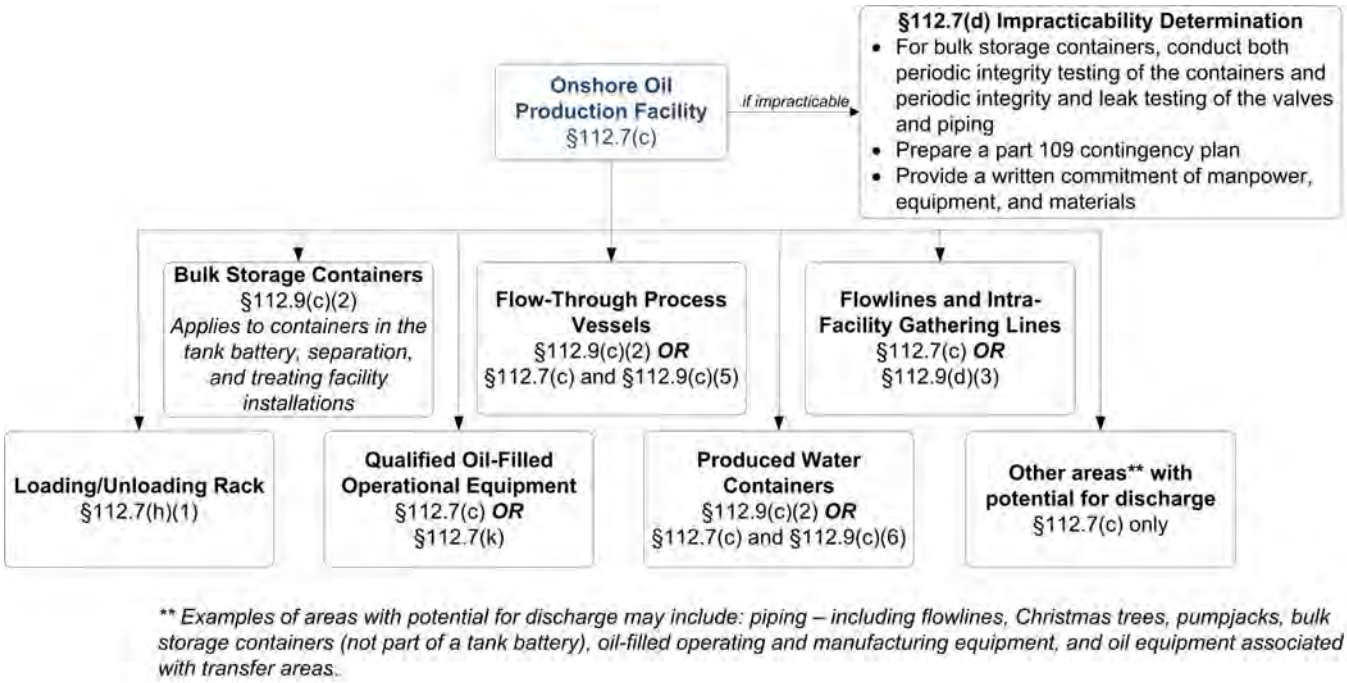
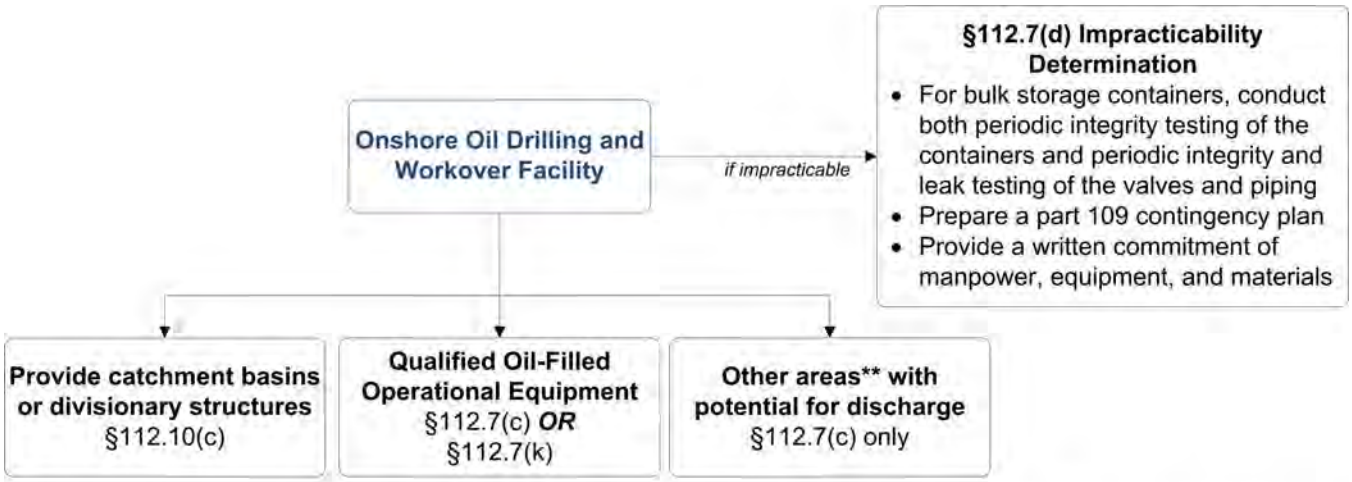


Figure 4-2: Secondary containment provisions in 40 CFR part 112 related to onshore oil production facilities (§§112.7 and 112.9).



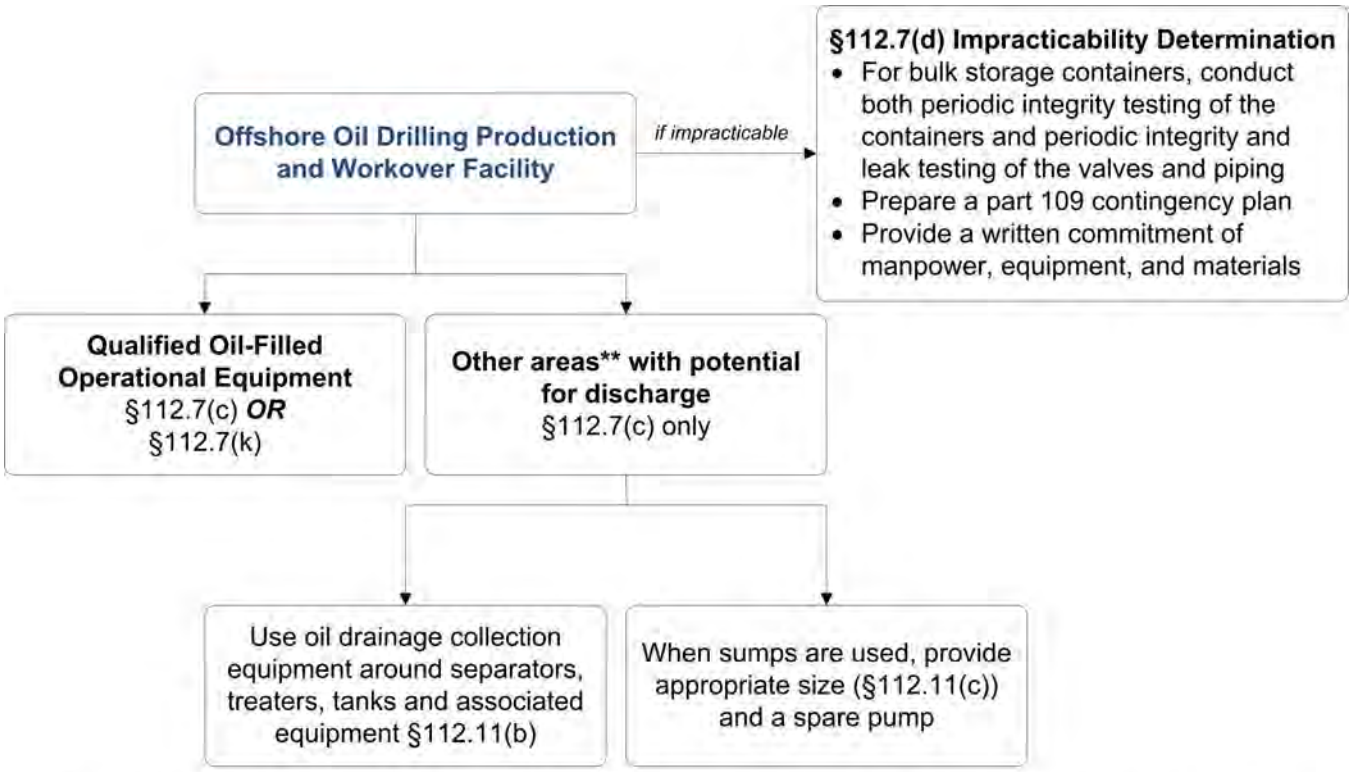
Oil production facilities do not typically have loading/unloading racks as defined in §112.2, but when oil is transferred through a loading/unloading rack, sized secondary containment in accordance with §112.7(h)(1) applies. Oil transfers to trucks within oil production facilities normally occur at transfer areas that are subject to general secondary containment in accordance with §112.7(c).

Figure 4-3: Secondary containment provisions in 40 CFR part 112 related to onshore oil drilling and workover facilities (§§112.7 and 112.10).



*** Examples of areas with potential for discharge may include: piping – including flowlines, bulk storage containers, additive tanks containing oil, lubricant oil tanks, oil-filled operating and manufacturing equipment, and oil equipment associated with transfer areas.*

Figure 4-4: Secondary containment provisions in 40 CFR part 112 related to offshore oil drilling, production, and workover facilities (§§112.7 and 112.11).[80]



*** Examples of areas with potential for discharge may include: piping – including flowlines, wellheads, blowout preventers, stock tanks, bulk storage containers, additive tanks containing oil, lubricant oil tanks, oil-filed operating and manufacturing equipment, flow-through process vessels, oil tanks for drilling rigs, and oil equipment associated with transfer areas.*

4.2 General Secondary Containment Requirements

At a regulated facility, all areas and equipment with the potential for a discharge are subject to the general secondary containment provision, §112.7(c). These may include bulk storage containers; mobile/portable containers; mobile refuelers and other non-transportation-related tank trucks; oil production tank batteries, treatment, and separation installations; pieces of oil-filled operational or manufacturing equipment; loading/unloading areas (also referred to as transfer areas); and piping; and may include other areas of a facility where oil is present. For the areas where specific (sized) secondary containment is also required (as described in Section 4.7), this sized secondary containment fulfills the general secondary containment requirements. The general secondary containment provision requires that these areas be designed with appropriate containment and/or diversionary structures to prevent a discharge in quantities that may be harmful (i.e., a discharge as described in §112.1(b)). "Appropriate containment" must be designed to address the *most likely* quantity of oil that would be discharged from the primary containment system (e.g., container,

[80] Onshore components associated with offshore facilities may also be subject to §§112.8 or 112.9 requirements (as applicable).

equipment), such that the discharge will not escape secondary containment before cleanup occurs. In determining the most likely quantity, the facility owner/operator should consider factors such as the typical failure mode (e.g., overfill, fracture in container wall, etc.), resulting oil flow rate, facility personnel response time, and the duration of the discharge. An example calculation for a transfer area is included in *Section 4.7.2*. A similar calculation can be applied for any area or equipment subject to the general secondary containment requirement (e.g., oil-filled equipment such as transformers). Calculations may be provided as part of the documentation to support the adequacy of secondary containment measures employed at the facility, although they are not required. Nevertheless, the Plan preparer must include enough detail in the SPCC Plan to describe the efficacy of the measures used to comply with the general secondary containment requirements in §112.7(c).

Section 112.7(c) lists several methods of providing secondary containment, which are described in *Table 4-2*. These methods are examples only; other containment methods may be used, consistent with good engineering practice. For example, a facility could use an oil/water separator, combined with a drainage system, to collect and retain discharges of oil within the facility. PE certification (or self-certification, in the case of qualified facilities) of the SPCC Plan includes verification that the selected secondary containment methods for the facility are appropriate and follow good engineering practice.

§112.7(c)

Provide appropriate containment and/or diversionary structures or equipment to prevent a discharge as described in §112.1(b) except as provided in paragraph (k) of this section for qualified oil-filled operational equipment, and except as provided in §112.9(d)(3) for flowlines and intra-facility gathering lines at an oil production facility. The entire containment system, including walls and floor, must be capable of containing oil and must be constructed so that any discharge from a primary containment system, such as a tank or pipe, will not escape the containment system before cleanup occurs. In determining the method, design, and capacity for secondary containment, you need only to address the typical failure mode, and the most likely quantity of oil that would be discharged. Secondary containment may be either active or passive in design. At a minimum, you must use one of the following prevention systems or its equivalent:

(1) For onshore facilities:
(i) Dikes, berms, or retaining walls sufficiently impervious to contain oil;
(ii) Curbing or drip pans;
(iii) Sumps and collection systems;
(iv) Culverting, gutters, or other drainage systems;
(v) Weirs, booms, or other barriers;
(vi) Spill diversion ponds;
(vii) Retention ponds; or
(viii) Sorbent materials.

(2) For offshore facilities:
(i) Curbing or drip pans; or
(ii) Sumps and collection systems.

Note: The above text is an excerpt of the SPCC rule. Refer to 40 CFR part 112 for the full text of the rule.

Discharge as described in §112.1(b) is a discharge in quantities that may be harmful, as described in part 110 of this chapter [40 CFR part 110], into or upon the navigable waters of the United States or adjoining shorelines, or into or upon the waters of the contiguous zone, or in connection with activities under the Outer Continental Shelf Lands Act or the Deepwater Port Act of 1974, or that may affect natural resources belonging to, appertaining to, or under the exclusive management authority of the United States (including resources under the Magnuson Fishery Conservation and Management Act).

Note: The above text is an excerpt of the SPCC rule. Refer to 40 CFR part 112 for the full text of the rule.

Table 4-2: Example methods of secondary containment listed in §112.7(c).

Secondary Containment Method	Description of Examples
Dikes, berms, or retaining walls sufficiently impervious to contain oil	Types of permanent engineered barriers, such as raised earth embankments or concrete containment walls, designed to hold oil. Normally used in areas with potential for large discharges, such as single or multiple aboveground storage tanks and certain piping. Temporary dikes and berms may be constructed after a discharge is discovered as an active containment measure (or a countermeasure) so long as they can be implemented in time to prevent the spilled oil from reaching surface waters. Please see *Section 4.4.1*, *Passive versus Active Measures of Secondary Containment*.
Curbing	Typically consists of a permanent reinforced concrete or an asphalt apron surrounded by a concrete curb. Can also be of a uniform, rectangular cross-section or combined with mountable curb sections to allow access to loading/unloading vehicles and materials handling equipment. Can be used where only small spills are expected and also used to direct spills to drains or catchment areas. Temporary curbing may be constructed after a discharge is discovered as an active containment measure (or a countermeasure) so long as it can be implemented in time to prevent the spilled oil from reaching surface waters. Please see *Section 4.4.1*, *Passive versus Active Measures of Secondary Containment*.
Culverting, gutters, or other drainage systems	Types of permanent drainage systems designed to direct spills to remote containment or treatment areas. Ideal for situations where spill containment structures cannot or should not be located immediately adjacent to the potential spill source.
Weirs	Dam-like structures with a notch through which oil may flow to be collected. Generally used in combination with skimmers to remove oil from the surface of water.
Booms	Form a continuous barrier placed as a precautionary measure to contain/collect oil. Typically used for the containment, exclusion, or deflection of oil floating on water, and is usually associated with an oil spill contingency or facility response plan to address oil spills that have reached surface waters. Beach booms are designed to work in shallow or tidal areas. Sorbent-filled booms can be used for land-based spills. There are very limited applications for use of booms for land-based containment of discharged oil.
Barriers	Spill mats, storm drain covers, and dams used to block or prevent the flow of oil. Temporary barriers may be put in place prior to a discharge or after a discharge is discovered. These are all considered effective active containment measures (or countermeasures) as long as they can be implemented in time to prevent the spilled oil from reaching navigable waters and adjoining shorelines. Please see *Section 4.4.1*, *Passive versus Active Measures of Secondary Containment*.

Secondary Containment Method	Description of Examples
Spill diversion ponds and retention ponds	Designed for long-term or permanent containment of storm water, but also capable of capturing and holding oil or runoff and preventing it from entering surface water bodies. Temporary spill diversion ponds and retention ponds may be constructed after a discharge is discovered as an active containment measure (or countermeasure) as long as they can be implemented in time to prevent the spilled oil from reaching navigable waters and adjoining shorelines. There are very limited applications for use of temporary spill diversion and retention ponds for land-based containment of discharged oil due to the timely availability of the appropriate excavation equipment required to rapidly construct the ponds. Please see *Section 4.4.1*, *Passive versus Active Measures of Secondary Containment*.
Sorbent materials	Insoluble materials or mixtures of materials (packaged in forms such as spill pads, pillows, socks, and mats) used to recover liquids through the mechanisms of absorption, adsorption, or both. Materials include clay, vermiculite, diatomaceous earth, and man-made materials. Used to isolate and contain small drips or leaks until the source of the leak is repaired. Commonly used with material handling equipment, such as valves and pumps. Also used as an active containment measure (or countermeasure) to contain and collect small-volume discharges before they reach waterways. Proper use of these materials may require a properly equipped and trained spill response team specifically trained to contain an oil discharge *prior to* reaching navigable waters or adjoining shorelines Please see *Section 4.4.1*, *Passive versus Active Measures of Secondary Containment*.
Drip pans	Used to isolate and contain small drips or leaks until the source of the leak is repaired. Drip pans are commonly used with product dispensing containers (usually drums), when uncoupling hoses during bulk transfer operations, and for pumps, valves, and fittings.
Sumps and collection systems	A permanent pit or reservoir and its associated troughs/trenches that collect oil.

The general secondary containment provision applies to all areas of a facility that have a potential to cause an oil discharge. However, the provision allows for alternative measures in the SPCC Plan for:

- Qualified oil-filled operational equipment; and
- Flowlines and intra-facility gathering lines

These alternative measures are further described below.

4.2.1 Alternative Measures for General Secondary Containment Requirement: Qualified Oil-Filled Operational Equipment

Providing adequate secondary containment for oil-filled operational equipment is often impracticable, therefore, the SPCC rule provides an optional alternative to the general secondary containment requirements for oil-filled operational equipment that meets qualifying criterion in §112.7(k) (commonly referred to as "qualified oil-filled operational equipment").

Oil-filled operational equipment, as defined in §112.2, is equipment that includes an oil storage container (or multiple containers) in which the oil present is used solely to support the function of the apparatus or the device. For more information on oil-filled equipment, refer to *Chapter 2: SPCC Rule Applicability.*

§112.2

Oil-filled operational equipment means equipment that includes an oil storage container (or multiple containers) in which the oil is present solely to support the function of the apparatus or the device. Oil-filled operational equipment is not considered a bulk storage container, and does not include oil-filled manufacturing equipment (flow-through process). Examples of oil-filled operational equipment include, but are not limited to, hydraulic systems, lubricating systems (*e.g.*, those for pumps, compressors and other rotating equipment, including pumpjack lubrication systems), gear boxes, machining coolant systems, heat transfer systems, transformers, circuit breakers, electrical switches, and other systems containing oil solely to enable the operation of the device.

Note: The above text is an excerpt of the SPCC rule. Refer to 40 CFR part 112 for the full text of the rule.

§112.7(k)

Qualified Oil-filled Operational Equipment. The owner or operator of a facility with oil-filled operational equipment that meets the qualification criteria in paragraph (k)(1) of this sub-section may choose to implement for this qualified oil-filled operational equipment the alternate requirements as described in paragraph (k)(2) of this sub-section in lieu of general secondary containment required in paragraph (c) of this section.

(1) *Qualification Criteria—Reportable Discharge History:* The owner or operator of a facility that has had no single discharge as described in § 112.1(b) from any oil-filled operational equipment exceeding 1,000 U.S. gallons or no two discharges as described in § 112.1(b) from any oil-filled operational equipment each exceeding 42 U.S. gallons within any twelve month period in the three years prior to the SPCC Plan certification date, or since becoming subject to this part if the facility has been in operation for less than three years (other than oil discharges as described in § 112.1(b) that are the result of natural disasters, acts of war or terrorism)

(2) *Alternative Requirements to General Secondary Containment.* If secondary containment is not provided for qualified oil-filled operational equipment pursuant to paragraph (c) of this section, the owner or operator of a facility with qualified oil-filled operational equipment must:

(i) Establish and document the facility procedures for inspections or a monitoring program to detect equipment failure and/or a discharge; and

(ii) Unless you have submitted a response plan under §112.20, provide in your Plan the following:

(A) An oil spill contingency plan following the provisions of part 109 of this chapter.

(B) A written commitment of manpower, equipment, and materials required to expeditiously control and remove any quantity of oil discharged that may be harmful.

Note: The above text is an excerpt of the SPCC rule. Refer to 40 CFR part 112 for the full text of the rule.

Determining Eligibility for Alternative Measures for Oil-Filled Operational Equipment

The facility owner/operator determines if he is eligible to use the alternative measures in §112.7(k) by considering the reportable discharge history from any oil-filled operational equipment at the facility. *Table 4-3* identifies the criterion for determining if the facility has qualified oil-filled operational equipment.

Table 4-3: Reportable discharge history criterion for oil-filled operational equipment.

You must answer no to the following to be eligible for alternative measures in §112.7(k): In the three years before the SPCC Plan is certified, has the facility had any discharges to navigable waters or adjoining shorelines from **oil-filled operational equipment** as described below:	
A single discharge of oil greater than 1,000 gallons?	Yes or No
Two discharges of oil each greater than 42 gallons within any 12-month period?	Yes or No

When considering the above questions, the owner/operator does not need to include discharges that are the result of natural disasters, acts of war, or terrorism. Additionally, when determining the applicability of this SPCC reporting requirement, the gallon amount(s) specified (either 1,000 or 42) refers to the amount of oil that actually reaches navigable waters or adjoining shorelines, not the total amount of oil spilled. EPA considers the entire volume of the discharge to be oil for the purposes of these reporting requirements.

Let's consider the following examples:

Example 1: A facility has one discharge from oil-filled operational equipment over the past three years in which 1,500 gallons of oil discharged onto the ground but only 20 gallons reached navigable waters or adjoining shorelines (causing a sheen and reportable to the NRC).

You must answer no to the following to be eligible for alternative measures in §112.7(k): In the three years before the SPCC Plan is certified, has the facility had any discharges to navigable waters or adjoining shorelines **from oil-filled operational equipment** as described below:	
A single discharge of oil greater than 1,000 gallons?	**No**
Two discharges of oil each greater than 42 gallons within any 12-month period?	**No**

Does the facility have qualified oil-filled operational equipment? Yes. The facility has qualified oil-filled operational equipment because there was only one reportable oil discharge from oil-filled operational equipment and the amount discharged to navigable waters (20 gallons) was less than 1,000 gallons (i.e., they met the reportable discharge history criterion).

Example 2: A facility has one 1,500-gallon discharge from oil-filled operational equipment to navigable waters.

You must answer no to the following to be eligible for alternative measures in §112.7(k):	
In the three years before the SPCC Plan is certified, has the facility had any discharges to navigable waters or adjoining shorelines **from oil-filled operational equipment** as described below:	
A single discharge of oil greater than 1,000 gallons?	**Yes**
Two discharges of oil each greater than 42 gallons within any 12-month period?	**No**

Does the facility have qualified oil-filled operational equipment? No. In this example, the oil discharge to navigable waters was larger than 1,000 gallons and therefore the facility does not qualify for alternative measures.

Example 3: A 2,000-gallon oil discharge to navigable waters occurs while unloading a vehicle into a bulk storage container.

You must answer no to the following to be eligible for alternative measures in §112.7(k):	
In the three years before the SPCC Plan is certified, has the facility had any discharges to navigable waters or adjoining shorelines **from oil-filled operational equipment** as described below:	
A single discharge of oil greater than 1,000 gallons?	**No**
Two discharges of oil each greater than 42 gallons within any 12-month period?	**No**

Does the facility have qualified oil-filled operational equipment? Yes. The facility has qualified oil-filled operational equipment because the oil discharge did not originate from oil-filled operational equipment and therefore is not considered when determining eligibility of the facility to use alternative measures for qualified oil-filled operational equipment.

Alternative Measures

If an owner or operator uses alternative measures in lieu of meeting the secondary containment requirements for qualified oil-filled operational equipment., he or she is required to establish and document an inspection or monitoring program for qualified oil-filled operational equipment to detect equipment failure and/or a discharge. Additionally, the owner/operator must prepare an oil spill contingency plan and provide a written commitment of manpower, equipment, and materials required to expeditiously control and remove any quantity of oil discharged that may be harmful (unless the facility has submitted a Facility Response Plan.) The advantage of the §112.7(k) alternative to the general secondary containment requirements is that the facility owner/operator is not required to prepare an impracticability determination for the qualified oil-filled operational equipment (impracticability determinations are discussed in *Section 4.5* of this chapter). Note that the use of alternative measures is optional for qualified oil-filled operational equipment; the owner/operator can instead provide secondary containment or may prepare an impracticability determination.

For facility owners and operators that rely on contingency planning for qualified oil-filled operational equipment in lieu of secondary containment, the discovery of a discharge by inspection or monitoring is critical for effective and timely implementation of the contingency plan. An inspection or monitoring program ensures that facility personnel are alerted quickly of equipment failures and/or discharges. The SPCC Plan must describe the inspection or monitoring program and the owner or operator must keep a record of inspections and tests, signed by the appropriate supervisor or inspector, for a period of three years in accordance with §112.7(e).

Qualified Oil-Filled Operational Equipment and Qualified Facilities Overlap

Some facilities may meet the criteria for qualified facilities as provided in §112.3(g) and have qualified oil-filled operational equipment on-site. Owners and operators of such facilities can use the alternative measures for oil-filled operational equipment described in §112.7(k) and self-certify the SPCC Plan. The owner or operator can choose to develop an oil spill contingency plan, provide a written commitment of manpower, equipment and materials and implement an inspection or monitoring program as an alternative to secondary containment for qualified oil-filled operational equipment. Since no impracticability determination is necessary for qualified oil-filled operational equipment, the owner or operator can self-certify his/her SPCC Plan and is not required to have a PE develop and certify the contingency plan for the qualified oil-filled operational equipment. The responsibility of preparing a contingency plan and identifying the necessary equipment, materials and manpower to implement the contingency plan would fall on the owner or operator of the qualified facility. For more information on qualified facilities, visit the EPA website at http://www.epa.gov/oem/content/spcc/spcc_qf.htm.

Tip – Generator sets

One commonly asked question is whether generator sets are considered oil-filled operational equipment.

No. Generator sets (gen sets) are a combination of oil-filled operational equipment and a bulk storage container. Lubrication systems on gen sets may be oil-filled operational equipment, but bulk storage tanks providing fuel for the generator typically are not oil-filled operational equipment.

Oil-Filled Manufacturing Equipment is not Oil-Filled Operational Equipment

The definition of oil-filled operational equipment does not include oil-filled manufacturing equipment (flow-through process). Oil-filled manufacturing equipment is inherently more complicated than oil-filled operational equipment because it typically involves a flow-through process and is commonly interconnected through piping. For example, oil-filled manufacturing equipment may receive a continuous supply of oil, in contrast to the static capacity of other, non-flow-through oil-filled equipment. Examples of oil-filled manufacturing equipment include, but are not limited to, process vessels, conveyances such as piping associated with a process, and equipment used in the alteration, processing or refining of crude oil and other non-petroleum oils, including animal fats and vegetable oils (71 FR 77276, December 26, 2006).

4.2.2 Alternative Measures for General Secondary Containment Requirement: Flowlines and Intra-facility Gathering Lines

"Flowlines" are typically found at oil production facilities. They are piping that transfer crude oil and well fluids from the wellhead to the tank battery where separation and treatment equipment are typically located. Flowlines may also connect a tank battery to an injection well. Depending on the size of the oil field, flowlines may range in diameter and run from hundreds of feet to miles between the wellheads and the tank batteries or primary separation operations.

> **§112.9(d)(3)**
>
> For flowlines and intra-facility gathering lines that are not provided with secondary containment in accordance with §112.7(c), unless you have submitted a response plan under §112.20, provide in your Plan the following:
>
> (i) An oil spill contingency plan following the provisions of part 109 of this chapter.
>
> (ii) A written commitment of manpower, equipment, and materials required to expeditiously control and remove any quantity of oil discharged that might be harmful.
>
> Note: The above text is an excerpt of the SPCC rule. Refer to 40 CFR part 112 for the full text of the rule.

The term ''gathering lines'' refers to piping or pipelines that transfer crude oil product between tank batteries, within or between facilities. Gathering lines often originate from an oil production facility's lease automatic custody transfer (LACT) unit, which transfers oil to other facilities involved in gathering, refining or pipeline transportation operations. EPA considers gathering lines subject to EPA's jurisdiction if they are located within the boundaries of an otherwise regulated SPCC/FRP facility (that is, intra-facility gathering lines) (73 FR 74274, December 5, 2008). See *Section 2.5.8* for a more detailed description of flowlines and intra-facility gathering lines, and the SPCC rule's applicability to each; note that intra-facility gathering lines subject to DOT requirements at 49 CFR parts 192 or 195 are exempt from the SPCC rule entirely.

Secondary containment is, in many cases, impracticable for flowlines and intra-facility gathering lines. For example, an oil production facility in a remote area may have many miles of flowlines and gathering lines, around which it would not be practicable to build permanent containment structures. It may not be possible to install secondary containment around flowlines running across a farmer's or rancher's fields since berms may become severe erosional features and can impede access to the fields by farm/ranch tractors and other equipment. Similarly, it may be impracticable to construct secondary containment around flowlines that run along a fence or county road due to space limitations or intrusions into a county's property or right-of-way. At unattended facilities, active secondary containment methods are not effective in meeting secondary containment requirements because there is limited capability to detect a discharge and deploy active measures in a timely fashion.

Therefore, §112.9(d)(3) provides an optional alternative to the general secondary containment requirements for flowlines and intra-facility gathering lines that are subject to the SPCC rule. In lieu of secondary containment, the facility owner or operator may implement an oil spill contingency plan in accordance with 40 CFR part 109 (*Criteria for State, Local and Regional Oil Removal Contingency Plans*) and have a written commitment of manpower, equipment, and materials required to expeditiously control and remove any quantity of oil discharged that may be harmful. These requirements are the same as those in §112.7(d) of the

rule, however, the Plan does not need to include an impracticability determination for each flowline and intra-facility gathering line.

The contingency plan required when secondary containment is not practicable for flowlines and intra-facility gathering lines should rely on strong maintenance, corrosion protection, testing, recordkeeping, and inspection procedures to prevent and quickly detect discharges from such lines. It should also ensure quick availability and deployment of response equipment. An effective flowline maintenance program is necessary to detect a discharge in a timely manner so that the oil discharge response operations described in the contingency plan may be implemented effectively.

Additionally, eliminating the requirement for secondary containment means that more prescriptive requirements are needed for discharge prevention to ensure the integrity of the primary containment of the pipe itself. The SPCC rule requires a performance-based program of flowline and intra-facility gathering line maintenance, in accordance with §112.9(d)(4), that addresses the facility owner or operator's procedures and must be documented in their SPCC Plan. See *Section 3.3.5* and *Chapter 7: Inspection, Evaluation, and Testing* (*Section 7.2.12*) for more information.

The complexity or simplicity of a facility's contingency plan is subject to good engineering practice as determined by the Plan certifier. EPA developed a model contingency plan (see *Appendix F* of this guidance). This model contingency plan is intended as an example and inspectors should only use it for this purpose.

4.3 Specific (Sized) Secondary Containment Requirements

While all parts of a regulated facility with potential for a discharge are, at a minimum, subject to the general secondary containment requirements of §112.7(c),[81] areas where certain types of containers, activities, or equipment are located may be subject to additional, more stringent containment requirements, including specifications for minimum capacity (see *Table 4-1*.) The SPCC rule specifies a required minimum size for secondary containment for the following areas:

- Loading/unloading racks;
- Bulk storage containers including mobile or portable containers (does not apply to mobile refuelers or other non-transportation-related tank trucks); and
- Production facility bulk storage containers, including tank batteries, separation, and treating equipment (e.g., produced water tanks).

The applicable requirements for each of these types of containers or equipment are discussed in more detail in *Section 4.7* of this chapter. In general, provisions for specific secondary containment require that the

[81] Note that the rule includes alternative provisions for certain equipment, in lieu of the general secondary containment requirements of §112.7(c).

chosen containment method be sized to contain the largest single oil compartment or container plus "sufficient freeboard" to contain precipitation,[82] as discussed in *Section 4.3.2* below.

EPA inspectors should note that the "largest single compartment" may consist of several containers that are permanently manifolded together. Permanently manifolded tanks are tanks that are designed, installed, or operated in such a manner that the multiple containers function as a single storage unit (67 FR 47122, July 17, 2002). Accordingly, the total capacity of manifolded containers is the design capacity standard for the sized secondary containment provisions (plus freeboard in certain cases).

4.3.1 Role of the EPA Inspector in Evaluating Secondary Containment Methods

The EPA inspector should evaluate whether the secondary containment system is adequate for the facility, and whether it is maintained to contain oil discharges to navigable waters or adjoining shorelines. This evaluation may include reviewing inspection reports and maintenance records. Some items that the inspector should look for include:

For a dike, berm, or other engineered secondary containment system:

- Capacity of the system to contain oil as determined in accordance with good engineering practice and the requirements of the rule;
- Cracks in containment system materials (e.g., concrete, liners, coatings, earthen materials);
- Discoloration;
- Presence of spilled or leaked material (standing liquid);
- Corrosion of the system;
- Erosion of the system;
- Operational status of drain valves or other drainage controls;
- Dike or berm permeability;
- Presence of debris;
- Level of precipitation in diked area and available capacity versus design capacity;
- Location/status of pipes, inlets, and drainage around and beneath containers;
- Excessive vegetation that may inhibit visual inspection and assessment of berm integrity;
- Large-rooted plants (e.g., shrubs, cacti, trees) that could affect the berm integrity;
- Holes or penetrations to the containment system created by burrowing animals; and
- Drainage records for rainwater discharges from containment areas.

[82] Does not apply to the loading and unloading rack secondary containment requirements.

For retention and drainage ponds:

- Capacity of the system to contain oil as determined in accordance with good engineering practice and the rule requirements;
- Erosion of the system;
- Discoloration;
- Design capacity versus available capacity;
- Presence of spilled or leaked liquid;
- Presence of debris;
- Cracks in containment system materials (e.g., concrete, liners, coatings, earthen materials);
- Stressed vegetation;
- Evidence of water seeps from the system; and
- Operational status of drain valves or other drainage controls.

While the rule does not require that secondary containment calculations be kept in the Plan, EPA strongly recommends that the facility owner or operator maintain the calculations such that if questions arise during an inspection, the calculations which serve as the basis for the capacity of the secondary containment system will be readily available for review by the EPA inspector. Industry guidance also recommends that facility owners or operators include any secondary containment capacity calculations and/ or design standards with the Plan. API Bulletin D16, ''Suggested Procedure for Development of a Spill Prevention Control and Countermeasure Plan,'' contains example calculations to which inspectors may refer (see Exhibit E of ''Suggested Procedure for Development of Spill Prevention Control and Countermeasure Plans,'' API Bulletin D16. Fifth Edition, April 2011).

Examples and blank worksheets are available in *Appendix H* of this guidance. These documents were developed to help qualified facility owner/operators to calculate secondary containment volume.[83] These worksheets address four specific scenarios and may not be valid for every facility:

- Single Vertical Cylindrical Tank Inside a Rectangular or Square Dike or Berm
- Multiple Horizontal Cylindrical Tanks Inside a Rectangular or Square Dike or Berm
- Rectangular or Square Remote Impoundment Structure
- Constructing New Secondary Containment

[83] Disclaimer: Please note that these are simplified calculations for qualified facilities that assume: 1) the secondary containment is designed with a flat floor; 2) the wall height is equal for all four walls; and 3) the corners of the secondary containment system are 90 degrees. Additionally, the calculations do not include displacement for support structures or foundations. For Professional Engineer (PE) certified Plans, the PE may need to account for site-specific conditions associated with the secondary containment structure which may require modifications to these sample calculations to ensure good engineering practice.

4.3.2 Sufficient Freeboard

The SPCC rule does not specifically define the term "sufficient freeboard," nor does it describe how to calculate this volume. The 1991 proposed amendment to the SPCC rule recommended the use of industry standards and data on 25-year storm events to determine the appropriate freeboard capacity. Numerous commenters on the 1991 proposal questioned the 25-year storm event recommendation and suggested alternatives, such as using 110 percent of storage tank capacity or using other characteristic storm events. EPA addressed these comments in the preamble to the 2002 amendments to the rule:

> *We believe that the proper standard of "sufficient freeboard" to contain precipitation is that amount necessary to contain precipitation from a 25-year, 24-hour storm event. That standard allows flexibility for varying climatic conditions. It is also the standard required for certain tank systems storing or treating hazardous waste. (67 FR 47117, July 17, 2002)*

However, the SPCC rule did not set this standard as a requirement for freeboard capacity. Therefore, the use of precipitation data from a 25-year, 24-hour storm event is not enforceable as a standard for containment freeboard. In the 2002 preamble, EPA further stated:

> *While we believe that the 25-year, 24-hour storm event standard is appropriate for most facilities and protective of the environment, we are not making it a rule standard because of the difficulty and expense for some facilities of securing recent information concerning such storm events at this time. (67 FR 47117, July 17, 2002)*

Ultimately, EPA determined that, for freeboard, "the proper method of secondary containment is a matter of engineering practice so [EPA does] not prescribe here any particular method" (67 FR 47101, July 17, 2002). However, where data are available, the facility owner/operator (and/or certifying PE) may want to consider the appropriateness of the 25-year, 24-hour storm event precipitation design criteria for containment freeboard.

A "110 percent of storage tank capacity" rule of thumb may be an acceptable design criterion in many situations, and aboveground storage tank regulations in many states require secondary containment to be sized to contain at least 110 percent of the volume of the largest tank. However, in some situations, 110 percent of storage tank capacity may not provide enough volume to contain precipitation from storm events. Some states require that facilities consider storm events when designing secondary containment structures, and in certain cases these requirements translate to more stringent sizing criteria than the 110 percent rule of thumb.

Other important factors may be considered in determining necessary secondary containment capacity. According to practices recommended by industry groups such as the American Petroleum Institute (API), these factors include:

- Local precipitation conditions (rainfall and/or snowfall);
- Height of the existing dike wall;

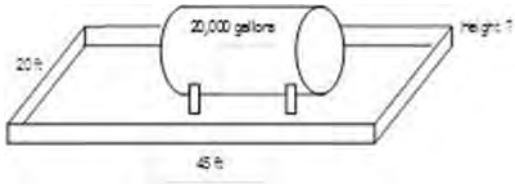
- Size of tank/container;
- Safety considerations; and
- Frequency of dike drainage and inspection.

The following examples (*Figure 4-5* and *Figure 4-6*) present secondary containment size calculations for hypothetical oil storage areas. The certifying PE (or owner/operator, in the case of qualified facilities) determines what volume constitutes sufficient freeboard for precipitation for secondary containment and should document in the Plan how the determination was made.

Figure 4-5: Sample calculation of containment size, using two design criteria.

The following example compares two different design criteria: one based on the volume of the tank and one based on precipitation.

Scenario:
A 20,000-gallon horizontal tank is placed within an engineered secondary containment structure, such as a concrete dike. The tank is 35 feet long by 10 feet in diameter. The secondary containment area provides a 5-foot buffer on all sides (i.e., dike dimensions are 45 feet x 20 feet.



Given the dike footprint, we want to determine the wall height necessary to provide sufficient freeboard for precipitation, based on (1) the tank storage capacity; (2) actual precipitation data. Several storm events in the recent past caused precipitation in amounts between 3.6 and 4.0 inches at this location, although greater amounts have also been reported in the past. *Note: The factor for converting cubic feet to gallons is 7.48 gallons/ft^3*.

1. Calculation of secondary containment capacity, based on a design criterion of 110% of tank storage capacity:

Containment surface area = 45 ft x 20 ft = 900 ft^2
Tank volume, based on 100% of tank capacity = 20,000 gallons
Tank volume, in cubic feet = 20,000 gallons / 7.48 gallons/ft^3 = 2,674 ft^3
Wall height that would contain the tank's volume = 2,674 ft^3 / 900 ft^2 = 2.97 ft

Containment capacity with freeboard, based on 110% of tank capacity = 22,000 gallons
Containment capacity, in cubic feet = 22,000 gallons / 7.48 gallons/ft^3 = 2,941 ft^3
Wall height equivalent to 110% of storage capacity = 2,941 ft^3 / 900 ft^2 = 3.27 feet
Height of freeboard = 3.27 ft - 2.97 ft = 0.3 ft = 3.6 inches

Therefore, a dike design based on a criterion of 110% of tank capacity provides a dike wall height of 3.27 feet.

2. Calculation of secondary containment capacity, based on rainfall criterion:

After a review of historical precipitation data for the vicinity of the facility, the PE determined that a 4.5 inch rain event is the most reasonable design criterion for this diked area.

Containment surface area = 45 ft x 20 ft = 900 ft^2
Tank volume, based on 100% of tank capacity = 20,000 gallons
Tank volume, in cubic feet = 20,000 gallons / 7.48 gallons/ft^3 = 2,674 ft^3
Wall height that would contain the tank's volume = 2,674 ft^3 / 900 ft^2 = 2.97 ft

The height of the dike would need to be 3.35 feet (2.97 ft + 4.5 in).

Therefore, a dike design based on a 4.5 inch rain event provides a dike wall height of 3.35 feet, or almost 1 inch higher than calculated using the 110% criterion.

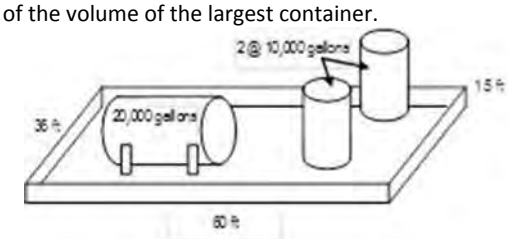
Conclusion:

As noted from the comparison of the two design criteria illustrated above, the dike heights are similar although not exactly the same. The adequacy of the secondary containment freeboard is ultimately an engineering determination made by the PE and certified in the Plan.

Figure 4-6: Sample secondary containment calculations, for multiple tanks in a containment area.

The EPA inspector has questioned the adequacy of the secondary containment based on the following scenario and wants to verify how much precipitation the dike area can hold and compare it to available precipitation data to determine if 112% is an adequate design criterion for this facility.

Scenario:
A 60 ft x 36 ft concrete dike surrounds one 20,000-gallon horizontal tank (10 ft diameter and 35 ft length) and two 10,000-gallon vertical tanks (each 10 ft diameter and 15 ft height). The dike walls are 18 inches (1.5 feet) tall. The SPCC Plan states that secondary containment is designed to hold 112% of the volume of the largest container.



Notes:

- *The factor for converting gallons to cubic feet is 7.48 gallons/ft^3.*
- *The volume displaced by a cylindrical vertical tank is the tank volume within the containment structure and is equal to the tank footprint multiplied by height of the concrete dike. The tank footprint is equal to $\pi D^2/4$, where D is the tank diameter.*

1. Calculate total dike capacity:

Total capacity of the concrete dike = length x width x height = 60 ft x 36 ft x 1.5 ft = 3,240 ft^3 = 24,235 gallons

2. Calculate net dike capacity, considering displacement from other tanks within the dike:

The total capacity of the concrete dike is reduced by the volume displaced by other tanks inside the containment structure. The displacement is:
= number of tanks x footprint x height of dike wall = 2 π (10 ft)^2 /4 x 1.5 ft = 235.6 ft^3 = 1,762 gallons

The net dike capacity, i.e., the volume that would be available in the event of a failure of the largest tank within the dike, is:
= Total volume - tank displacement = 24,235 - 1,762 = 22,473 gallons = 3,004 ft^3

3. Calculate the amount of available freeboard provided by the dike, given the net dike capacity:

The available freeboard volume is:
= Net dike capacity - volume of largest tank within the dike
= 22,473 - 20,000 = 2,473 gallons = 331 ft^3

This is equivalent, expressed in terms of the capacity of the largest tank, to:
= Net dike capacity/volume of largest tank within the dike
= 22,473 / 20,000 = 112%

This available freeboard volume provides a freeboard height:
= Available freeboard volume / dike surface area
= 331 ft^3 / (60 ft x 36 ft) = 0.15 ft ≈1.8 in

Therefore, this dike provides sufficient freeboard for 1.8 inches of precipitation.

Conclusion:

The EPA inspector should review the Plan and/or inquire about the precipitation event considered in determining that sufficient freeboard for precipitation is provided. The adequacy of the secondary containment freeboard is ultimately an engineering determination made by the PE and is certified in the Plan. This example serves only as a guide on doing the calculations for certain circumstances in which the inspector has concerns with the freeboard volume associated with the secondary containment design.

4.3.3 Role of the EPA Inspector in Evaluating Sufficient Freeboard

When reviewing an SPCC Plan, the EPA inspector should evaluate whether the size of secondary containment is adequate to meet the freeboard requirement. When examining the secondary containment measures for bulk storage containers, mobile or portable oil containers, and oil production facility bulk storage containers, the inspector should ensure that the Plan documents that the secondary containment can hold the entire capacity of the largest single container, plus sufficient freeboard to contain precipitation. Whatever method is used to calculate the amount of freeboard that is "sufficient" for the facility and container configuration should be documented in the Plan.

To determine whether secondary containment is sufficient, the EPA inspector may:

- Verify that the Plan specifies the capacity of secondary containment along with supporting documentation, such as calculations for comparing freeboard capacity to the volume of precipitation in an expected storm event.
  - If calculations are not included with the Plan, and the inspector suspects the secondary containment is inadequate, the inspector may request supporting documentation from the owner/operator.[84]
  - If diked area calculations appear inadequate, review local precipitation data such as data from airports or the National Weather Service,[85] as needed.
- Review operating procedures, storage tank design, and/or system controls for preventing inadvertent overfilling of oil storage tanks that could affect the available capacity of the secondary containment structure.
- Confirm that the secondary containment capacity can reasonably handle the contents of the largest tank on an *ongoing basis* (i.e., including during rain events).
- During the inspection, verify that the containment structures and equipment are maintained and that the SPCC Plan is properly implemented.

4.4 Issues Related to Secondary Containment Requirements

The following sections describe issues related to all secondary containment requirements, general and specific.

---

84 Industry guidance recommends that facility owners/operators include any secondary containment capacity calculations and/or design standards with the Plan. API Bulletin D16, "Suggested Procedure for Development of Spill Prevention Control and Countermeasure Plans," contains example calculations to which inspectors may refer.

85 National Weather Service, Hydrometeorological Design Studies Center, Current Precipitation Frequency Publications, available at http://www.nws.noaa.gov/oh/hdsc/currentpf.htm#N2.

4.4.1 Passive versus Active Measures of Secondary Containment

In some situations, permanent containment structures, such as dikes, may not be feasible (e.g., may cause pooling of liquids around electrical equipment which may present a hazard). Section 112.7(c) specifically allows for the use of active containment measures (countermeasures or spill response capability), which prevent a discharge to navigable waters or adjoining shorelines. Active containment measures are those that require deployment or other specific action by the owner or operator. These measures may be deployed either before the start of an activity involving the handling of oil, or in reaction to a discharge, so long as the active measure is designed to prevent an oil spill from reaching navigable water or adjoining shorelines. Passive measures are permanent installations and do not require deployment or action by the owner/operator.

Active measures (countermeasures) include, but are not limited to:

- **Placing a properly designed storm drain cover over a drain to contain a potential spill in an area where a transfer occurs, *prior* to the transfer activity.** Storm drains are normally kept uncovered; deployment of the drain cover prior to the transfer activity may be an acceptable active measure to prevent a discharge from reaching navigable waters or adjoining shorelines through the drainage system.

- **Placing a storm drain cover over a drain in reaction to a discharge, before the oil reaches the drain.** If deployment of a drain cover can *reliably* be achieved in time to prevent a discharge of oil from reaching navigable waters or adjoining shorelines, this may be an acceptable active measure. This method may be risky, however, and is subject to a good engineering judgment on what is realistically and reliably achievable, particularly under adverse circumstances.

- **Using spill kits in the event of an oil discharge.** The use of spill kits, strategically located and ready for deployment in the event of an oil discharge, may be an acceptable active measure, in certain circumstances, to prevent a spill from reaching navigable waters or adjoining shorelines. This method may be risky and is subject to good engineering judgment, considering the volume most likely expected to be discharged and proximity to navigable waters or adjoining shorelines.

- **Use of spill response capability (spill response teams) in the event of an oil discharge.** This method differs from activating an oil spill contingency plan (see §112.7(d)) because the response actions are specifically designed to contain an oil discharge *prior to* reaching navigable waters or adjoining shorelines. Such actions may include the emergency construction/deployment of dikes, curbing, diversionary structures, ponds, and other temporary containment methods (such as sorbent materials), so long as they can be implemented in time to prevent the spilled oil from reaching navigable waters or adjoining shorelines. This method may be risky and reliance on oil spill response capability for secondary containment is subject to good engineering judgment.

- **Closing a gate valve that controls drainage from an undiked area prior to a discharge.** If the gate valve is normally kept open, closing it before an activity that may result in an oil discharge may be an acceptable active measure to prevent a spill from reaching navigable waters or adjoining shorelines. Note that the rule requires that bypass valves for *diked areas* be sealed closed (§§112.8(c)(3)(i) and 112.12(c)(3)(i)).

Considerations in Selecting an Active Containment Measure

The use of active containment as a strategy to address discharges should be carefully evaluated. The efficacy of active containment measures to prevent a discharge depends on their technical effectiveness (e.g., mode of operation, absorption rate), placement and quantity, and timely deployment prior to or following a discharge. For discharges that occur only during attended or observed activities, such as those occurring during transfers, an active measure (e.g., sock, mat, other portable barrier, or land-based response capability) may be appropriate, provided that the measure is capable of containing the most likely volume of an oil discharge from a typical failure mode, and is timely and properly constructed/deployed. Ideally, in order to further reduce the potential for an oil discharge to reach navigable waters or adjoining shorelines, the active measure should be deployed prior to initiating the activity with potential for a discharge.

Tip – Active vs. passive containment measures

Active: The containment measure involves a certain action by facility personnel before or after the discharge occurs. These actions are also referred to as spill countermeasures.

Passive: The containment measure remains in place regardless of the facility operations and therefore does not require an action by facility personnel.

For certain active measures, however, such as the use of “kitty litter” or other sorbent material, it may be impractical to pre-deploy the measure. In such cases, the sorbent material should be readily available so that it can be used *immediately* after a spill occurs but before it can spread. Portable tanks can be equipped with a spill kit to be used in the event of a discharge during transfers. The spill kit should be sized, however, to effectively contain the volume of oil that could be discharged. Most commercially available spill kits are intended for relatively small volumes (up to approximately 150 gallons of oil).

Active containment measures can be used to satisfy the general secondary containment requirement when they are capable of containing the most likely discharge volume identified in the SPCC Plan. Elements to consider may include the capacity of the containment measure, effectiveness, timely implementation, and the availability of facility personnel and equipment to implement the active measure effectively. For example, a discharge of 600 gallons would require deploying more than 900 “high-capacity” sorbent pads (20 inches by 20 inches) since each pad absorbs less than 0.7 gallons of oil. The same spill volume would require nine sorbent blankets, each measuring 38 inches by 144 feet and weighing approximately 40 pounds. The rapid deployment of such response equipment and material would be difficult to achieve under most circumstances, particularly if only a few individuals are present when the discharge occurs, or during adverse conditions (e.g., rainfall, fire).

Using an active measure to meet the specific secondary containment requirement for a bulk storage container may be difficult because the containment system must be sized for the entire capacity of the bulk oil

storage container. Therefore, the use of active measures for larger oil containers may not be appropriate or in accordance with good engineering practice or sound industry standards.

In certain circumstances, sorbents, such as socks, booms, pads, or loose materials may be used to complement passive measures. For example, where berms around transfer areas are open on one side for access, and where the ground surface slopes away from the opening with no nearby drains, sorbent material may be effective in preventing small quantities of oil from escaping the bermed area in the event of a discharge.

The secondary containment approach implemented at a facility need not be "one-size-fits-all." Different approaches may be taken for the same activity at a given facility, depending on the material and location. For example, the SPCC Plan may specify that drain covers and sorbent material be pre-deployed prior to transfers of low viscosity oils in certain areas of a facility located in close proximity to drainage structures or navigable waters. For other areas and/or other products (e.g., highly viscous oils), the Plan may specify that sufficient spill response capability (spill response teams) are available for use in the event of a discharge, so long as personnel and equipment are available at the facility and these measures can be effectively implemented in a timely manner to prevent oil from reaching navigable waters or adjoining shorelines.

Evaluating the ability of active secondary containment measures deployed after a discharge to prevent oil from reaching navigable waters or adjoining shorelines involves considering the time it would take to discover the discharge, the time for the discharge to reach navigable waters or adjoining shorelines, and the time necessary to deploy the active secondary containment measure. For some active containment measures such as the use of sorbent materials, the amount of oil the secondary containment measure can effectively contain, including the potential impact of precipitation on sorption capacity, is also a critical factor. Good engineering practice would indicate that active secondary containment measures may be used to satisfy the general secondary containment requirements of §112.7(c) only in certain circumstances.

The use of an active measure containment strategy can be risky if not properly designed, evaluated and implemented. If an active measure fails to prevent an oil discharge from reaching navigable waters or adjoining shorelines, the owner or operator is liable for the discharge and cleanup, and is responsible for properly reporting it to the National Response Center. Furthermore, even when used to comply with §112.7(c), active measures should be limited to those situations where a PE has determined that the typical failure mode involves a small volume of oil. Generally, active containment measures are not appropriate for satisfying the specific containment requirements for a major container failure. Inspectors should closely review the SPCC Plan and evaluate the rationale, equipment and implementation of such a strategy, as in most cases, this would not be considered good engineering practice.

Deployment of Active Measures

Active measures are not appropriate for all situations with the potential for an oil discharge. As noted above, active measures often have limited absorption or containment capacity. Additionally, storage tanks, piping, and other containers pose a risk of discharge during off-hour periods when facility personnel are generally not on site or are too few in number to detect a discharge in a timely manner and deploy the containment measure(s) in order to prevent a discharge of oil to navigable waters or adjoining shorelines. Pre-

deployment of active measures in a "fixed" configuration may be problematic since sorbent materials or portable barriers are typically not engineered for long-term deployment, and their performance may be affected by precipitation, ultraviolet light degradation, or cold temperature. Moreover, in some cases, the deployment of an active measure can interfere with other systems; for example, by impeding the proper operation of drainage structures (e.g., drain cover). For these reasons, engineered structures (such as dikes and berms, curbing, spill diversion ponds, or similar systems) remain the most effective means of spill control and containment for oil storage containers.

The SPCC Plan must describe the procedures used to deploy the active measures, explain how the use of active measures is appropriate to the situation, and explain the methods for discharge discovery that will be used to determine when deployment of the active measures is appropriate (§112.7(a)(3)(iii) and (iv)). The Plan should, for instance, discuss whether active measures will be put in place before a potential discharge event (e.g., a boom placed around a vehicle before fueling activities begin) or whether the active measures will be deployed quickly after a spill occurs as a countermeasure (e.g., sorbents on hand and readily available). The Plan should describe the amount of materials available and the location where they are stored, and the manpower required to adequately deploy the material in a timely manner. Both the amount and location of materials should be determined based on good engineering practice, taking into consideration the potential volume of a discharge and the time necessary to deploy the measure to prevent a discharge to navigable waters or adjoining shorelines. Some of this information may already be described in other existing documents at the facility, in which case, these documents should be referenced in the SPCC Plan and be available at the time of an inspection.

Using Active Measures with Oil-Filled Operational Equipment

Oil-filled operational equipment (e.g., electrical transformers, capacitors, switches) poses unique challenges; permanent (passive) containment structures, such as dikes, may not always be feasible. Oil-filled operational equipment as defined in §112.2 is only subject to the general secondary containment provision, and the owner/operator may use the flexibility of active containment measures as described above. However, active containment measures may be risky because they require the ability to detect a discharge, and these measures must be implemented *effectively and in a timely manner to prevent oil from reaching navigable waters and adjoining shorelines,* as required by §112.7(a)(3)(iii) and (c). As provided in §112.7(k), owners and operators of facilities with eligible oil-filled operational equipment have the option to prepare an oil spill contingency plan and a written commitment of manpower, equipment, and materials to expeditiously control and remove any oil discharged that may be harmful, in lieu of general secondary containment, without having to make an individual impracticability determination as required in §112.7(d).

Role of the EPA Inspector in Evaluating the Use of Active Measures of Secondary Containment

Inspectors should carefully evaluate the use of active measures and determine if the equipment and personnel are available for deployment of this secondary containment method. The EPA inspector should inspect the facility to determine whether the active measures are appropriate for the facility – i.e., the inspector should note whether material storage locations are reasonable given the time necessary to deploy measures,

and whether the amount of available materials is sufficient to handle the anticipated discharge volume. In addition, the inspector should document whether the owner/operator of the facility is keeping the necessary records.

Upon EPA inspection, a facility owner/operator should be able to demonstrate that facility personnel are able to carry out the deployment procedure as written. The EPA inspector should verify that the facility's SPCC Plan contains the following items, and that items in the Plan are observed in the field and/or verified through discussions with facility personnel. Questions for the EPA inspector to consider in evaluating the adequacy of active measures are also provided below.

- Explanation showing why the use of active measures is appropriate.
  - What is the expected/most likely potential discharge volume, and is the active measure appropriately sized to contain the spill?
  - What is the discharge detection method and is it appropriate?
  - How much time is required to deploy the selected active measure?
  - Given these factors, is the active measure a reasonable approach?
- Detailed description of deployment procedures.
  - Will active measures be put in place before or after a spill occurs?
  - If measures are to be activated after a spill occurs, does the Plan describe the method of discharge detection?
  - Are the equipment and personnel available to deploy/implement the proposed active containment measure in an effective and timely manner to prevent oil from reaching navigable waters or adjoining shorelines?
  - Does the Plan identify drainage pathways and the appropriate deployment location(s) for the active measures?
- Description of all necessary materials and the location where they are stored (i.e., location of drain covers, spill kits, or other spill response equipment).
  - In cases where spill kits or sorbent materials are to be used, does the Plan describe the amount of materials available?
  - Are inventory and/or maintenance logs provided to ensure that spill response equipment/materials are currently in sufficient supply and in good working condition (i.e., not damaged, expired, or used up)?
  - Are the equipment/materials located such that personnel can realistically get to the equipment and deploy it quickly enough to prevent a discharge to navigable waters or adjoining shorelines? That is, are the material and equipment accessible (not locked, or a key is available), and are they located close enough to the potential source of discharge?

- Description of facility staff responsible for deploying active measures.
  - Are training records up to date?
  - Have the personnel involved in activities for which the active measures might be deployed been trained (e.g., are they familiar with the location and use of spill response materials, drainage conditions)?
  - Is there sufficiently trained facility staff present at all times to effectively deploy the measures in the event of a discharge?

Furthermore, the EPA inspector may review records and documentation such as:

- Personnel training records
- Drill records
- Deployment logs

The EPA inspector does not need to require the facility personnel to actually deploy the active measure (e.g., through a demonstration or drill) to show that the measure is adequate and can be deployed in a timely manner. However, the inspector may ask a series of questions in order to determine if the procedures for deploying an active measure are well understood.

4.4.2 "Sufficiently Impervious"

Section 112.7(c) states that the entire secondary containment system, "including walls and floor, must be capable of containing oil and must be constructed so that any discharge from a primary containment system ... will not escape containment before cleanup occurs." With respect to bulk storage containers at onshore facilities (except oil production facilities), §§112.8(c)(2) and 112.12(c)(2) state that diked areas must be "sufficiently impervious to contain oil." The purpose of the secondary containment requirement is to prevent discharges as described in §112.1(b); therefore, effective secondary containment methods must be able to contain oil until the oil is cleaned up.

The rule does not specify permeability, hydraulic conductivity, or retention time performance criteria for these provisions (i.e., "sufficiently impervious" does not necessarily mean *indefinitely* impervious). Instead, the owner/operator and/or the certifying PE have the flexibility to determine how best to design the containment system to prevent a discharge to navigable waters or adjoining shorelines. This determination is based on a good engineering practice evaluation of the facility configuration, product properties, and other site-specific conditions. For example, a sufficiently impervious retaining wall, dike, or berm, including the walls and floors, must be constructed so that any discharge from a primary containment system will not escape the secondary containment system before cleanup occurs and before the oil reaches navigable waters or adjoining shorelines (§§112.7(c), 112.8(c)(2) and 112.12(c)(2)). In other words, secondary containment structures such as dikes, berms and retaining walls can be considered sufficiently impervious as long as they allow for cleanup to occur in

time to prevent a discharge to navigable waters or adjoining shorelines. Ultimately, the determination of imperviousness should be verified by a PE and documented in the SPCC Plan.

The preamble to the 2002 SPCC rule amendments states that "a complete description of how secondary containment is designed, implemented, and maintained to meet the standard of sufficiently impervious is necessary" (67 FR 47102, July 17, 2002). Therefore, pursuant to §112.7(a)(3)(iii) and (c), the Plan should address how the secondary containment is designed to effectively contain oil until it is cleaned up. Control and/or removal of vegetation may be necessary to maintain the imperviousness of the secondary containment and to allow for the visual detection of discharges. The owner or operator should monitor the conditions of the secondary containment structure to ensure that it remains impervious to oil. Repairs of excavations or other penetrations through secondary containment need to be conducted in accordance with good engineering practice.

The earthen floor of a secondary containment system may be considered "capable of containing oil" until cleanup occurs, or "sufficiently impervious" if there is no subsurface conduit to navigable waters allowing the oil to reach navigable waters before it is cleaned up. Should oil reach navigable waters or adjoining shorelines, it is a reportable discharge under 40 CFR part 110. The suitability of earthen material for secondary containment systems may depend on the properties of both the product stored and the soil. For example, compacted local soil may be suitable to contain a viscous product, such as liquid asphalt cement, but may not be suitable to contain gasoline. Permeability through the wall (or wall-to-floor interface) of the structure may result in a discharge to navigable waters or adjoining shorelines and must be carefully evaluated.

In certain geographic locations, the native soil (e.g., clay) may be determined as sufficiently impervious. However, in many more instances good engineering practice would generally not allow the use of a facility's native soil alone as secondary containment when the soil is not homogenous. In fact, certain state requirements may restrict the use of soil as a means of secondary containment, and many state regulations explicitly forbid the discharge of oil on soil. Pennsylvania's Storage Tank and Spill Prevention Act, for example, requires that facilities take immediate steps to prevent injury from any discharge of a substance that has the potential to flow, be washed or fall into waters, and endanger downstream users. Pennsylvania's law requires that residual substances be removed within 15 days from the ground or affected waters. Discharges to soil and groundwater may violate other federal regulations (and violate Section 311(b)(3) of the Clean Water Act if an oil discharge to groundwater impacts a navigable water or adjoining shoreline). The EPA inspector should strongly urge facility owners and operators to investigate and comply with all state and local requirements. An inspector who notices potential violations of other statutes or regulations should contact the appropriate authorities for follow-up with the facility.

In summary, the owner/operator must base determinations of sufficiently impervious secondary containment design on good engineering practice and site-specific considerations and this must be documented in the Plan.

Role of the EPA Inspector in Evaluating "Sufficiently Impervious"

Like other technical aspects of the SPCC Plan, the determination that a facility's soil is sufficiently impervious must be made on a case-by-case basis by the certifying PE (or owner/operator, in the case of qualified facilities). The EPA inspector should determine whether the facility's secondary containment is sufficiently impervious, based on a review of the SPCC Plan, inspection reports, maintenance records, and an observation of site conditions. The EPA inspector may ask to see any calculations or engineering justifications (as applicable) used in determining levels of imperviousness; this information should be maintained with the Plan to facilitate the inspector's review. To evaluate whether secondary containment is sufficiently impervious, the EPA inspector may consider the following:

- Whether the SPCC Plan describes how secondary containment is designed, implemented, and maintained to be sufficiently impervious. The certification of the Plan's adequacy is the responsibility of the PE (or the owner or operator of a qualified facility) and a determination of sufficient imperviousness may be based strictly on geotechnical knowledge of soil classification and best engineering judgment. The inspector may review records of hydraulic conductivity tests, if such tests were conducted to ascertain the imperviousness of the secondary containment structure. The inspector may also review drainage records that are required to be kept by the facility owner/operator in accordance with §112.8(c)(3), §112.9(b)(1), or §112.12(c)(3). If, for example, facility personnel never drain the outdoor containment, then the inspector may pose follow-up questions to clarify how the facility removes precipitation after heavy rainfall, since lack of rainfall accumulation could indicate that the water is escaping the containment structure through the walls or floor.

- Procedures for how the owner/operator minimizes and evaluates the potential for corrosion of the bottom/bases of bulk storage containers that cannot be visually inspected. Corrosion of container bottom is addressed in part by integrity testing of bulk storage containers under §112.8(c)(6) or §112.12(c)(6). If a facility owner/operator cannot certify that the material under the container is sufficiently impervious (whether earthen or manmade), the inspector should consider:

  - Whether the inspection and integrity testing program in the Plan includes an internal inspection, in accordance with industry standards. The scope of this internal inspection should include the bottom plate. Since the bottom plate cannot be examined from the underside, the only inspection available is to assess the fitness of the bottom plate via an internal inspection. (See *Chapter 7: Inspection, Evaluation, and Testing* for more information on integrity testing.)
  - Whether the owner/operator of the facility has a system in place to detect oil discharges from a container bottom in order to commence cleanup before a discharge escapes the containment systems.

- Evidence of stained soil or stressed vegetation outside the containment area as well as at nearby outfalls or other areas affected by runoff from the secondary containment structure. For example, at onshore oil production facilities, there may be oil stains or white areas and white salt crystal deposits on the outside of berm walls and on the ground surface farther away from the berm. These deposits may indicate that oil and produced water has flowed through the secondary containment and that the structure may not be sufficiently impervious.

- How the secondary containment is constructed (materials and method of construction). The inspector should consider the type of soil (if soil is used). Floor and walls constructed of sandy material, for example, may not be appropriate to hold refined products such as gasoline. If earthen material is used, then it should have a high clay content and be properly compacted, not simply formed into a mound. Untreated cinder blocks used for containment should be closely evaluated by an inspector due to their porous nature.

- If a facility considers the earthen floor of a secondary containment system to be sufficiently impervious, the inspector should consider any underground pathway that could lead to navigable waters.

4.4.3 Facility Drainage (Onshore Facilities)

The facility drainage requirements of §§112.8(b) and 112.12(b) are design standards for secondary containment (not additional secondary containment requirements) and are therefore eligible for deviations that provide equivalent environmental protection in compliance with §112.7(a)(2) and as determined appropriate by a PE. *Chapter 3: Environmental Equivalence* discusses ways to evaluate whether facility drainage systems that deviate from the specified design standards are "environmentally equivalent" and comply with §112.7(a)(2) (see *Section 3.3.1*).

The following sections describe how the facility drainage provisions at §§112.8(b) and 112.12(b) relate to each other and to the secondary containment requirements.

Facility Drainage Control from Diked Areas

When a dike (the term as used here also includes other barrier methods such as berms, retaining walls, curbing, weirs, or booms) is used as the containment method to satisfy either general or specific secondary containment requirements, then facility drainage requirements also apply. The requirements for diked areas at onshore facilities (except oil production facilities) are found in §112.8(b)(1), 112.8(b)(2) (or §112.12(b)(1), and 112.12(b)(2)); for diked areas at onshore oil production facilities they are found in §112.9(b)(1). Drainage from diked storage areas can be accomplished by several means such as valves, manually activated pumps, or ejectors. If dikes are drained using valves, they must be of manual design to prevent an uncontrolled discharge outside of the dike, such as into a facility drainage system or effluent treatment system, except where facility systems are designed to control such a discharge (§§112.8(b)(1) and 112.12(b)(1)). Although not required by the rule, owners and operators should strongly consider locking valves controlling dike or remote impoundment areas, especially when they can be accessed by non-facility personnel.

For diked areas serving as secondary containment for bulk storage containers, §§112.8(c)(3) and 112.12(c)(3) require that storm water accumulations be inspected for the presence of oil and that records of the drainage events be maintained. Prior to draining these areas, accumulated oil on the rainwater must be removed and returned to storage or disposed of in accordance with legally approved methods.

Facility Drainage Control from Undiked Areas

When secondary containment requirements are addressed through facility drainage controls, such as culverting, gutters, ponds, or other drainage systems, the requirements in §112.8(b)(3) and (4), or §112.12(b)(3) and (4) apply. For example, a facility may

§§112.8(b) and 112.12(b) *Facility drainage*.

(1) Restrain drainage from diked storage areas by valves to prevent a discharge into the drainage system or facility effluent treatment system, except where facility systems are designed to control such discharge. You may empty diked areas by pumps or ejectors; however, you must manually activate these pumps or ejectors and must inspect the condition of the accumulation before starting, to ensure no oil will be discharged.

(2) Use valves of manual, open-and-closed design, for the drainage of diked areas. You may not use flapper-type drain valves to drain diked areas. If your facility drainage drains directly into a watercourse and not into an on-site wastewater treatment plant, you must inspect and may drain uncontaminated retained stormwater, as provided in paragraphs (c)(3)(ii), (iii), and (iv) of this section.

Note: The above text is an excerpt of the SPCC rule. Refer to 40 CFR part 112 for the full text of the rule.

§§112.8(c)(3) and 112.12(c)(3)

Not allow drainage of uncontaminated rainwater from the diked area into a storm drain or discharge of an effluent into an open watercourse, lake, or pond, bypassing the facility treatment system unless you:

(i) Normally keep the bypass valve sealed closed.

(ii) Inspect the retained rainwater to ensure that its presence will not cause a discharge as described in § 112.1(b).

(iii) Open the bypass valve and reseal it following drainage under responsible supervision; and

(iv) Keep adequate records of such events, for example, any records required under permits issued in accordance with §§ 122.41(j)(2) and 122.41(m)(3) of this chapter.

Note: The above text is an excerpt of the SPCC rule. Refer to 40 CFR part 112 for the full text of the rule.

choose to use the existing storm drainage system to meet secondary containment requirements by channeling discharged oil to a remote containment area to prevent a discharge to navigable waters or adjoining shorelines. The facility drainage system must be designed to flow into ponds, lagoons, or catchment basins designed to retain oil or return it to the facility. Catchment basins must not be located in areas subject to periodic flooding (§§112.8(b)(3) and 112.12(b)(3)).

Conversely, the owner or operator of a facility does not have to address the undiked area requirements of §112.8(b)(3) and (4) or §112.12(b)(3) and (4) if the facility does not use drainage systems to meet one of the secondary containment requirements in the SPCC rule. For example, if the SPCC Plan documents the use of an active containment measure (such as a combination of sorbents and a spill mat) that is effective to prevent a discharge to navigable waters or adjoining shorelines, then secondary containment has been provided and it is not necessary to alter drainage systems at the facility. The facility drainage system design requirements in §112.8(b)(3) and (4) or §112.12(b)(3) and (4) apply only when the facility uses these drainage systems to comply with the secondary containment provisions of the rule.

The EPA inspector should determine if the facility's documentation in the Plan identifies whether the final ponds, lagoons, or catchment basins are designed/sized to meet the appropriate general and/or specific secondary containment requirements. The following examples help to illustrate how to determine the appropriate size of the ponds, lagoons, or catchment basins:

- **General Secondary Containment.** A facility owner/operator may use a storm water drainage system that flows to a containment pond to address the general secondary containment requirements of §112.7(c) for a piece of operational equipment (including electrical oil-filled equipment). The secondary containment system must be designed to address the typical failure mode and to contain the volume of oil most likely to be discharged as determined according to good engineering practice and documented in the SPCC Plan (not necessarily a complete/major container failure).

- **Specific Secondary Containment.** If a facility owner/operator uses a storm water drainage system that flows to a catchment basin to comply with the specific secondary containment requirements for a bulk storage container, the secondary containment system must be designed to contain the capacity of the largest bulk storage container located inside the containment system (with appropriate freeboard for precipitation) as dictated by the rule's requirements in §§112.8(c)(2) or 112.12(c)(2). The specific secondary containment requirement is based on a worst case container failure in which the entire capacity of the container is discharged.

- **General and Specific Secondary Containment.** In a case where a drainage system to a final catchment basin is used to meet multiple secondary containment needs for the facility, including compliance with both general and specific secondary containment requirements, the system's design will need to meet the most stringent rule requirement (typically sized for the specific secondary containment requirement).

Oil Production Facility Drainage

Owners and operators of oil production facilities must close and seal drains on secondary containment systems associated with tank batteries and separation and treating areas (both dikes and other equivalent measures required under §112.7(c)(1)) at all times, except when draining uncontaminated rainwater (§112.9(b)(1)). Prior to drainage, the owner/operator must inspect the diked area and take action as provided in §112.8(c)(3)(ii), (iii), and (iv). If oil is present, then the owner/operator must remove accumulated oil on the rainwater and return it to storage or dispose of it in accordance with legally approved methods.

§112.9(b) Oil production facility drainage.

(1) At tank batteries and separation and treating areas where there is a reasonable possibility of a discharge as described in §112.1(b), close and seal at all times drains of dikes or drains of equivalent measures required under §112.7(c)(1), except when draining uncontaminated rainwater. Prior to drainage, you must inspect the diked area and take action as provided in § 112.8(c)(3)(ii), (iii), and (iv). You must remove accumulated oil on the rainwater and return it to storage or dispose of it in accordance with legally approved methods.

(2) Inspect at regularly scheduled intervals field drainage systems (such as drainage ditches or road ditches), and oil traps, sumps, or skimmers, for an accumulation of oil that may have resulted from any small discharge. You must promptly remove any accumulations of oil.

Note: The above text is an excerpt of the SPCC rule. Refer to 40 CFR part 112 for the full text of the rule.

Owners and operators of oil production facilities must also inspect field drainage systems (such as drainage ditches or road ditches), and oil traps, sumps, or skimmers at regularly scheduled intervals for an accumulation of oil that may have resulted from any small discharge and promptly remove any accumulations of oil from these systems. EPA inspectors should evaluate facility records to verify compliance with the drainage procedures described in §112.8(c)(3). Any storm water discharge records maintained at the facility in accordance with the NPDES requirements in §122.41(j)(2) or 122.41(m)(3) are acceptable to satisfy the recordkeeping requirements of §§112.8(c)(3)(iv) or 112.12(c)(3)(iv). Field observations may also shed light on compliance with the drainage provisions of the rule.

Role of the EPA Inspector in Evaluating Onshore Facility Drainage

The EPA inspector should review the facility's SPCC Plan to ensure that the drainage procedures are documented and records are maintained. The EPA inspector should also examine the facility to determine whether the drainage procedures are implemented as described in the SPCC Plan and whether they are appropriate for the facility. If a facility uses drainage systems to meet one or more secondary containment requirements, the EPA inspector should evaluate whether the final ponds, lagoons, or catchment basins are designed/sized in accordance with the appropriate general and/or specific secondary containment requirements. The EPA inspector should also evaluate the facility records to verify compliance with the drainage procedures described in §112.8(c)(3).

4.4.4 Man-made Structures

If an oil storage container at a regulated facility is located inside a building, the PE certifying the SPCC Plan may take into consideration the ability of the building walls and/or drainage systems to serve as secondary

containment. As described throughout this chapter, the SPCC regulation is performance-based and provides flexibility to the facility owner or operator in terms of how to design and implement secondary containment to provide adequate protection.

As described in *Section 4.3*, the regulation provides general design criteria for secondary containment of bulk storage containers by requiring that the containment system be sized to contain the capacity of the largest container, with freeboard for precipitation, as appropriate. The SPCC rule does not specify a volume amount to account for precipitation (e.g., 110 percent of capacity); instead it allows the facility owner or operator, or the PE certifying the Plan, to consider location-specific conditions, including the possibility that a bulk storage container is located indoors where precipitation is not a factor. When secondary containment is provided inside a building, freeboard calculations for precipitation are typically not applicable.

The SPCC rule also requires that the containment structure provided around bulk storage containers be sufficiently impervious to oil. Any indoor drainage system that leads directly to a storm sewer (discharging into a stream), a sanitary sewer (discharging into a Publicly Owned Treatment Works (POTW)), or otherwise directly into a waterbody may serve as a conduit for a discharge to navigable waters or adjoining shorelines. Therefore, the containment structure must not be equipped with open floor drains or an automated sump pump unless the drainage system has been purposefully equipped to treat any discharge (e.g., by use of an adequately sized, designed and maintained oil-water separator). Additionally, any doorways, windows, or other openings that would permit a discharge to flow out of the building must also be taken into consideration.

To the extent that an existing building structure meets the SPCC performance criteria for secondary containment, the owner/operator can consider such a building as an appropriate containment structure. In cases where the building walls are used for secondary containment, the calculation of the capacity of the secondary containment structure would need to consider the displacement by other containers, equipment, and items sharing the containment structure.

Where applicable, containers may be subject to the National Fire Protection Association's Flammable and Combustible Liquids Code (NFPA 30) in addition to the SPCC requirements. For containers located in buildings, NFPA 30 prescribes specific requirements to control fire hazards involving flammable or combustible liquids, particularly in the areas of design, construction, ventilation, and ultimately facility drainage. Specifically, NFPA 30 requires that curbs, scuppers, drains or similar features prevent the flow of liquids to adjacent buildings during emergencies, and includes provisions to handle water from fire protection systems. In the area of facility drainage, NFPA 30 requires that a facility be designed and operated to prevent the discharge of liquids to public waterways, public sewers, or adjoining property. Thus, if a facility is designed, constructed and maintained to applicable fire codes, such as NFPA 30, the building may serve as secondary containment under the SPCC rule.

4.4.5 Double-walled or Vaulted Tanks or Containers

A double-walled tank is essentially a tank within another tank, equipped with an interstitial (i.e., annular) space and constructed in accordance with industry standards. The inner tank serves as the primary oil storage container while the outer tank serves as secondary containment. The outer tank of a double-walled tank may provide adequate secondary containment for discharges resulting from leaks or ruptures of the entire

capacity of the inner storage tank. The term ''vaulted tank'' has been used to describe both double-walled tanks (especially those with a concrete outer shell) and tanks inside underground vaults, rooms, or crawl spaces. Double-walled or vaulted tanks are subject to secondary containment requirements.

In the case of vaulted tanks, the Plan preparer must determine whether the vault meets the requirements for secondary containment in §112.7(c). This determination should include an evaluation of drainage systems and of sumps or pumps which could cause a discharge of oil outside the vault. Industry standards for vaulted tanks often require the vaults to be liquid tight, which if sized correctly, may meet the secondary containment requirement. There might also be other examples of such alternative systems. (67 FR 47102, July 17, 2002).

EPA issued two memorandums to address how the secondary containment requirements of §112.7(c) apply to double-walled tanks. In the first memo, issued April 29, 1992,[86] EPA described that shop-fabricated aboveground double-walled tanks that meet certain industry construction standards, with capacities less than 12,000 gallons, installed and operated with protective measures such as overfill alarms, flow shutoff or restrictor devices, and constant monitoring of product transfers would generally comply with the secondary containment requirements of §112.7(c). As an alternative to the overfill prevention measures to contain discharges from a double-walled tank, active or passive measures of secondary containment may be used to contain overfills from tank vents that may occur during transfer operations.

The 1992 memo was later amended on August 9, 2002[87] to remove the 12,000 gallon tank capacity limitation and to discuss additional SPCC requirements that apply to double-walled tanks.

Shop-fabricated double-wall ASTs, regardless of size, may generally satisfy not only the secondary containment requirements of §112.7(c), but also the specific secondary containment requirements for sizing secondary containment for bulk storage containers found at §112.8(c)(2).[88] Double-walled tanks that store animal fats or vegetable oils may generally satisfy the secondary containment requirements of §112.12(c)(2).

However, please note that double-walled tanks with fittings or openings (e.g. a manway) located below the liquid

Tip – Transfers from double-walled tanks

A double-walled tank may have adequate containment for the bulk storage container; however it does not provide adequate secondary containment to address transfer-related overfills from the tank vent. Active secondary containment measures may be used to contain overfills from vents associated with transfer operations.

86 Memorandum, *Use of Alternative Secondary Containment Measures at Facilities Regulated under the Oil Pollution Prevention Regulation (40 CFR Part 112)*, OSWER 9360.8-37, Don R. Clay, OSWER Assistant Administrator, April 29, 1992.

87 Memorandum, *Use of Alternative Secondary Containment Measures at Facilities Regulated under the Oil Pollution Prevention Regulation (40 CFR Part 112)*, OSWER 9360.8-38, Marianne Lamont Horinko, OSWER Assistant Administrator, August 9, 2002.

88 Double-walled tanks typically do not require additional freeboard for precipitation when the interstice is not exposed to precipitation.

level of the container may require additional secondary containment to conform with industry standards and/or local codes. For example, NFPA 30 (paragraph 22.11) requires that piping connections be above the liquid level to conform to spill control requirements.

Summary of required elements from the double-walled tank memos:

The use of certain shop-built double-wall ASTs serve as an "equivalent" preventive system for purposes of the general secondary containment requirements of §112.7(c) when they include the following elements:

1) Containers are shop fabricated;
2) The inner tank is an Underwriter Laboratories (UL)-listed steel tank;
3) The outer tank is constructed in accordance with nationally accepted industry standards (e.g., API, STI, the American Concrete Institute);
4) Equipped with the following overfill prevention measures to contain overfills from tank vents:
   a) Overfill alarm and
   b) Automatic flow restrictor or flow shut-off; and
5) All product transfers are constantly monitored.

Alternative to Overfill Prevention Measures: As an alternative to the overfill prevention measure described in the fourth bullet above, the container may be equipped with either active or passive secondary containment methods to address the typical failure mode and the most likely quantity of oil that would be discharged from the tank's vents during during transfer operations.

Inspection Requirements for Double-walled Tanks

Section 112.8(c)(6) requires the owner or operator to conduct integrity testing on a regular schedule and whenever he makes repairs. The section also requires the owner or operator to frequently inspect the outside of the container for signs of deterioration, discharges, or accumulation of oil inside diked areas (for a double-walled tank, this inspection requirement applies to the inner tank). For more information on how to meet the inspection requirements for double-walled-tanks see *Chapter 7: Inspection, Evaluation, and Testing.*

§112.2

Repair means any work necessary to maintain or restore a container to a condition suitable for safe operation, other than that necessary for ordinary, day-to-day maintenance to maintain the functional integrity of the container and that does not weaken the container.

Note: The above text is an excerpt of the SPCC rule. Refer to 40 CFR part 112 for the full text of the rule.

Other Applicable Secondary Containment Requirements

While shop-fabricated double-wall ASTs may satisfy the requirements of §112.7(c) and §112.8(c)(2), such tanks, associated appurtenances/piping and transfer activities are also subject to other applicable SPCC requirements. For example, the facility owner or operator must satisfy §112.7(h) requirements for tank car and tank truck loading/unloading racks if he transfers oil in bulk to double-wall tanks from highway vehicles or railroad cars. If such transfers occur, where loading/unloading area drainage does not flow into a catchment basin or treatment facility designed to handle spills, a quick drainage system must be used. The

containment system must be designed to hold at least the maximum capacity of any single compartment of a tank car of tank truck loaded or unloaded at the facility. Transfer areas (those not associated with a loading/unloading rack) need to comply with the general secondary containment requirements in §112.7(c).

Additionally, any piping, equipment, or device not contained within a double-walled AST is subject to the general secondary containment requirements of §112.7(c). If a facility drainage system will be used to comply with secondary containment then the piping, equipment or device is also subject to requirements of §112.8(b) or §112.12(b).

4.5 Overview of the Impracticability Determination Provision

Although secondary containment systems are preferred, they may not always be practicable. If a PE determines that containment methods are "impracticable," alternative modes of protection to prevent and contain oil discharges are available. The SPCC rule provision found in §112.7(d) allows facility owners/operators to substitute other measures in place of secondary containment.

If an impracticability determination is made, the SPCC Plan must clearly describe why secondary containment measures are impracticable and how the alternative measures are implemented (§112.7(d)). See *Section 4.6* of this chapter for more information on the alternative measures.

The option of determining impracticability assumes that it is feasible to effectively and reliably implement an oil spill contingency plan. EPA inspectors should be aware that an impracticability determination may affect the applicability to the facility of the FRP requirements under 40 CFR part 112 subpart D. In addition, an impracticability determination may affect the calculation of the worst case discharge volume, which may impact the amount of resources required to respond to a worst case discharge scenario to comply with the FRP requirements.

§112.7(d)

Provided your Plan is certified by a licensed Professional Engineer under §112.3(d), or, in the case of a qualified facility that meets the criteria in §112.3(g), the relevant sections of your Plan are certified by a licensed Professional Engineer under §112.6(d), if you determine that the installation of any of the structures or pieces of equipment listed in paragraphs (c) and (h)(1) of this section, and §§112.8(c)(2), 112.8(c)(11), 112.9(c)(2), 112.10(c), 112.12(c)(2), and 112.12(c)(11), to prevent a discharge as described in 112.1(b) from any onshore or offshore facility is not practicable, you must clearly explain in your Plan why such measures are not practicable; for bulk storage containers, conduct both periodic integrity testing of the containers and periodic integrity and leak testing of the valves and piping; and, unless you have submitted a response plan under §112.20, provide in your Plan the following:

1) An oil spill contingency plan following the provisions of part 109 of this chapter.
2) A written commitment of manpower, equipment, and materials required to expeditiously control and remove any quantity of oil discharged that may be harmful.

Note: The above text is an excerpt of the SPCC rule. Refer to 40 CFR part 112 for the full text of the rule.

Only secondary containment requirements can be determined to be impracticable; for most other technical requirements, the rule provides flexibility to facility owners or operators to implement alternative measures that provide equivalent environmental protection (see *Chapter 3: Environmental Equivalence* for more information on the environmental equivalence provision).

Because the expertise of a trained professional is important in making site-specific impracticability determinations, owners or operators of Tier II qualified facilities (as described in §112.3(g)) who choose to self-certify their SPCC Plans in lieu of PE-certification cannot take advantage of the flexibility allowed by the impracticability provision, unless such determinations are reviewed and certified in writing by a PE (§112.6(b)(3)(ii) and 112.6(b)(4)). When secondary containment is determined to be impracticable in accordance with §112.7(d), the Plan must clearly explain why secondary containment measures are not practicable at the facility and provide the alternative measures required in §112.7(d) in lieu of secondary containment.

4.5.1 Meaning of "Impracticable"

The impracticability determination is intended to be used when a facility owner/operator cannot install secondary containment by any reasonable method. Considerations include space and geographical limitations, local zoning ordinances, fire codes, safety, or other good engineering practice reasons that would not allow for secondary containment (67 FR 47104, July 17, 2002). EPA clarified in a *Federal Register* notice that economic cost may be considered as one element in a decision on alternative methods, consistent with good engineering practice for the facility, but may not be the only determining factor in claiming impracticability (see text box "*Notice concerning certain issues pertaining to the July 2002 Spill Prevention, Control, and Countermeasure (SPCC) rule"* below). Each impracticability determination is site-specific and EPA inspectors should carefully evaluate the rationale for the impracticability determination described by the PE in the SPCC Plan.

Notice concerning certain issues pertaining to the July 2002 Spill Prevention, Control, and Countermeasure (SPCC) rule

The Agency did not intend with [preamble language at 67 FR 47104] to opine broadly on the role of costs in determinations of impracticability. Instead, the Agency intended to make the narrower point that secondary containment may not be considered impracticable solely because a contingency plan is cheaper. (This was the concern that was presented by the commenter to whom the Agency was responding.)

In addition, with respect to the emphasized language enumerating considerations for determinations of impracticability, the Agency did not intend to foreclose the consideration of other pertinent factors. In fact, in the response-to-comment document for the SPCC amendments rulemaking, the Agency stated that "... for certain facilities, secondary containment may not be practicable because of geographic limitations, local zoning ordinances, fire prevention standards, *or other good engineering practice reasons.*"

The above text is an excerpt from 69 FR 29728 (May 25, 2004).

4.6 Required Measures when Secondary Containment is Impracticable

Pursuant to §112.7(d), if secondary containment is impracticable for any area where secondary containment requirements apply, facility owners or operators must clearly explain in the SPCC Plan why such secondary containment is impracticable and implement additional requirements. The additional requirements are:

- Periodic integrity testing of bulk storage containers;

- Periodic integrity testing and leak testing of the valves and piping associated with bulk storage containers;
- An oil spill contingency plan prepared in accordance with the provisions of 40 CFR 109, unless the facility has submitted a Facility Response Plan (FRP) under §112.20; and
- A written commitment of manpower, equipment, and materials required to expeditiously control and remove any quantity of oil discharged that may be harmful.

This section describes these additional requirements.

4.6.1 Integrity Testing of Bulk Storage Containers

When a facility owner or operator shows that secondary containment around a bulk storage container is impracticable, he or she must conduct periodic integrity testing of the container (§112.7(d)). Integrity testing is any means to measure the strength (structural soundness) of the container shell, bottom, and/or floor to contain oil. Integrity testing must be done in accordance with good engineering practice, and consider applicable industry standards. For a thorough discussion of integrity testing, see *Chapter 7: Inspection, Evaluation, and Testing*. *Chapter 7* describes the scope and frequency of inspections and tests, considering industry standards and the characteristics of the container. When there is no secondary containment around a container, good engineering practice would suggest a more stringent integrity testing schedule than would be required for a container if secondary containment were in place. Although the SPCC rule does not incorporate specific inspection frequency, certain industry standards require more frequent and/or more intensive inspection of containers when they do not have secondary containment.[89]

It should be noted that if an impracticability determination is made for bulk storage containers located at an oil production facility, the containers are subject to integrity testing under §112.7(d) and integrity testing should be in accordance with applicable industry standards and good engineering practice.

The EPA inspector should verify that the Plan describes the integrity testing of bulk storage containers, in particular for those containers for which secondary containment is impracticable. The EPA inspector should also review testing records to ensure that the inspection program is implemented as described.

4.6.2 Periodic Integrity and Leak Testing of the Valves and Piping

When the facility owner or operator determines that secondary containment for a bulk storage container is impracticable, he/she must also perform periodic integrity and leak testing of valves and piping associated with the container for which secondary containment is impracticable (§112.7(d)). As the PE establishes the periodic integrity testing for the bulk storage container, he will also determine the minimal

[89] For example, the Steel Tank Institute's "Standard for the Inspection of Aboveground Storage Tanks," SP001, 5th Edition, Steel Tank Institute, September 2011 (summarized in *Chapter 7: Inspection, Evaluation, and Testing*) requires more frequent inspections of tanks that do not have adequate secondary containment.

elements of the integrity and leak testing program needed for the for the valves and piping and identify what portion of piping to include in the program.

Leak testing determines the liquid tightness of valves and piping and whether they may discharge oil. Leak testing should be performed in accordance with appropriate industry standards. *Chapter 7: Inspection, Evaluation, and Testing* provides an overview of integrity and leak testing of valves and piping. As for integrity testing, good engineering practice may suggest a more stringent leak testing schedule than would be required if secondary containment were in place. The scope of this integrity and leak testing program is a matter of good engineering practice and should be clearly described in the SPCC Plan.

Tip – Valves and piping

Valves and piping are subject to additional periodic integrity testing and leak testing requirements when a PE determines that secondary containment is impracticable for an associated bulk storage container.

The EPA inspector should verify that the Plan describes the type and scope of integrity and leak testing for valves and piping associated with bulk storage containers for which secondary containment is impracticable. The inspector should also review testing records to ensure that the testing program is implemented as described and is in accordance with the scope of the testing program described by the PE in the Plan.

4.6.3 Oil Spill Contingency Plan and Written Commitment of Resources

Unless he or she has submitted a Facility Response Plan under §112.20, an owner or operator who determines that secondary containment is impracticable must include with the SPCC Plan an oil spill contingency plan following the provisions of 40 CFR part 109 and a written commitment of manpower, equipment, and materials required to expeditiously control and remove any quantity of oil that may be harmful (§112.7(d)).

The requirements for the content of contingency plans are given in 40 CFR part 109 (Criteria for State, Local, and Regional Oil Removal Contingency Plans). The elements of the contingency plan are outlined in §109.5, and include:

- Definition of the authorities, responsibilities, and duties of all persons, organizations, or agencies that are to be involved or could be involved in planning or directing oil removal operations;
- Establishment of notification procedures for the purpose of early detection and timely notification of an oil discharge;
- Provisions to ensure that full resource capability is known and can be committed during an oil discharge situation;
- Provisions for well-defined and specific actions to be taken after discovery and notification of an oil discharge; and
- Specific and well-defined procedures to facilitate recovery of damages and enforcement measures as provided for by state and local statutes and ordinances.

Refer to the model contingency plan in *Appendix F* of this guidance for an example contingency plan prepared in compliance with the SPCC rule and 40 CFR part 109.

A ''written commitment'' of manpower, equipment, and materials means either a written contract or other written documentation showing that the owner/operator has made provision for items needed for response purposes. According to 40 CFR 109.5, the commitment includes:

- Identification and inventory of applicable equipment, materials, and supplies that are available locally and regionally;
- An estimate of the equipment, materials, and supplies that would be required to remove the maximum oil discharge to be anticipated;
- Development of agreements and arrangements in advance of an oil discharge for the acquisition of equipment, materials, and supplies to be used in responding to such a discharge;
- Provisions for well-defined and specific actions to be taken after discovery and notification of an oil discharge, including specification of an oil discharge response operating team consisting of trained, prepared, and available operating personnel;
- Pre-designation of a properly qualified oil discharge response coordinator who is charged with the responsibility and delegated commensurate authority for directing and coordinating response operations and who knows how to request assistance from federal authorities operating under current national and regional contingency plans;
- A preplanned location for an oil discharge response operations center and a reliable communications system for directing the coordinated overall response actions;
- Provisions for varying degrees of response effort depending on the severity of the oil discharge; and
- Specification of the order of priority in which the various water uses are to be protected where more than one water use may be adversely affected as a result of an oil discharge and where response operations may not be adequate to protect all uses. (67 FR 47105, July 17, 2002).

Note that a facility owner/operator does not need to develop a separate contingency plan and written commitment of manpower, equipment, and materials for each individual impracticability determination. A single plan, describing how the elements apply to each area where secondary containment is impracticable, will suffice. Additionally, the elements required under §112.7(d) may be integrated into other contingency plans that already may be in place at the facility, such as those developed pursuant to other federal or state requirements.

For a contingency plan to satisfy the requirements of §112.7(d), the owner or operator of a facility must be able to activate and implement the contingency plan immediately upon detection of a discharge. As part of evaluating the adequacy of the contingency plan developed to satisfy requirements of §112.7(d), the EPA

inspector should consider the time it takes facility personnel to detect and mitigate a discharge to navigable waters or adjoining shorelines. For example, at an unmanned facility (or during periods of time when a facility is unattended), effective implementation of the contingency plan may involve enhanced discharge detection methods such as more frequent facility visits and inspections, or the use of spill detection equipment.

4.6.4 Difference between Contingency Plans and Active Containment Measures

Note that active containment measures are used to meet *secondary containment requirements*, and contingency plans are used to meet *the requirement in §112.7(d) when an impracticability determination is made*. There is a subtle but important difference between active containment measures (i.e., countermeasures, including land-based response capability) and an oil spill contingency plan as described in §112.7(d). Active containment measures (as opposed to passive containment measures – i.e., permanent structures) require deployment or other action; they are put in place prior to or immediately upon discovery of an oil discharge. The purpose of active containment measures is to contain an oil discharge before it reaches navigable waters or adjoining shorelines. These measures should be designed to prevent discharges from leaving the facility boundaries.

A contingency plan, for SPCC purposes, is a detailed oil spill response plan developed when any form of secondary containment is determined to be impracticable. It addresses controlling, containing, and recovering an oil discharge in quantities that may be harmful to navigable waters or adjoining shorelines. The purpose of a contingency plan should be both to outline response capability or countermeasures to limit the quantity of a discharge reaching navigable waters or adjoining shorelines (if possible), and to address *response to a discharge of oil that has reached navigable waters or adjoining shorelines*. Thus, active containment measures can be part of a contingency plan and every effort should be made to control the oil discharge before it reaches navigable waters or adjoining shorelines.

Tip – Active containment measures vs. Contingency Plans

Active containment measure is used to describe any land-based response capability that is deployed or implemented immediately upon discovery of a discharge before the discharge reaches navigable waters or adjoining shorelines.

Contingency Plan is used to describe measures for controlling, containing, and recovering oil that has been discharged into or upon navigable waters or adjoining shorelines in such quantities as may be harmful.

4.6.5 FRP Implications for Impracticability Determinations

When a facility owner/operator determines that secondary containment is impracticable, he must also determine how this affects applicability of the Facility Response Plan (FRP) rule requirements under 40 CFR part 112.20 and 112.21 for the facility. The facility owner/operator may need to either prepare an FRP or revise an FRP to address how a lack of adequate secondary containment affects the worst case discharge planning volume for the facility.

Facility Not Previously Subject to FRP

If a facility is not subject to the FRP rule, then the owner or operator must determine if an impracticability determination will cause the facility to meet the following FRP applicability criterion:

> *The facility's total oil storage capacity is greater than or equal to one million gallons and it does not have secondary containment for each aboveground storage area sufficiently large to contain the capacity of the largest aboveground oil storage tank within each storage area plus sufficient freeboard to allow for precipitation (see §112.20(f)(1)(ii)(A)).*

If so, then the facility could reasonably be expected to cause substantial harm to the environment by discharging oil into or on navigable waters or adjoining shorelines and is now subject to the FRP requirements under §§112.20 and 112.21. The owner or operator must prepare and submit an FRP to the EPA Regional Administrator (RA) in accordance with §112.20(a)(2).

Even when the total facility capacity is less than one million gallons, the EPA RA may determine that a facility is a "substantial harm" facility and require the owner or operator to prepare and submit an FRP. The RA may consider a lack of secondary containment as a criterion to require an FRP for a facility in accordance with §112.20(f)(2).

Once an FRP is received, the EPA RA will review the plan to determine whether a facility could, because of its location, reasonably be expected to cause significant and substantial harm to the environment by discharging oil into or on navigable waters or adjoining shorelines (§112.20(c)). The EPA RA will review the "significant and substantial harm" facility FRP, require amendments (as applicable), and approve any response plan that meets the FRP rule requirements.

Aboveground oil storage tanks without adequate secondary containment will also factor into the calculation of the worst case discharge planning volume for the facility, which has implications for the quantity of response resources (by contract or other means) required under the FRP rule (see Appendices D and E of 40 CFR 112).

Facility Previously FRP-subject

If a facility was previously subject to the FRP requirements and then makes a determination of impracticability, the owner or operator of the facility must consider the implications of that change on the FRP. The owner or operator will need to recalculate the worst case discharge planning volume to address aboveground oil storage tanks without adequate secondary containment as well as determine sufficient response resources to respond to the worst case discharge in accordance with Appendix E.

The owner or operator must revise and resubmit portions of the FRP within 60 days of a facility change that materially may affect the response to a worst case discharge and submit a revised FRP to the EPA RA (§112.20(d)(1)). A lack of adequate secondary containment may also influence the RA to determine that the facility could reasonably be expected to cause significant and substantial harm to the environment by discharging oil into or on navigable waters or adjoining shorelines.

4.6.6 Role of the EPA Inspector in Reviewing Impracticability Determinations

Determinations of impracticability must be reviewed by the PE certifying the Plan in accordance with §112.3(d) or §112.6(b)(4) to ensure that they are consistent with good engineering practice. The EPA inspector should verify that the Plan has been certified by a PE and that the additional measures specified in §112.7(d) are documented in the Plan, as explained below.

By certifying a Plan, or a portion of a Plan, a PE attests that it has been prepared in accordance with good engineering practice, that it meets the requirements of 40 CFR part 112, and that it is adequate for the facility. Thus, if impracticability determinations and the corresponding alternative measures and contingency plan have been reviewed by the certifying PE and are properly documented, they should generally be considered acceptable by regional EPA inspectors.

However, if an impracticability determination and/or the additional required measures appear to be at odds with recognized industry standards, do not meet the overall objective of oil spill response/prevention, or appear to be inadequate for the facility, appropriate follow-up action may be warranted. In this case, the EPA inspector should clearly document the concerns (including photographs and drawings of the facility configuration, flow direction, and proximity to navigable waters) to assist RA review and follow-up. This may include requesting additional information from the facility owner or operator to justify the impracticability determination, the adequacy of the contingency plan, or determine compliance with other requirements of §112.7(d). The EPA inspector should also assess how the lack of adequate secondary containment impacts FRP applicability or worst case discharge planning for the facility (see *Section 4.6.5*).

A PE making an impracticability determination should have considered, to the extent possible, all reasonably appropriate options for secondary containment. The documentation presented in support of the impracticability determination should discuss the reasons why various secondary containment options are impracticable. The documentation must demonstrate the reasoning used to determine why secondary containment is impracticable, rather than provide an exhaustive evaluation of all potentially available types of secondary containment.

The example below (see *Figure 4-7*) describes an inadequate impracticability determination. The supporting discussion provided in the example does not provide a sufficient discussion of the reasons why a concrete dike is not practicable. It also fails to address, even in general terms, whether means of secondary containment other than a concrete dike may be practicable (e.g., remote impoundment, drainage systems, or active measures). Finally, the discussion does not provide information on the measures that are provided in lieu of secondary containment and how the facility intends to implement the contingency plan, commit manpower and equipment to respond, and perform the required testing on the bulk storage containers and associated piping and appurtenances. Refer to §112.7(c) and (d) for a list of available secondary containment options as well as the alternative measures required in the SPCC Plan when an impracticability determination is made.

Figure 4-7: Example of inadequate impracticability determination: Bulk Storage Containers

Bulk Storage Tanks – 40 CFR 112.8(c)(2)

XYZ Oil has determined that secondary containment is impracticable for the two bulk storage tanks located to the east of the maintenance building. There is not sufficient space to build a concrete dike because of the proximity to the property line. XYZ Oil is therefore implementing a contingency plan for this portion of the facility.

For comparison, the following example (see *Figure 4-8*) provides an adequate impracticability determination. The supporting discussion provided in the example clearly explains why various methods of secondary containment measures are not practicable, and documents the measures that the facility has implemented in lieu of secondary containment. Additionally, the PE explains the additional equipment/procedures that will be implemented to compensate for the lack of adequate secondary containment. These additional measures would typically provide an EPA inspector with assurance that a facility will be able to address oil discharges using a contingency plan (and ensure its timely implementation).

Figure 4-8: Example of adequate impracticability determination: Bulk Storage Containers

Bulk Storage Tanks – 40 CFR 112.8(c)(2)

XYZ Oil has determined that secondary containment is impracticable for the two bulk storage tanks located to the east of the maintenance building. There is not sufficient space to accommodate a dike or berm with the required containment capacity due to minimum setbacks and maximum dike height. A dike or berm with the required capacity would either encroach on the neighbor's property and/or exceed a 6-feet safe wall height (Occupational Safety and Health Administration (OSHA) Flammable and combustible liquids regulation, 29 CFR 1910.106). The facility also lacks the space necessary for remote impoundment. Other measures listed under §112.7(c) such as the use of sorbents would not be a reliable and effective means of secondary containment since the volumes involved may exceed the sorbent capacity.

The tanks are currently in good condition and do not need to be replaced. However, tanks of double-wall design may be considered as potential replacement in the future. The existing tanks have been equipped with a leak detection device to aid with the discovery of an oil discharge. The containers, due to a lack of containment, are going to be subject to a more aggressive integrity testing program than required by the governing standard (see Section 2.7 of the SPCC Plan, Integrity Testing, for details). Finally, the tanks are equipped with an overfill system and automatic shutdown leak detection to prevent overfills.

Because secondary containment for these two bulk storage tanks is impracticable, XYZ Oil has provided in this SPCC Plan the additional elements required under 40 CFR 112.7(d), namely:

- Periodic integrity testing of bulk storage containers, and periodic integrity and leak testing of valves and piping (see Section 2.7 of the SPCC Plan).
- A written commitment of manpower, equipment, and materials required to expeditiously control and remove any quantity of oil discharged that may be harmful (see Appendix F of the SPCC Plan).
- An Oil Spill Contingency Plan following the provisions of 40 CFR part 109 (see Appendix G of the SPCC Plan).

In addition to verifying that the SPCC Plan clearly describes the reason why secondary containment measures are not practicable and documents the implementation of the additional measures required in §112.7(d), the EPA inspector should verify that:

- The facility's contingency plan can be implemented as written;
- The equipment for response is available;
- The commitment of manpower, equipment, and materials is documented;
- The contingency plan describes the location of drainage systems, containment deployment locations, and oil collection areas (including recovered oil storage capability);
- There is a process in place to detect a discharge and implement the contingency plan at an unmanned facility;
- There are procedures for early detection of oil discharges that enables timely contingency plan implementation;
- There is a defined set of response actions; and
- The contingency plan meets all the criteria of §109.5.

Figure 4-9 provides a checklist that an EPA inspector can review to verify that all the criteria of §109.5 are included in a facility's oil spill contingency plan. The EPA inspector may also refer to the checklist included in *Figure 4-13* at the end of this chapter when identifying and reviewing technical rule requirements that are eligible for the impracticability provision.

Figure 4-9: Checklist of required components of state, local, and regional oil removal contingency plans. Please refer to the complete text of 40 CFR §109.5.

109.5–Development and implementation criteria for state, local, and regional oil removal contingency plans*	Yes	No
Definition of the authorities, responsibilities and duties of all persons, organizations or agencies which are to be involved in planning or directing oil removal operations.	☐	☐
Establishment of notification procedures for the purpose of early detection and timely notification of an oil discharge including:		
(1) The identification of critical water use areas to facilitate the reporting of and response to oil discharges.	☐	☐
(2) A current list of names, telephone numbers and addresses of the responsible persons (with alternates) and organizations to be notified when an oil discharge is discovered.	☐	☐
(3) Provisions for access to a reliable communications system for timely notification of an oil discharge, and the capability of interconnection with the communications systems established under related oil removal contingency plans, particularly State and National plans (e.g., NCP).	☐	☐
(4) An established, prearranged procedure for requesting assistance during a major disaster or when the situation exceeds the response capability of the State, local or regional authority.	☐	☐
Provisions to assure that full resource capability is known and can be committed during an oil discharge situation including:		
(5) The identification and inventory of applicable equipment, materials and supplies which are available locally and regionally.	☐	☐
(6) An estimate of the equipment, materials and supplies which would be required to remove the maximum oil discharge to be anticipated.	☐	☐
(7) Development of agreements and arrangements in advance of an oil discharge for the acquisition of equipment, materials and supplies to be used in responding to such a discharge.	☐	☐
Provisions for well-defined and specific actions to be taken after discovery and notification of an oil discharge including:		
(8) Specification of an oil discharge response operating team consisting of trained, prepared and available operating personnel.	☐	☐
(9) Predesignation of a properly qualified oil discharge response coordinator who is charged with the responsibility and delegated commensurate authority for directing and coordinating response operations and who knows how to request assistance from Federal authorities operating under existing national and regional contingency plans.	☐	☐
(10) A preplanned location for an oil discharge response operations center and a reliable communications system for directing the coordinated overall response operations.	☐	☐
(11) Provisions for varying degrees of response effort depending on the severity of the oil discharge.	☐	☐
(12) Specification of the order of priority in which the various water uses are to be protected where more than one water use may be adversely affected as a result of an oil discharge and where response operations may not be adequate to protect all uses.	☐	☐
Specific and well defined procedures to facilitate recovery of damages and enforcement measures as provided for by State and local statutes and ordinances.	☐	☐

* The contingency plan should be consistent with all applicable state and local plans, Area Contingency Plans, and the National Contingency Plan (NCP).

4.7 Selected Issues Related to Secondary Containment and Impracticability Determinations

Section 112.7(d) lists the provisions of the SPCC rule for which facility owners or operators may determine impracticability. Discussed below are commonly raised issues related to secondary containment requirements for various types of equipment and areas at a facility, and the use of impracticability determinations.

4.7.1 Piping (General Secondary Containment Requirement, §112.7(c))

Discharge reports from the Emergency Response Notification System (ERNS) suggest that discharges from valves, piping, flowlines, and appurtenances are much more common than catastrophic tank failure or discharges from tanks (67 FR 47124, July 17, 2002). To prevent a discharge to navigable waters or adjoining shorelines, the SPCC rule requires that all piping (including buried piping) comply with the general secondary containment requirements contained in §112.7(c).[90]

In many cases, secondary containment for piping will be possible. Nevertheless, §112.7(c) provides flexibility in the method of secondary containment: active containment measures including land-based response capability, sorbent materials, drainage systems, and other equipment are acceptable. Section 112.7(c) does not prescribe a specific containment size for piping; however, the secondary containment must be designed to address a typical failure mode for the piping and most likely quantity of oil discharged. The SPCC Plan should describe the expected sources of a discharge from piping systems, maximum flow rate, duration of a discharge, and discharge detection capability at the facility taking into consideration the specific features of the facility and operation. Calculations for each piping system may not be practical at large facilities due to the large number and complexity of the piping; instead, more general assumptions specific to the conditions at the individual facility may be appropriate as long as they are well documented in the Plan. The EPA inspector should ensure that the secondary containment method for piping is described in the SPCC Plan and that the PE has certified that the method is appropriate for the facility according to good engineering practice. In the case of a qualified facility, the owner or operator would certify that the method is appropriate for the facility in accordance with accepted and sound industry practices and standards. If active containment measures are selected, the facility personnel should be able to demonstrate that they can identify a discharge in a timely manner (e.g., a leak detection method) and effectively deploy these measures to contain a potential spill before it reaches navigable waters or adjoining shorelines.

Secondary containment may not always be practicable for piping. If secondary containment is not practicable, then the facility owner/operator may make an impracticability determination and comply with the alternative regulatory requirements described in §112.7(d), which includes developing an oil spill contingency plan. In order for a contingency plan to be effective, discharges must be detected in a timely manner. For

[90] The owner/operator of an oil production facility may either, comply with the general secondary containment requirements of §112.7(c) for flowlines and intra-facility gathering lines or develop a contingency plan and a written commitment of manpower, equipment and materials in accordance with §112.9(d)(3).

example, good engineering practice may require that unattended facilities where secondary containment is impracticable be inspected more frequently than would be required at a typical facility where secondary containment is provided. The SPCC Plan may include other procedures, testing and or equipment to aid in the timely implementation of a contingency plan and/or overall oil spill prevention. This may include, but is not limited to, aggressive pipe integrity management/testing procedures, leak detection equipment and enhanced corrosion protection. If it is not feasible to effectively and reliably implement a contingency plan and the facility does not meet the applicability criteria under the Facility Response Plan (FRP) requirements in §112.20, then owners/operators must determine how to comply with the applicable secondary containment requirements in §112.7(c).

4.7.2 Loading or Unloading Area (or Transfer Area) (General Secondary Containment Requirement, §112.7(c))

All areas with the potential for a discharge as described in §112.1(b) are subject to the general secondary containment provision, §112.7(c). These areas may include loading/unloading areas (also referred to as transfer areas), piping, mobile refuelers, and may include other areas of a facility where oil is present. A transfer operation is one in which oil is moved from or into some form of transportation, storage, equipment, or other device, into or from some other or similar form of transportation, such as a pipeline, truck, tank car, or other storage, equipment, or device (67 FR 47130, July 17, 2002). Loading or unloading areas where oil is transferred but no loading/unloading rack (as defined in §112.2) is present are subject to §112.7(c), and thus appropriate secondary containment and/or diversionary structures to prevent a discharge to navigable waters or adjoining shorelines are required. The SPCC rule does not require specifically sized containment for transfer areas; however, containment capacity must be based on the typical failure mode and most likely quantity of oil that would be discharged.

The general secondary containment requirement at §112.7(c) applies to both loading and unloading areas. Examples of activities that occur within transfer areas include, but are not limited to:

- Unloading oil from a truck to a heating oil tank;
- Loading oil into a vehicle from a dispenser; and
- Transferring crude oil from an oil production tank battery into tank trucks.

Secondary containment may be either active or passive in design and take into consideration the specific features of the facility and operation or activity. Specific features of different loading/unloading operations include the hardware, procedures, and personnel who are able to take action to limit the volume of a discharge. The determination of adequate general secondary containment volume must consider the typical failure mode and the most likely quantity of oil that would discharge as a result of that failure:

- **Typical Failure Mode**
  - **Identify the source and the mechanism of failure.** These could include a failed hose connection; improper transfer equipment connection or disconnection; pump, valve, flange or pipe fitting leak; or overfill of a container. Determining the typical failure mode would be based on the type of transfer operation, equipment, and procedures, facility experience and spill history, potential for human error, etc.
- **Most Likely Quantity of Oil Discharged.** This factor is based on the **reasonably expected** rate of discharge and duration of the discharge.
  - **The reasonably expected rate of discharge.** This factor will depend on the typical mode of failure. It may be equal to the maximum rate of transfer, e.g., when an improperly connected transfer hose connection separates, or the expected leakage rate, e.g., from a pump, pipe flange, pipe fitting, or hose valve.
  - **The ability to detect and react to the discharge.** This factor will depend on the availability of monitoring instrumentation for prompt detection of a discharge and/or the proximity of personnel to detect and respond to the discharge. The ability to detect a discharge is critical for the implementation of active containment measures.
  - **The reasonably expected duration of the discharge.** This factor may depend on the accessibility of manual or automatic shutdown mechanisms, the proximity of qualified personnel to the operation, and other factors that may limit the duration of a discharge.

After identifying the typical failure mode for each transfer area and the most likely quantity of oil that would be discharged, the facility owner/operator can determine the appropriate type of secondary containment (i.e., active or passive). To determine if active containment measures are appropriate to address the most likely discharge quantity, the owner/operator must determine the time it would take a discharge to impact navigable waters or adjoining shorelines. This factor will depend on the proximity to waterways and storm drains, and the slope of the ground surface between the loading area and the waterway or drain. The SPCC Plan must describe the type of secondary containment and, for active containment measures, clearly outline the procedures, equipment, and personnel necessary to implement this containment strategy.

Additionally, a number of other factors may also affect the appropriate volume for secondary containment at loading and unloading areas, such as the variable rate of transfer; the ability to control a discharge from a breached container, if such a breach is reasonably expected to occur; the availability of personnel in close proximity to the operations and the necessary time to respond; the presence or absence of monitoring instrumentation to detect a discharge; the type and location of valving that may affect the probable time needed to stop the discharge; and the presence or absence of automatic valve actuators. These are a few examples of the factors that a PE may want to consider when reviewing the adequacy of secondary containment systems at a facility. The EPA inspector may consider the same factors when assessing the adequacy of secondary containment.

An example calculation for secondary containment capacity in accordance with §112.7(c), based on these considerations, is provided in *Figure 4-10*. Note that the calculation of a most-likely discharge is often a site-specific determination that must be in accordance with good engineering practice.

Figure 4-10: Sample calculation of appropriate general secondary containment capacity at a transfer area.

Scenario: A fuel truck is loading oil into a heating oil tank at a regulated facility, with an attendant present throughout the operation.

Details:

- The truck is loading at a rate of 150 gallons per minute.
- The typical failure mode expected is a ruptured hose connection.
- A shutoff valve, present on the loading line, and the pump control are accessible to the attendant.
- An evaluation determines that the discharge will not impede the attendant's access to the shutoff valve and pump control. The attendant can safely shut down the pump and close the valve within 10 seconds of the hose connection rupture, based on past experience under similar circumstances; 15 seconds is assumed to be a conservative estimate of the response time.

Calculations:

With a flow rate of 150 gal/min and a reaction time of 15 seconds, the most likely discharge is calculated to be 37.5 gallons:

[(150 gal/min) x (1 min/60 sec) x (15 sec)] = 37.5 gallons

Conclusion:

Secondary containment volume should be at least 37.5 gallons. A larger volume for secondary containment would be needed if time required to safely close the shutoff valve takes longer than 15 seconds.

To determine if an active containment measure would be appropriate then the owner or operator also needs to consider the time it would take the discharge to impact navigable waters or adjoining shorelines.

Secondary containment structures, such as dikes or berms, may not be appropriate in areas where vehicles continuously need access; however, curbing, drainage systems, active containment measures, or a combination of these systems can adequately fulfill the secondary containment requirements of §112.7(c). A facility owner or operator may implement methods for secondary containment other than dikes or berms. For example, a transfer truck loading area at an onshore oil production facility may be designed to drain discharges away to a topographically lower area using a crescent or eyebrow-shaped berm. In certain situations, secondary containment at transfer areas may be impracticable due to geographic limitations, fire codes, etc. In these cases, owners/operators may determine that secondary containment is impracticable in accordance with §112.7(d), and must clearly explain the reasons why secondary containment is not practicable and comply with the alternative regulatory requirements.

4.7.3 Loading/Unloading Rack (Specific Secondary Containment Requirements, §112.7(h)(1))

Section 112.7(h) applies to areas at regulated facilities where traditional loading/unloading racks for tank cars and tank trucks are located. EPA inspectors should evaluate compliance with the requirements of §112.7(h) for equipment that meets the definition of "loading/unloading rack" as found in §112.2.

§112.2

Loading/unloading rack means a fixed structure (such as a platform, gangway) necessary for loading or unloading a tank truck or tank car, which is located at a facility subject to the requirements of this part. A loading/unloading rack includes a loading or unloading arm, and may include any combination of the following: piping assemblages, valves, pumps, shut-off devices, overfill sensors, or personnel safety devices.

Note: The above text is an excerpt of the SPCC rule. Refer to 40 CFR part 112 for the full text of the rule.

A loading/unloading arm is a critical component of a loading/unloading rack. A loading/unloading arm is typically a movable piping assembly that may include fixed piping or a combination of fixed and flexible piping, typically with at least one swivel joint (that is, at least two articulated parts that are connected in such a way that relative movement is feasible to transfer product via top or bottom loading/unloading to a tank truck or tank car). However, certain loading/unloading arm configurations present at loading racks may include a loading/unloading arm that is a combination of flexible piping (hoses) and rigid piping without a swivel joint. In this case, a swivel joint is not present on the loading arm because flexible piping is attached directly to the rigid piping of the loading arm and the flexible hose provides the movement needed to conduct loading or unloading operations in lieu of the swivel joint.

§112.7(h) – Facility tank car and tank truck loading/unloading rack (excluding offshore facilities).

(1) Where loading/unloading rack drainage does not flow into a catchment basin or treatment facility designed to handle discharges, use a quick drainage system for tank car or tank truck loading and unloading racks. You must design any containment system to hold at least the maximum capacity of any single compartment of a tank car or tank truck loaded or unloaded at the facility.

Note: The above text is an excerpt of the SPCC rule. Refer to 40 CFR part 112 for the full text of the rule.

In developing the definition in §112.2, EPA considered existing definitions of the term ''loading rack'' and related terms, as found in industry, federal, state, or international references, and reviewed various types of equipment considered components of loading racks (*see* 72 FR 58378, October 15, 2007). This definition does not include simple loading or unloading configurations, but rather only includes the associated equipment and structures associated with loading/unloading arms as part of a rack. Equipment present at a loading/unloading area where a pipe stand connects to a tank car or tank truck via a flexible hose is not a loading/unloading rack because there is no loading or unloading arm. Because some top and bottom loading/unloading racks are made up of a combination of steel loading arms connected by flexible hosing, the presence of flexible hoses on oil transfer equipment should not be used as an indicator of whether the equipment meets the definition of loading/unloading rack.

Section 112.7(h)(1) requires a sized secondary containment system: the containment must hold at least the maximum capacity of any single compartment of a tank car or tank truck loaded or unloaded at the facility.

However, the SPCC rule does not require that secondary containment for loading/unloading racks be designed to include freeboard for precipitation. When drainage from the areas surrounding a loading/unloading rack do not flow into a catchment basin or treatment facility designed to handle discharges, facility owners and operators must use a quick drainage system (§112.7(h)(1)). A "quick drainage system" is a device that drains oil away from the loading/unloading area to some means of secondary containment or returns the oil to the facility.

Loading and unloading activities that take place beyond the rack area are not subject to the requirements of §112.7(h), but are subject, where applicable, to the general secondary containment requirements of §112.7(c). Loading/unloading racks can be located at any type of facility; however, loading/unloading racks are not typically found at farms or oil production facilities. Oil transfers to or from oil storage containers at farms and oil production facilities where no loading rack is present are subject to the general secondary containment requirement. For more information on these requirements, see Section 4.7.2, Transfer Areas.

Figure 4-11 and *Figure 4-12* illustrate how SPCC secondary containment requirements apply at two facilities with loading/unloading areas and with equipment that meet the definition of loading/unloading rack. In *Figure 4-11*, the facility has two separate and distinct areas for transfer activities. One is a tank truck unloading area and the other includes a tank truck loading rack. The unloading area contains no rack structure, so the secondary containment requirements of §112.7(c) apply. The requirements of §112.7(h) apply to the area surrounding the loading rack. As highlighted by this example, the presence of a loading rack at one location of a facility does not subject other loading or unloading areas in a separate part of the facility to the requirements of §112.7(h).

In *Figure 4-12*, the tank truck loading rack and unloading area are co-located. In this situation, the more stringent secondary containment provision applies; therefore, the area is subject to the sized secondary containment requirements of §112.7(h)(1).

In certain situations, the sized secondary containment requirements of §112.7(h)(1) for loading/unloading racks may be impracticable due to geographic limitations, fire codes, etc. In these cases, the owner or operator may determine that secondary containment is impracticable as provided in §112.7(d). Under that provision, the SPCC Plan must clearly explain the reasons why secondary containment is not practicable, and comply with the alternative regulatory requirements.

Letter to Petroleum Marketers Association of America

"[T]he Agency does not interpret §112.7(h) to apply beyond activities and/or equipment associated with tank car and tank truck loading/unloading racks. Therefore, loading and unloading activities that take place beyond the rack area would not be subject to the requirements of 40 CFR §112.7(h) (but, of course, would be subject, where applicable, to the general containment requirements of 40 CFR §112.7(c))."

The above text is an excerpt from a letter to Daniel Gilligan, President, Petroleum Marketers Association of America, from Marianne Lamont Horinko, Assistant Administrator, EPA, May 25, 2004. Found at www.epa.gov/oilspill/pdfs/PMAA_letter.pdf.

Figure 4-11: Facility with separate unloading area and loading rack. The tank unloading area is subject to §112.7(c). The tank truck loading rack is subject to §112.7(h)(1).

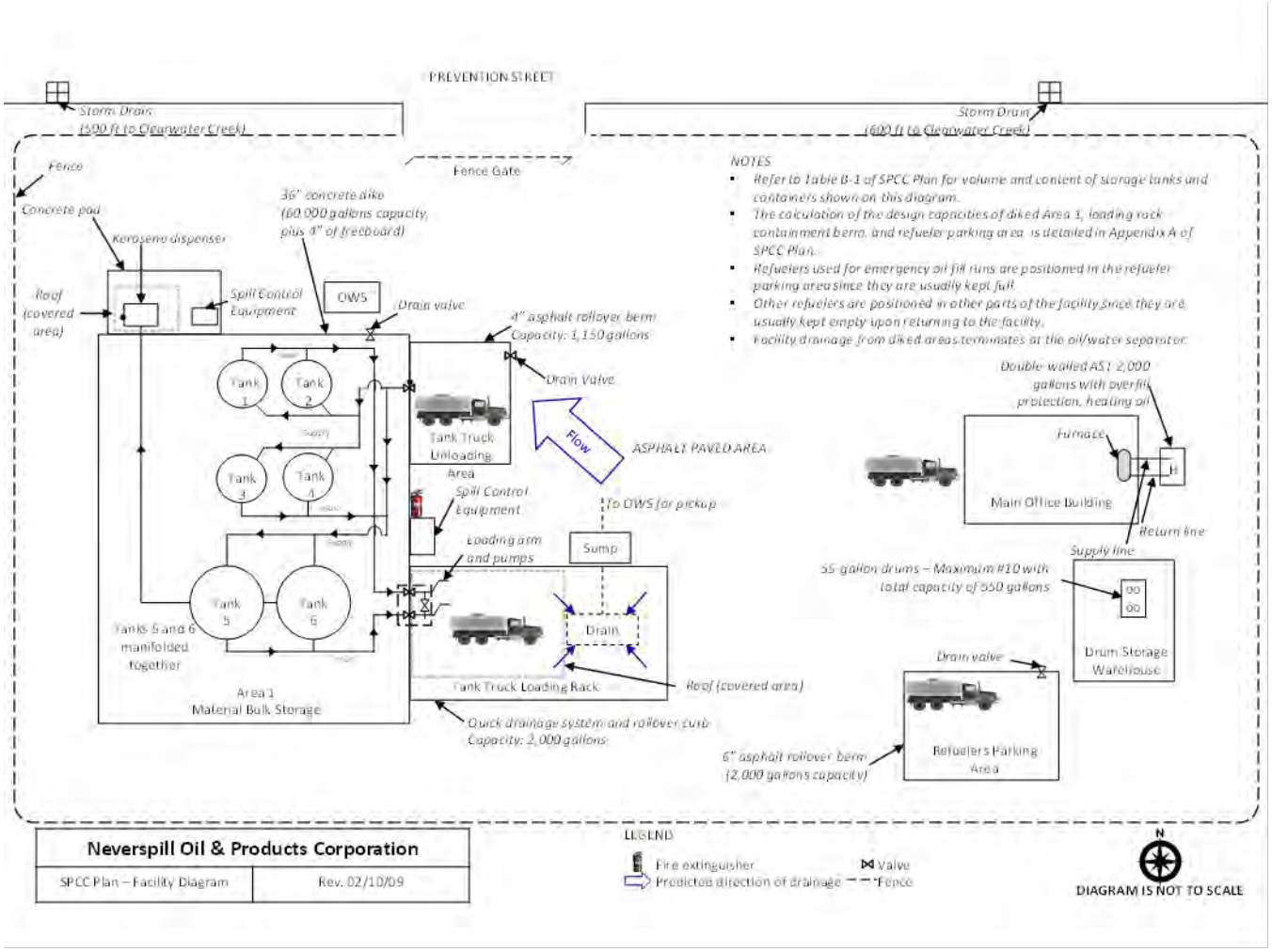
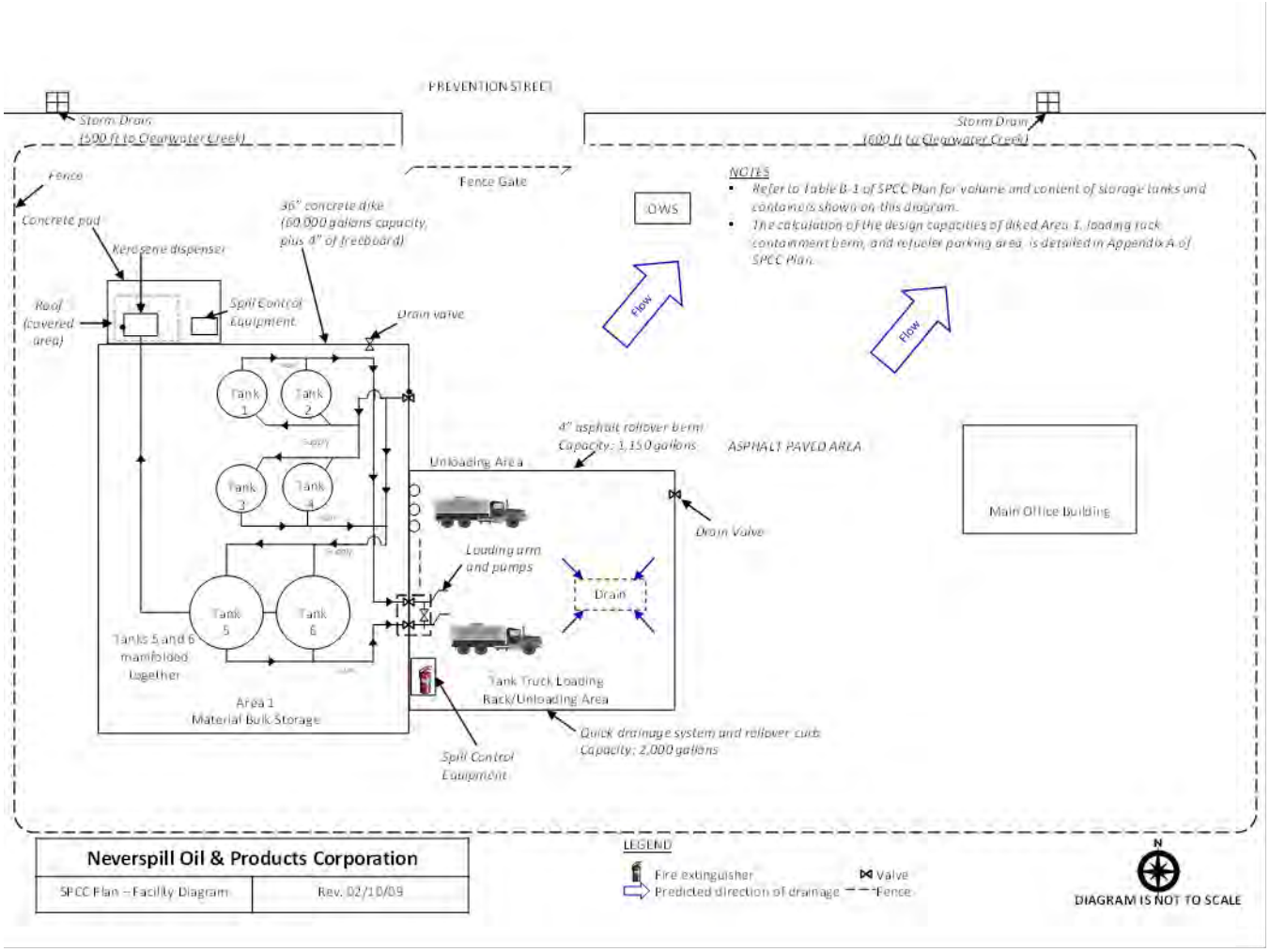


Figure 4-12: Facility with co-located unloading area and loading rack. This containment area is designed to meet the more stringent §112.7(h)(1) provision.



4.7.4 Onshore Bulk Storage Container (Specific Secondary Containment Requirements, §112.8(c)(2) and §112.12(c)(2))

Under the SPCC rule, a bulk storage container is any container used to store oil with a capacity of 55 gallons or more (§§112.1(d)(5) and 112.2). Bulk storage containers are used for purposes including, but not limited to, the storage of oil prior to use, while being used, or prior to further distribution in commerce. Oil-filled pieces of electrical, operating, or manufacturing equipment are not considered bulk storage containers.

Bulk storage containers at a regulated facility (except mobile refuelers and other non-transportation-related tank trucks) must comply with the specific (sized) secondary containment requirements of §112.8(c)(2).[91]

[91] The specific secondary containment requirements for bulk storage containers do not apply to oil-filled equipment (though they are subject to the general secondary containment requirements of §112.7(c). Certain oil-filled operational equipment may

For bulk storage containers, secondary containment must be designed to hold the entire capacity of the largest single container and sufficient freeboard[92] to contain precipitation. Secondary containment is required for all facilities with bulk storage containers, large or small, attended or unattended.

Section 112.8(c)(2) considers the use of dikes, containment curbs, and pits as secondary containment methods, or allows an alternative system consisting of a drainage trench enclosure that must be arranged so that any discharge will terminate and be safely confined in a facility catchment basin or holding pond. Dikes contain oil in the immediate vicinity of the storage container, whereas remote impoundment drains discharge to an area located away from the container. Examples of design considerations and requirements for these types of containment are set forth in the National Fire Protection Association (NFPA) 30 Flammable and Combustible Liquids Code.[93]

Diked areas must be sufficiently impervious to contain discharged oil. The purpose of the ''sufficiently impervious'' standard is to prevent discharges as described in §112.1(b) by ensuring that diked areas can contain oil and are sufficiently impervious to prevent such discharges (67 FR 47117; July 17, 2002). For more information on sufficiently impervious secondary containment see *Section 4.4.2*.

§§112.8(c)(2) and 112.12(c)(2)

Construct all bulk storage container installations (except mobile refuelers and other non-transportation-related tank trucks) so that you provide a secondary means of containment for the entire capacity of the largest single container and sufficient freeboard to contain precipitation. You must ensure that diked areas are sufficiently impervious to contain discharged oil. Dikes, containment curbs, and pits are commonly employed for this purpose. You may also use an alternative system consisting of a drainage trench enclosure that must be arranged so that any discharge will terminate and be safely confined in a facility catchment basin or holding pond.

Note: The above text is an excerpt of the SPCC rule. Refer to 40 CFR part 112 for the full text of the rule.

An owner or operator may determine that secondary containment is impracticable under §112.7(d), when he or the PE certifying the Plan, determines that it is not practicable to design a secondary containment system that can hold the capacity of the largest single container plus sufficient freeboard. If secondary containment is determined to be impracticable, the EPA inspector should verify that the SPCC Plan clearly explains why secondary containment is not practicable, and that the facility is complying with the alternative regulatory requirements, such as conducting both periodic integrity testing of the containers and periodic integrity and leak testing of the valves and piping (§112.7(d)). For further information on the alternative regulatory requirements in §112.7(d), see *Section 4.6*.

---

qualify for alternative requirements in lieu of secondary containment in accordance with §112.7(k).

92 For more information on sufficient freeboard, see the discussion in Section 4.3.2 of this chapter.

93 For more information on NFPA, visit their website at www.nfpa.org.

4.7.5 Mobile/Portable Containers (Except for Mobile Refuelers and Other Non-Transportation-related Tank Trucks) (Specific Secondary Containment Requirements, §§112.8(c)(11) and 112.12(c)(11))

Mobile or portable oil storage containers with a capacity to store 55 gallons or more of oil and operating exclusively within the confines of a non-transportation-related facility are regulated under the SPCC rule. With the exception of mobile refuelers and other non-transportation related tank trucks, such containers must comply with the secondary containment requirements of §112.8(c)(11) (or §112.12(c)(11) in the case of a facility that stores or handles animal fats or vegetable oils).

Examples of mobile portable containers include, but are not limited to, 55-gallon drums, skid tanks, totes, and intermediate bulk containers (IBCs).

According to §§112.8(c)(11) and 112.12(c)(11), mobile or portable containers (excluding mobile refuelers and other non-transportation-related tank trucks) must be positioned or located to prevent a discharge as described in §112.1(b). The provision requires that the secondary containment be sized to hold the capacity of the largest single compartment or container with sufficient freeboard to contain precipitation.

The appropriate containment methods for mobile containers may vary depending on the activity in which the container is engaged at a given time. Thus, secondary containment requirements may be met differently depending upon the type of operation being performed, as described below.

§§112.8(c)(11) and 112.12(c)(11)

Position or locate mobile or portable oil storage containers to prevent a discharge as described in §112.1(b). Except for Mobile facilitys and other non-transportation-related tank trucks, you must furnish a secondary means of containment, such as a dike or catchment basin, sufficient to contain the capacity of the largest single compartment or container with sufficient freeboard to contain precipitation.

Note: The above text is an excerpt of the SPCC rule. Refer to 40 CFR part 112 for the full text of the rule.

When mobile containers, such as drums, skids, and totes, are in a stationary mode, the requirements of §§112.8(c)(11) and 112.12(c)(11)[94] may be met through the use of permanent secondary containment methods, such as dikes, curbing, drainage systems, and catchment basins. In order to comply with this requirement, an owner/operator may designate an area of the facility in which to locate mobile containers when not in use. This area must be designed, following good engineering practices, to hold the capacity of the largest single compartment or container with sufficient freeboard to contain precipitation. The area designated for mobile portable containers must be identified on the facility diagram[95] provided within the SPCC Plan (§112.7(a)(3)).

While in use, mobile containers, such as drums, skids, and totes, must also comply with the requirements of §112.8(c)(11) or §112.12(c)(11) according to good engineering practice and the areas where the containers are used must be marked on the facility diagram. For these types of containers, the EPA inspector should verify that the secondary containment methods are appropriate to prevent a discharge to navigable waters or adjoining shorelines. For example, an oil-filled drum positioned for use at a construction site must be

[94] Mobile/portable containers at Tier I qualified facilities are subject to §112.6(a)(3)(ii) in lieu of §§112.8(c)(11) and 112.12(c)(11).

[95] Tier I qualified facilities are not subject to the facility diagram requirement in §112.7(a)(3).

equipped with secondary containment sized in accordance with §112.8(c)(11). The facility owner or operator may determine that it is impracticable to provide sized secondary containment in accordance with §112.8(c)(11), when the container is in use at the facility, or the general containment of §112.7(c), pursuant to §112.7(d). If so, then the SPCC Plan must properly explain why secondary containment is impracticable, and document the implementation of the alternative regulatory requirements of §112.7(d).

4.7.6 Mobile Refuelers and other Non-transportation-Related Tank Trucks (General Secondary Containment Requirement, §112.7(c))

When mobile containers meet the definition of mobile refuelers, in §112.2, then they are excluded from the sized secondary containment requirements for bulk storage containers. Providing sized secondary containment for vehicles that move frequently within a non-transportation-related facility to perform refueling operations can raise safety and security concerns (71 FR 77266, December 26, 2006). However, the general secondary containment requirements at §112.7(c) still apply. Furthermore, since mobile refuelers are a subset of bulk storage containers, the other provisions of §§112.8(c) and 112.12(c) also still apply.

§112.2

Mobile refueler means a bulk storage container onboard a vehicle or towed, that is designed or used solely to store and transport fuel for transfer into or from an aircraft, motor vehicle, locomotive, vessel, ground service equipment, or other oil storage container.

Note: The above text is an excerpt of the SPCC rule. Refer to 40 CFR part 112 for the full text of the rule.

The definition of mobile refueler describes vehicles of various sizes equipped with a bulk storage container such as a cargo tank or tank truck that is used to fuel or defuel aircraft, motor vehicles, locomotives, tanks, vessels or other oil storage containers, including full trailers and tank semi-trailers. The definition also includes nurse tanks, which are mobile vessels used at farms to store and transport fuel for transfers to or from farm equipment, such as tractors and combines, and to other bulk storage containers, such as containers used to provide fuel to wellhead/relift pumps at rice farms. A nurse tank is often mounted on a trailer for transport around the farm, and this function is consistent with that of a mobile refueler.

The exemption from sized secondary containment for mobile refuelers also applies to other non-transportation-related tank trucks.[96] Other non-transportation-related tank trucks may operate similarly to mobile refuelers, though not specifically transferring fuel. Instead, these tank trucks may carry other oils such as transformer oils, lubrication oils, crude oil, condensate, or non-petroleum oils such as AFVOs. Examples include a truck used to refill oil-filled equipment at an electrical substation and a pump truck at an oil production facility. These tank trucks may have the same difficulty in complying with the sized secondary containment requirements as mobile refuelers. Therefore, all non-transportation-related tank trucks are excluded from the sized secondary containment requirements for bulk storage containers, however the general secondary containment requirements at §112.7(c) apply (see 73 FR 74236, December 5, 2008).

Vehicles used to store oil, operating as on-site fueling vehicles within locations such as construction sites, military, or civilian remote operations support sites, or rail sidings are generally considered non-

[96] For more information on the jurisdiction of non-transportation-related tank trucks see *Chapter 2: SPCC Rule Applicability*.

transportation-related. Indicators of when a vehicle is intended to be used as a storage tank (and therefore considered non-transportation-related) include, but are not limited to:

- The vehicle is not licensed for on-road use;
- The vehicle is fueled on-site and never moves off-site; or
- The vehicle is parked on a home-base facility and is filled up off-site but then returns to the home base to fuel other equipment located exclusively within the home-base facility, and only leaves the site to obtain more fuel.

The exemption from sized secondary containment requirements does not apply to vehicles that are used primarily to store oil in a stationary location, such as tanker trucks used to supplement storage and serving as a fixed tank. An indicator that a vehicle is intended to store oil in a fixed location is that the vehicle is no longer mobile (e.g., it is hard-piped or permanently parked, or that the tank car has been separated from the cab of the truck).

Tip – Non-transportation related vehicles and railroad cars

The 1971 Memorandum of Understanding between EPA and the Department of Transportation (DOT) states that "highway vehicles and railroad cars which are used for the transport of oil exclusively within the confines of a non-transportation-related facility and which are not intended to transport oil in interstate or intrastate commerce" are considered non-transportation-related, and therefore fall under EPA's regulatory jurisdiction. For example, some oil refinery tank trucks and fueling trucks dedicated to a particular facility (such as a construction site, military base, or similar large facility) fall under this category.

4.7.7 Bulk Storage Containers at Oil Production Facilities (Sized Secondary Containment Requirements, §112.9(c)(2))

The secondary containment requirements of §112.9(c)(2) apply to all tank battery, separation, and treating facility installations at a regulated oil production facility, except for flow-through process vessels that comply with the alternative requirements under §112.9(c)(5), and produced water containers that comply with the alternative requirements of §112.9(c)(6).

According to the 2002 rule preamble, the sized secondary containment requirement at §112.9(c)(2) is not required for the entire leased area, merely for the contents of the largest single container in the tank battery, separation, and treating facility installation, with sufficient freeboard to contain precipitation." (67 FR 47128, July 17 2002) Thus, containers (e.g. drums storing

§112.9(c)(2)

Except as described in paragraph (c)(5) of this section for flow-through process vessels and paragraph (c)(6) of this section for produced water containers and any associated piping and appurtenances downstream from the container, construct all tank battery, separation, and treating facility installations, so that you provide a secondary means of containment for the entire capacity of the largest single container and sufficient freeboard to contain precipitation. You must safely confine drainage from undiked areas in a catchment basin or holding pond.

Note: The above text is an excerpt of the SPCC rule. Refer to 40 CFR part 112 for the full text of the rule.

lubrication oil, which are not located within the tank battery are subject only to the general secondary containment requirements of §112.7(c) and not subject to §112.9(c)(2).

Section 112.9(c)(2) specifies that secondary containment be designed so that it is able to contain the entire capacity of the largest single container with sufficient freeboard to contain precipitation.[97] Additionally, pursuant to §112.9(c)(2), if facility drainage is used as a method of secondary containment for bulk storage containers, drainage from undiked areas must be safely confined in a catchment basin or holding ponds. Although the undiked drainage requirements of §112.9(c)(2) do not apply to other areas of the facility or lease, such as truck transfer or wellhead or flowline areas because they are not bulk storage containers, the rule does require that field drainage systems (such as drainage ditches or road ditches), and oil traps, sumps, or skimmers be inspected at regularly scheduled intervals. Promptly remove any accumulations of oil in these drainage systems that may have resulted from a small discharges (§112.9(b)(2)).

Section 112.7(c) also applies and requires the entire containment system, including walls and floor, must be capable of containing oil and must be constructed so that any discharge from a primary containment system, such as a tank, will not escape the containment system before cleanup occurs.[98]

The facility owner/operator may determine that it is impracticable to provide sized secondary containment in accordance with §112.9(c)(2). Pursuant to §112.7(d), the SPCC Plan must then clearly explain why secondary containment is not practicable, and document how the alternative regulatory requirements of §112.7(d) are implemented. Owners or operators of unattended facilities need to determine how to identify when an oil discharge occurs in order to effectively implement an oil spill contingency plan. This may involve additional site inspections, or some other method as determined appropriate by a PE.

Tip – Oil pits

Because a pit used as a form of secondary containment may pose a threat to birds and wildlife if oil is present in the pit, EPA encourages owners or operators who use a pit to take measures to mitigate the effect of the pit on birds and wildlife. Such measures may include netting, fences, or other means to keep birds or animals away. In some cases, pits may also cause a discharge as described in §112.1(b). The discharge may occur when oil spills over the top of the pit or when oil seeps through the ground into the groundwater, and then to navigable waters or adjoining shorelines. Therefore, EPA recommends that an owner or operator not use pits in an area where such pit may prove a source of such discharges. Should the oil reach navigable waters or adjoining shorelines, it is a reportable discharge under 40 CFR 110.6.

(67 FR 47116; July 17, 2002)

4.7.8 Onshore Drilling or Workover Equipment (Secondary Containment Requirements, §112.10(c))

Section 112.10(c) applies to onshore oil drilling and workover facilities. Areas with drilling and workover equipment are required to provide catchment basins or diversion structures to intercept and contain discharges

[97] Refer to *Section 4.3.2* of this chapter for more information on calculating sufficient freeboard.

[98] Refer to *Section 4.4.2* of this chapter for more information on sufficiently impervious secondary containment.

of fuel, crude oil, or oily drilling fluids. This provision contains no specific sizing requirement, and no freeboard requirement; it is essentially similar to the general secondary containment requirement of §112.7(c).

§112.10(c)

Provide catchment basins or diversion structures to intercept and contain discharges of fuel, crude oil, or oily drilling fluids.

Note: The above text is an excerpt of the SPCC rule. See 40 CFR part 112 for the full text of the rule.

The facility owner/operator may determine that it is impracticable to provide secondary containment in accordance with §112.10(c). Pursuant to §112.7(d), the SPCC Plan must then clearly explain why secondary containment is not practicable, and document how the alternative regulatory requirements of §112.7(d) are implemented.

4.8 Alternative Measures in Lieu of Secondary Containment at Oil Production Facilities

4.8.1 Flow-through Process Vessels at Oil Production Facilities (General Secondary Containment Requirements, §112.7(c) and Alternative Requirements)

Flow-through process vessels at oil production facilities, such as horizontal or vertical separation vessels (e.g., heater-treater, free-water knockout, and gun barrel) have the primary purpose of separating oil from other fractions (water and/or gas) and sending the fluid streams to the appropriate container. These flow-through process vessels are bulk storage containers and are subject to the bulk storage container requirements of §112.9(c) including specific secondary containment requirements of §112.9(c)(2).

There is a potential fire-hazard if spilled oil collects around heater-treaters when dikes or berms are used to comply with the sized secondary containment requirements of the SPCC rule. Therefore, as an alternative to the sized secondary containment and inspection requirements for bulk storage containers at oil production facilities, §§112.9(c)(2)[99] and 112.9(c)(3), an oil production facility owner or operator may opt to provide general secondary containment in accordance with §112.7(c), and comply with the following requirements for flow-through process vessels at oil production facilities:

- Periodically and on a regular schedule, visually inspect and/or test flow-through process vessels and associated components (such as dump valves) for leaks, corrosion, or other conditions that could lead to a discharge as described in §112.1(b);
- Take corrective action or make repairs to flow-through process vessels and any associated components as indicated by regularly scheduled visual inspections, tests, or evidence of an oil discharge; and
- Promptly remove or initiate actions to stabilize and remediate any accumulations of oil discharges.

[99] See *Section 4.7.7*.

The additional requirements are necessary because oil production facilities are generally unattended, so there is a lower potential to immediately discover and correct a discharge than at other facilities that are typically attended during hours of operation. These alternative measures are optional, i.e., the owner or operator may still choose to comply with the sized secondary containment and inspection requirements of §§112.9(c)(2) and 112.9(c)(3). The facility owner or operator can decide which option is best suited to the design and operation of the facility. For more information on the alternate provisions for flow-through process vessels, see *Chapter 7: Inspection, Evaluation, and Testing*, *Section 7.2.9*.

SPCC Plans that include the alternative measures in §112.9(c)(5) must address how flow-through process vessels comply with general secondary containment requirements of §112.7(c). Flow-through process vessels must be provided with secondary containment so that any discharge does not escape the containment system before cleanup occurs. In determining how to provide appropriate general secondary containment for flow-through process vessels, an oil production facility owner or operator may consider the typical failure mode and most likely quantity of oil that would be discharged (see §112.7(c)). Based on site-specific conditions, the owner or operator can determine what capacity of secondary containment is needed, and design the containment method accordingly. The design for general secondary containment should address site-specific factors, including, but not limited to, frequency of site visits, rate of flow of the wells, capacity of the containers, and whether the facility is equipped with automatic shut-off devices to prevent an overflow (see 73 FR 74278, December 5, 2008).

The general secondary containment provision allows for the use of both active and passive containment measures to prevent a discharge to navigable waters or adjoining shorelines. However, active containment measures would generally have limited applicability at oil production facilities because these facilities are typically not attended and owners or operators may not be able to detect a discharge in a timely manner to successfully implement the active containment measures. In contrast, passive containment measures are installations that do not require deployment or action by the owner or operator and may be more appropriate for unattended oil production operations. *Section 4.4.1* provides several examples of the use of active and passive containment measures at an SPCC-regulated facility.

Owners or operators of oil production facilities that implement the alternative provisions for flow-through process vessels in accordance with §112.9(c)(5) are not required to locate flow-through process vessels within a secondary containment system sized for the entire capacity of the largest single container and sufficient freeboard to contain precipitation. However, oil production facility owners and operators may want to provide secondary containment (such as berms) around the entire tank battery, which is a typical design for many oil production facilities. These batteries can include flow-through process vessels, such as separators, along with oil stock tanks and other bulk storage containers. Such a facility design would provide the maximum environmental protection (see 73 FR 74277, December 5, 2008).

Further, the owner/operator of the facility must install sized secondary containment and comply with bulk storage container inspection requirements (§112.9(c)(2) and (c)(3)) for flow-through process vessels within six months of a discharge(s) from flow-through process equipment as described below and a report must be submitted to the RA in accordance with the requirements of §112.4:

- More than 1,000 U.S. gallons of oil in a single discharge to navigable waters or adjoining shorelines, or
- More than 42 U.S. gallons of oil in each of two discharges to navigable waters or adjoining shorelines within any twelve month period.

This excludes discharges that are the result of natural disasters, acts of war, or terrorism. When determining the applicability of this SPCC reporting requirement, the gallon amount(s) specified (either 1,000 or 42) refers to the amount of oil that actually reaches navigable waters or adjoining shorelines not the total amount of oil spilled. EPA considers the entire volume of the discharge to be oil for the purposes of these reporting requirements.

EPA inspectors should review inspection records to ensure that the Plan is being properly implemented to comply with the alternative requirements. If, upon inspection, it is discovered that the owner or operator of the facility is not implementing the alternative requirements included in the SPCC Plan, then the RA may require the Plan be amended to include sized secondary containment for flow-through process vessels at the facility and inspections in accordance with 112.9(c)(2) and (c)(3).

Finally, if the owner or operator of the facility determines that secondary containment is impracticable and chooses not to implement the alternative requirements in §112.9(c)(5), then the facility owner or operator may comply with §112.7(d). The SPCC Plan must then clearly explain why secondary containment is impracticable; include with the SPCC Plan an oil contingency plan following the provisions of 40 CFR part 109 (unless he or she has submitted an FRP under §112.20); and provide a written commitment of manpower, equipment, and materials required to expeditiously control and remove any quantity of oil that may be harmful (§112.7(d)). Owners or operators of unattended facilities may need to determine how to quickly identify when an oil discharge occurs in order to effectively implement an oil spill contingency plan. This may involve additional site inspections, or some other method as determined appropriate by a PE.

4.8.2 Produced Water Containers at Oil Production Facilities (General Secondary Containment Requirements, §112.7(c) and Alternative Requirements)

Produced water containers are defined in §112.2 and are typically located within a tank battery at an oil production facility where they are used to store well fluids remaining after marketable crude oil is separated from the fluids extracted from the reservoir and prior to disposal, re-injection, subsequent use (or beneficial reuse), or further treatment. Under normal operating conditions, a layer of oil may be present on top of the fluids in these produced water containers. These produced water containers are typically at the end of the oil treatment process and often accumulate emulsified oil not captured in the separation process. The amount of oil by volume observed in produced water containers varies, but is generally estimated to range from less than one to up to ten percent, and can be greater.

§112.2

Produced water container means a storage container at an oil production facility used to store the produced water after initial oil/water separation, and prior to reinjection, beneficial reuse, discharge, or transfer for disposal.

Note: The above text is an excerpt of the SPCC rule. Refer to 40 CFR part 112 for the full text of the rule.

Skimming operations for produced water containers that remove or recover free phase oil on a regular basis may operate similarly to separation operations for flow-through process vessels. Therefore, the additional compliance measures for produced water containers described below is consistent with alternative compliance options provided for other bulk storage containers (i.e., flow-through process vessels) which separate oil and water mixtures.

For produced water containers, instead of complying with the sized secondary containment and inspection requirements for bulk storage containers at oil production facilities, §§112.9(c)(2)[100] and 112.9(c)(3), an oil production facility owner or operator may opt to provide general secondary containment and comply with the following additional requirements:

- Implement on a regular schedule a procedure to separate free-phase oil (or skimming program).
- Regularly scheduled visual inspection and/or testing of produced water containers and associated piping and appurtenances for leaks, corrosion, or other conditions that could lead to a discharge as described in §112.1(b).
- Corrective action or repairs to produced water containers and any associated piping as indicated by regularly scheduled visual inspections, tests, or evidence of an oil discharge.
- Prompt removal or initiation of actions to stabilize and remediate any accumulations of oil discharges associated with produced water containers.

The general secondary containment requirement at §112.7(c) calls for secondary containment to be designed to hold the most likely quantity of oil potentially discharged in an event, rather than installation of sized secondary containment designed to hold the contents of the largest container with sufficient freeboard. Typically, the quantity of oil contained by general secondary containment is expected to be smaller than the amount of oil that would need to be contained by sized secondary containment. Good general secondary containment practices can be successfully implemented if such practices are designed by a PE in consideration of the site specific factors and in combination with additional oil spill prevention practices including inspections, procedures to minimize the amount of free-phase oil in the container and procedures to remove/ remediate discharged oil.

[100] See *Section 4.7.7*.

§112.9(c)(6)

Produced water containers. For each produced water container, comply with §112.9(c)(1) and (c)(4); and §112.9(c)(2) and (c)(3), or comply with the provisions of the following paragraphs (c)(6)(i) through (v):

(i) Implement, on a regular schedule, a procedure for each produced water container that is designed to separate the free-phase oil that accumulates on the surface of the produced water. Include in the Plan a description of the procedures, frequency, amount of free-phase oil expected to be maintained inside the container, and a Professional Engineer certification in accordance with §112.3(d)(1)(vi). Maintain records of such events in accordance with §112.7(e). Records kept under usual and customary business practices will suffice for purposes of this paragraph. If this procedure is not implemented as described in the Plan or no records are maintained, then you must comply with §112.9(c)(2) and (c)(3).

(ii) On a regular schedule, visually inspect and/or test the produced water container and associated piping for leaks, corrosion, or other conditions that could lead to a discharge as described in §112.1(b) in accordance with good engineering practice.

(iii) Take corrective action or make repairs to the produced water container and any associated piping as indicated by regularly scheduled visual inspections, tests, or evidence of an oil discharge.

(iv) Promptly remove or initiate actions to stabilize and remediate any accumulations of oil discharges associated with the produced water container.

(v) If your facility discharges more than 1,000 U.S. gallons of oil in a single discharge as described in §112.1(b), or discharges more than 42 U.S. gallons of oil in each of two discharges as described in §112.1(b) within any twelve month period from a produced water container subject to this subpart (excluding discharges that are the result of natural disasters, acts of war, or terrorism) then you must, within six months from the time the facility becomes subject to this paragraph, ensure that all produced water containers subject to this subpart comply with §112.9(c)(2) and (c)(3).

Note: The above text is an excerpt of the SPCC rule. Refer to 40 CFR part 112 for the full text of the rule.

Produced water containers must be provided with secondary containment so that any discharge does not escape the containment system before cleanup occurs. In determining how to provide appropriate general secondary containment for produced water containers, a production facility owner or operator may consider the typical failure mode and most likely quantity of oil that would be discharged (*see* §112.7(c)). Based on site-specific conditions, the owner or operator can determine what capacity of secondary containment is needed, and design the containment method accordingly. The design for general secondary containment should address site-specific factors, including, but not limited to, frequency of site visits, rate of flow of the wells, frequency of the free-phase oil separation and removal process or procedure, the amount of oil that typically accumulates on the surface of the produced water container between skimming operations, capacity of the containers, and whether the facility is equipped with automatic shut-off devices to prevent an overflow.

The general secondary containment provision allows for the use of both active and passive containment measures to prevent a discharge to navigable waters or adjoining shorelines. However, active containment measures would generally have limited applicability at oil production facilities because these facilities are typically not attended and owners or operators may not be able to detect a discharge in a timely manner to successfully implement the active measures. In contrast, passive containment measures are installations that do

not require deployment or action by the owner or operator and may be more appropriate for unattended oil production operations. See *Section 4.4.1* of this guidance for several examples of the use of active and passive containment measures at an SPCC-regulated facility.

The facility owner or operator must implement a process and/or procedure for the produced water container (s) that is designed to remove the free-phase oil that accumulates on the surface of the produced water container. This process or procedure must be implemented on a regular schedule so that the amount of free phase oil that collects in produced water containers is within the amounts managed by the general secondary containment system designed by the PE to address the typical failure mode, and the most likely quantity of oil that would be discharged.

The SPCC Plan must include a description of the free-phase oil separation and removal process or procedure, the frequency it is implemented or operated, the amount of free-phase oil expected to be maintained inside the container, and a description of the adequacy of the general secondary containment approach for the produced water container, including the anticipated typical failure mode and the method, design, and capacity for general secondary containment. Additionally, the owner or operator must keep records of the implementation of these procedures in accordance with §112.7(e) (see 73 FR 74287, December 5, 2008).

Section 112.3(d)(1)(vi) requires the PE to certify that an oil removal process or procedure for produced water containers is designed according to good engineering practice to reduce the accumulation of free-phase oil, and that the process or procedure and frequency for required inspections, maintenance, and testing have been established. Oil production facility owners or operators that meet the criteria for Tier II qualified facilities (as described in §112.3(g)) and choose to self-certify their SPCC Plans cannot take advantage of the flexibility allowed in the alternative requirements for produced water containers, unless the procedures for skimming produced water containers are reviewed and certified in writing by a PE (§112.6(b)(3)(iii) and 112.6(b)(4)).

If the facility experiences a discharge of more than 1,000 U.S. gallons of oil in a single discharge to navigable waters or adjoining shorelines, or discharges more than 42 U.S. gallons of oil in each of two discharges to navigable waters or adjoining shorelines, occurring within any twelve month period (excluding discharges that are the result of natural disasters, acts of war, or terrorism)[101] from any produced water container, then the facility owner/operator may no longer take advantage of this alternative option and must comply with the sized secondary containment requirements at §112.9(c)(2) and the inspection requirements at §112.9(c)(3) within six months for all produced water containers at the facility. Additionally, in accordance with the requirements of §112.4, the owner or operator must submit a report to the RA within 60 days of the discharge(s) and to the appropriate state agency or agencies in charge of oil pollution control activities.

The facility owner/operator may determine that it is impracticable to provide sized secondary containment for produced water containers in accordance with §112.9(c)(2) and choose not to implement the alternative requirements for these containers as described in §112.9(c)(6). The SPCC Plan must then clearly

[101] When determining the applicability of this SPCC reporting requirement, the gallon amount(s) specified (either 1,000 or 42) refers to the amount of oil that actually reaches navigable waters or adjoining shorelines not the total amount of oil spilled. EPA considers the entire volume of the discharge to be oil for the purposes of these reporting requirements.

explain why secondary containment is not practicable; include with the SPCC Plan an oil spill contingency plan following the provisions of 40 CFR part 109 (unless he or she has submitted an FRP under §112.20); and provide a written commitment of manpower, equipment, and materials required to expeditiously control and remove any quantity of oil that may be harmful (§112.7(d)). Owners or operators of unattended facilities may need to determine how to quickly identify when an oil discharge occurs in order to effectively implement an oil spill contingency plan. This may involve additional site inspections, or some other method as determined appropriate by a PE.

Finally, these alternative measures are optional. The owner or operator may still choose to comply with the sized secondary containment and inspection requirements of §§112.9(c)(2) and 112.9(c)(3) for produced water containers. The facility owner or operator can decide which option is best suited to the design and operation of the facility. For more information on the alternate provisions for produced water containers, see *Chapter 7: Inspection, Evaluation, and Testing*, *Section 7.2.10.*

Tip – Discharge from flow-through process vessels or produced water containers

If flow-through process vessels or produced water containers at the facility cause a single discharge of oil to navigable waters or adjoining shorelines exceeding 1,000 U.S. gallons, or two discharges of oil to navigable waters or adjoining shorelines each exceeding 42 U.S. gallons within any 12-month period then:

- Install sized secondary containment with sufficient freeboard for precipitation for the type of containers that caused the discharge (i.e., either all flow-process vessels or all produced water containers at the facility) within six months of such a discharge(s), and
- Submit a report to the Regional Administrator (in accordance with the requirements of §112.4) within 60 days of the discharge(s) and to the appropriate state agency or agencies in charge of oil pollution control activities.

The report must include the name of the facility; the name of the owner or operator; location of the facility; maximum storage or handling capacity of the facility and normal daily throughput; corrective action and countermeasures taken, including a description of equipment repairs and replacements; an adequate description of the facility, including maps, flow diagrams, and topographical maps, as necessary; the cause of the discharge(s), including a failure analysis of the system or subsystem in which the failure occurred; additional preventive measures taken or contemplated to minimize the possibility of recurrence; and any other information as the Regional Administrator may reasonably require pertinent to the Plan or discharge.

Figure 4-13: List of SPCC requirements eligible for impracticability determinations.

Rule Element	Relevant Section(s)	Evaluation	Verification	Nonconformance
ALL FACILITIES				
General Containment	112.7(c)	Are appropriate containment and/or diversionary structures provided to prevent a discharge to navigable waters of adjoining shorelines? Is the containment system capable of containing oil and constructed so that any discharge from the primary containment system will not escape before cleanup occurs? Are active measures properly documented? Is the most likely discharge volume documented?	Visual.	Does the Plan explain why secondary containment is impracticable? Is a Contingency Plan (or FRP) provided? Does the Plan include a written commitment of manpower, equipment, and materials? Does the facility conduct periodic integrity testing of bulk storage containers and integrity and leak testing of associated valves and piping? Does the facility implement alternative measures for qualified oil-filled operational equipment (§112.7(k))? Does an oil production facility implement alternative measures for flowlines and intra-facility gathering lines as provided in §112.9(d)(3)?
Loading/unloading Racks	112.7(h)(1)	Does the loading/unloading rack area drainage flow into a catchment basin or treatment facility? If not, is a quick drainage system used? Is the secondary containment system sized to contain the maximum capacity of any single compartment of a tank car or tank truck loaded there?	Visual.	Does the Plan explain why secondary containment is impracticable? Is a Contingency Plan (or FRP) provided? Does the Plan include a written commitment of manpower, equipment, and materials?
ALL ONSHORE FACILITIES, EXCEPT OIL PRODUCTION				
Bulk Storage Containers	112.8(c)(2) OR 112.12(c)(2)	Is the secondary containment system (except when for mobile refuelers and other non-transportation-related tank trucks) sized to contain the entire capacity of the largest single container and sufficient freeboard to contain precipitation? Are dikes sufficiently impervious to contain oil?	Visual.	Does the Plan explain why secondary containment is impracticable? Is a Contingency Plan (or FRP) provided? Does the Plan include a written commitment of manpower, equipment, and materials? Does the facility conduct periodic integrity testing of bulk storage containers and integrity and leak testing of associated valves and piping?

Rule Element	Relevant Section(s)	Evaluation	Verification	Nonconformance
	112.8(c)(11) OR 112.12(c)(11)	Are mobile or portable oil containers (except mobile refuelers and other non-transportation-related tank trucks) located within a dike, catchment basin or other means of secondary containment large enough to contain the largest single container and sufficient freeboard to contain precipitation?	Visual.	Does the Plan explain why secondary containment is impracticable? Is a Contingency Plan (or FRP) provided? Does the Plan include a written commitment of manpower, equipment, and materials? Does the facility conduct periodic integrity testing of bulk storage containers and integrity and leak testing of associated valves and piping?
ONSHORE OIL PRODUCTION FACILITIES				
Drainage	112.9(c)(2)	Is drainage from undiked areas safely confined in a catchment basin or holding pond?	Visual.	Does the Plan explain why secondary containment is impracticable? Is a Contingency Plan (or FRP) provided? Does the Plan include a written commitment of manpower, equipment, and materials? Does the facility conduct periodic integrity testing of bulk storage containers and integrity and leak testing of associated valves and piping?
Bulk Storage Containers	112.9(c)(2)	Are all tank battery, separation, and treatment facility installations provided with secondary containment that can contain the largest single container and sufficient freeboard to contain precipitation?	Visual.	Does the Plan explain why secondary containment is impracticable? Is a Contingency Plan (or FRP) provided? Does the Plan include a written commitment of manpower, equipment, and materials? Does the facility conduct periodic integrity testing of bulk storage containers and integrity and leak testing of associated valves and piping? Does the facility implement alternative measures for flow-through process vessels in accordance with §112.9(c)(5)? Does the facility implement alternative measures for produced water tanks in accordance with §112.9(c)(6)?

Rule Element	Relevant Section(s)	Evaluation	Verification	Nonconformance
Flow-through Process Vessels	112.9(c)(2)	Are all flow-through process vessels provided with secondary containment that can contain the largest single container and sufficient freeboard to contain precipitation? - or - Are appropriate containment and/or diversionary structures provided? Is the containment system capable of containing oil and constructed so that any discharge from the primary containment system will not escape before cleanup occurs? Are flow-through process vessels and components inspected or tested for leaks, corrosion or other conditions that could lead to a discharge to navigable waters or adjoining shorelines? Are oil accumulations promptly removed or actions initiated to stabilize and remediate them? Was corrective action taken if a discharge occurred?	Visual.	Does the facility comply with §112.9(c)(2)? - or - Does the Plan explain why secondary containment is impracticable? Is a Contingency Plan (or FRP) provided? Does the Plan include a written commitment of manpower, equipment, and materials? Does the facility conduct periodic integrity testing of bulk storage containers and integrity and leak testing of associated valves and piping? - or - Does the facility comply with alternative requirements in §112.9(c)(5)?

Rule Element	Relevant Section(s)	Evaluation	Verification	Nonconformance
Produced Water Containers	112.9(c)(2)	Are all produced water containers provided with secondary containment that can contain the largest single container and sufficient freeboard to contain precipitation? - or - Are appropriate containment and/or diversionary structures provided? Is the containment system capable of containing oil and constructed so that any discharge from the primary containment system will not escape before cleanup occurs? Is there a procedure to separate free-phase oil? Are records maintained that document implementation of the procedure? Is periodic inspection and/or testing of produced water containers and any associated piping and appurtenances for leaks, corrosion, or other conditions that could lead to a discharge to navigable waters or adjoining shorelines, conducted? Are corrective action or repairs to produced water containers and any associated piping taken, as indicated by regularly scheduled visual inspections, tests, or evidence of an oil discharge? Are oil accumulations promptly removed or actions initiated to stabilize and remediate them?	Visual.	Does the facility comply with §112.9(c)(2)? - or - Does the Plan explain why secondary containment is impracticable? Is a Contingency Plan (or FRP) provided? Does the Plan include a written commitment of manpower, equipment, and materials? Does the facility conduct periodic integrity testing of bulk storage containers and integrity and leak testing of associated valves and piping? - or - Does the facility comply with alternative requirements in §112.9(c)(6)?
ONSHORE OIL DRILLING AND WORKOVER FACILITIES				
Drainage	112.10(c)	Are catchment basins or diversion structures provided to intercept and contain discharges of fuel, crude oil, or oily drilling fluids?	Visual.	Does the Plan explain why secondary containment is impracticable? Is a Contingency Plan (or FRP) provided? Does the Plan include a written commitment of manpower, equipment, and materials? Does the facility conduct periodic integrity testing of bulk storage containers and integrity and leak testing of associated valves and piping?

Chapter 5 Oil/Water Separators

5.1 Introduction

The intended use of an oil/water separator(s) (OWS) determines whether the separator is subject to the SPCC regulations and, if so, what provisions are applicable. This chapter explains the applicability of the SPCC rule to OWS, and clarifies the exemption for certain uses, including equipment, vessels, and containers that are not specifically called "OWS" but perform oil/water separation, such as water clarifiers at wastewater treatment plants. This chapter also discusses the alternative compliance options for flow-through process vessels at oil production facilities.

Table 5-1 below outlines the SPCC rule applicability for various uses of OWS. Only OWS used exclusively to treat wastewater and not used to satisfy any requirement of 40 CFR part 112 are exempt from all SPCC requirements. OWS used in oil production, recovery or recycling and to meet the secondary containment requirements of the rule are not exempt.

Table 5-1: SPCC rule applicability for various uses of OWS.

Wastewater Treatment	Secondary Containment	Oil Production	Oil Recovery and/or Recycling
Separators are exempt from all SPCC requirements in accordance with §112.1(d)(6) and do not count toward facility storage capacity.	Separators that are used as part of a secondary containment system and are not intended for oil storage or use do not themselves require secondary containment and do not count toward facility storage capacity. However, they are subject to the design specifications (e.g., capacity) for the secondary containment requirements with which they are designed to comply.	Separators are bulk storage containers and are not exempt; they count toward the facility storage capacity. They are subject to the provisions of §§112.7 and §§112.9(c) or 112.11(b) and (d).	Separators are not exempt and count toward the facility storage capacity. Separators are oil-filled manufacturing equipment subject to the provisions of §112.7 and §§112.8(b) and (d) or 112.12(b) and (d), as applicable.[102]

[102] The §§112.8(c) and 112.12(c) provisions for bulk storage containers do not apply because oil/water separators at these facilities function as oil-filled manufacturing equipment and are not bulk storage containers.

The remainder of this chapter is organized as follows:

- ***Section 5.2*** summarizes applicable SPCC rule provisions to the four uses of OWS identified above.
- ***Section 5.3*** discusses the exemption for the use of an OWS as wastewater treatment.
- ***Section 5.4*** addresses applicable SPCC requirements for the use of an OWS as secondary containment.
- ***Section 5.5*** discusses applicable SPCC requirements for the use of an OWS at oil production facilities.
- ***Section 5.6*** discusses applicable SPCC requirements for the use of an OWS at oil recovery or recycling facilities.
- ***Section 5.7*** describes required documentation for OWS and the role of the EPA inspector in reviewing facilities with OWS.

5.2 Overview of Provisions Applicable to OWS

The following paragraphs briefly summarize the four uses of OWS and identify the SPCC provisions applicable to each. These requirements are discussed in greater detail in *Sections 5.3* through *5.6*.

5.2.1 Wastewater Treatment Facilities

Section 112.1(d)(6) of the SPCC rule addresses OWS used for wastewater treatment. Facilities or equipment used exclusively for wastewater treatment, and which do not satisfy any requirements of the SPCC rule, are exempt from the SPCC rule requirements. These OWS do not count toward facility storage capacity. Whether a wastewater treatment facility or part thereof is used exclusively for wastewater treatment or used to satisfy an SPCC requirement will often be a facility-specific determination based upon the activities carried out at the facility and upon its configuration.

5.2.2 OWS Used for Secondary Containment

OWS used to meet the SPCC requirements for general secondary containment, sized secondary containment, or facility drainage are subject to applicable rule requirements, but they do not count toward storage capacity. These include OWS that are used to meet the secondary containment requirements of §§112.7(c), 112.7(h)(1), 112.8(c)(2), 112.8(c)(11), 112.12(c)(2), and/or 112.12(c)(11). Drainage systems that satisfy the secondary containment requirements may use OWS to recover oil and return it to the facility (see *Chapter 4: Secondary Containment and Impracticability* for a description of secondary containment requirements). Additionally, the drainage provisions in §§112.8(b) and 112.9(b) set forth design specifications for secondary containment at a facility.

5.2.3 Oil Production Facilities

Production, recovery, and recycling of oil are not considered wastewater treatment and, thus, are not eligible for the wastewater treatment exemption. For purposes of §112.1(d)(6), such activities also include recovery and recycling of crude oil at facilities associated with, and/or downstream of, production facilities, such as saltwater disposal (produced water) and injection facilities.

OWS associated with oil production activities are subject to §112.7 and applicable provisions of §112.9 for onshore oil production facilities or §112.11 for offshore oil production facilities. Examples of OWS associated with oil production, separation, and treatment include free water knockouts, two- and three-phase separators, and gun barrels.

5.2.4 Oil Recovery and/or Recycling Facilities

Oil recycling and recovery activities that collect and consolidate production fluids from multiple oil production facilities in an effort to further recover and treat oil prior to the disposal of production fluids are not eligible for the wastewater treatment exemption because the operations focus on oil treatment rather than wastewater treatment. These operations typically specialize in the treatment of production fluids and other oil recovery activities, and may include disposal and injection of production fluids. Other oil recycling operations include waste oil recyclers not associated with oil production operations (e.g., motor oil recyclers) and facilities engaged in the recovery and/or recycling of animal fats and vegetable oils (AFVO).

Figure 5-1 to *Figure 5-4* illustrate rule requirements or exemptions based upon the use of OWS at SPCC-regulated facilities.

Figure 5-1: OWS subject to wastewater treatment exemption.

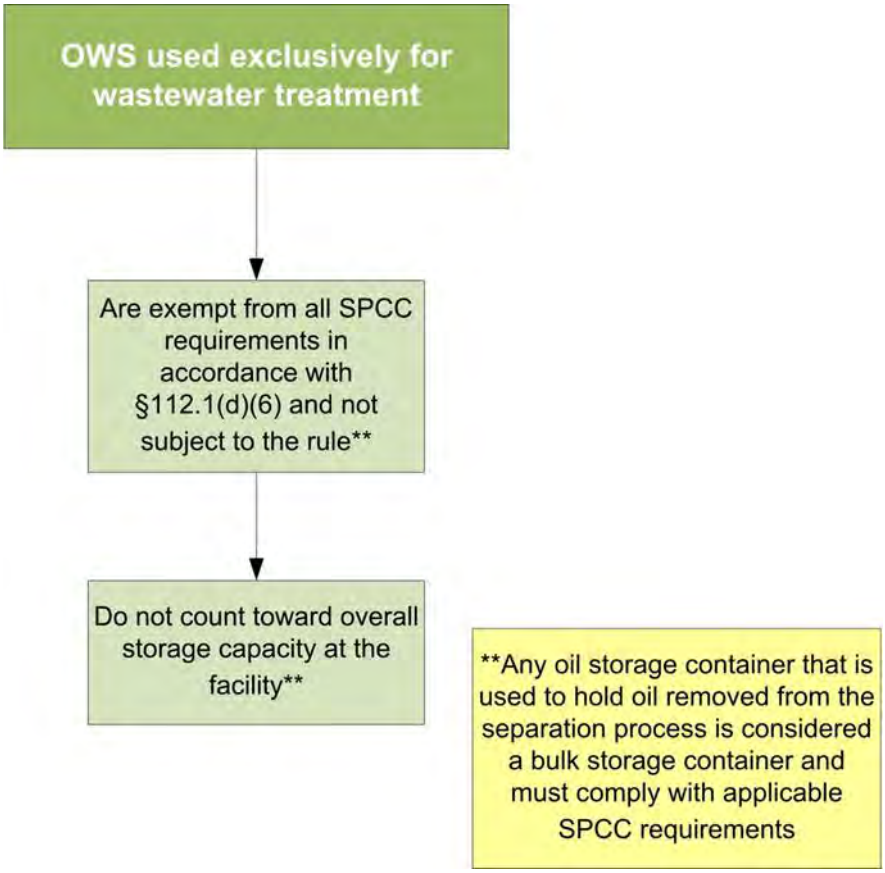


Figure 5-2: OWS used to satisfy SPCC rule requirements.

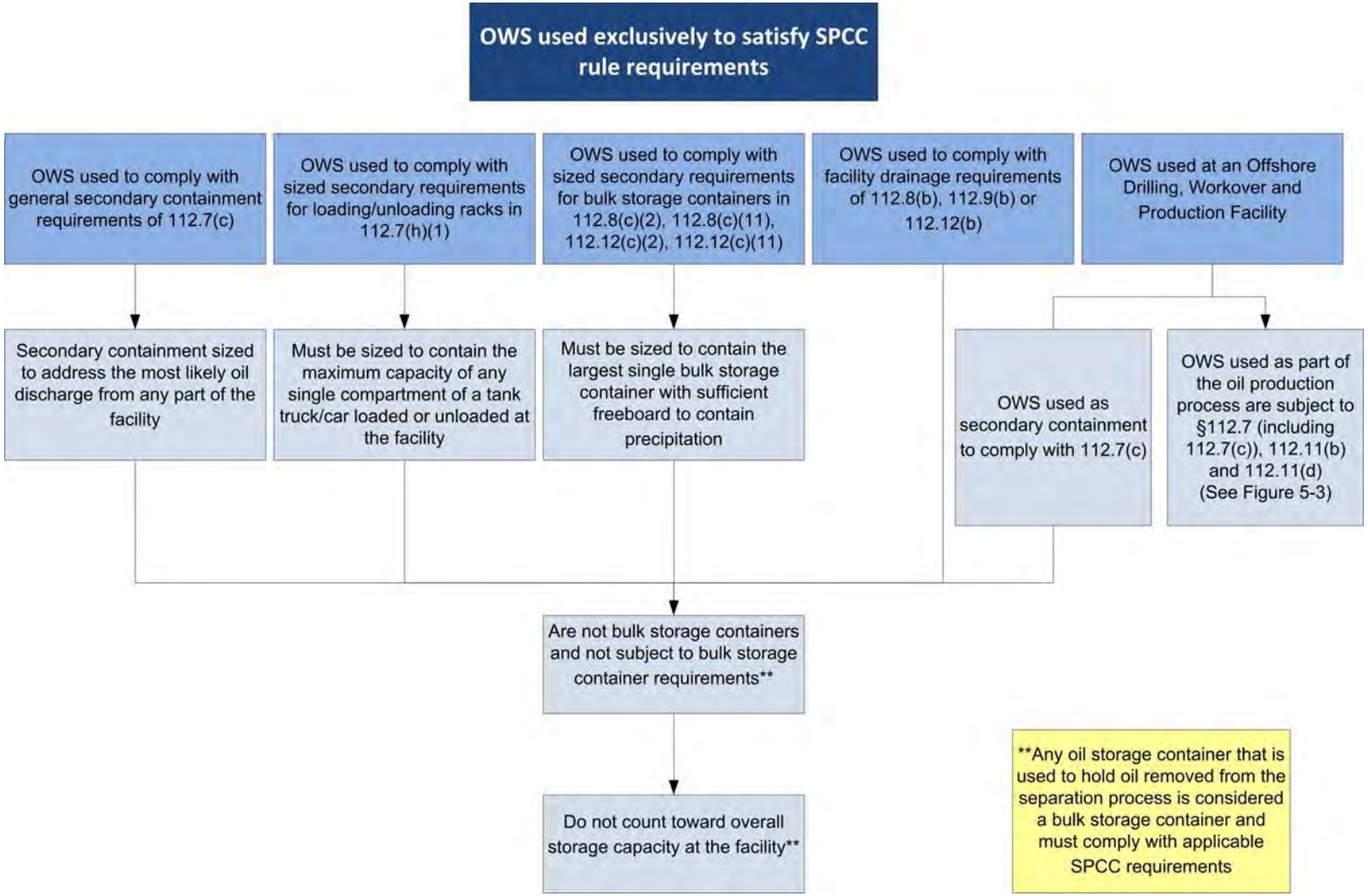


Figure 5-3: OWS at oil production facilities.

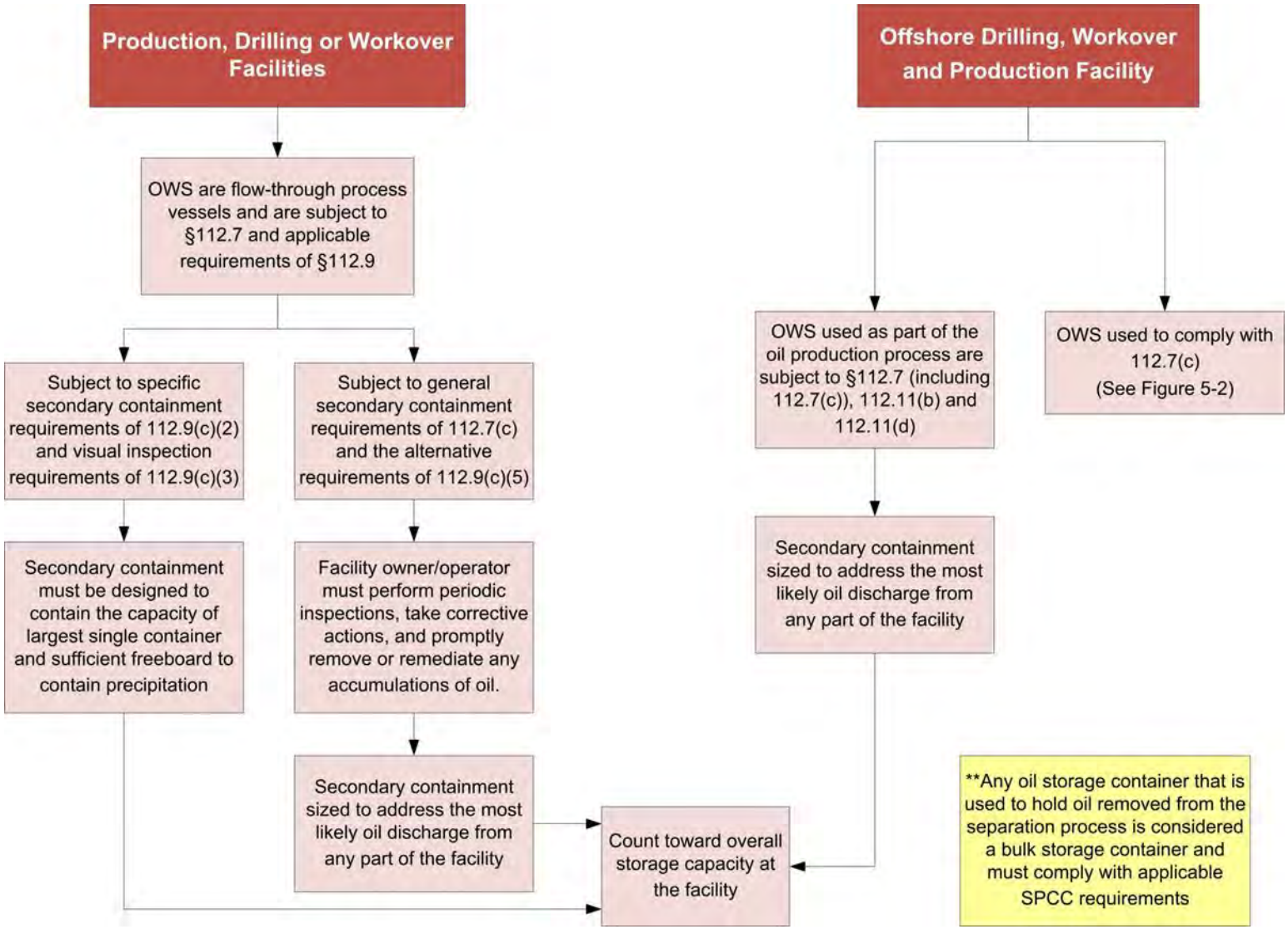
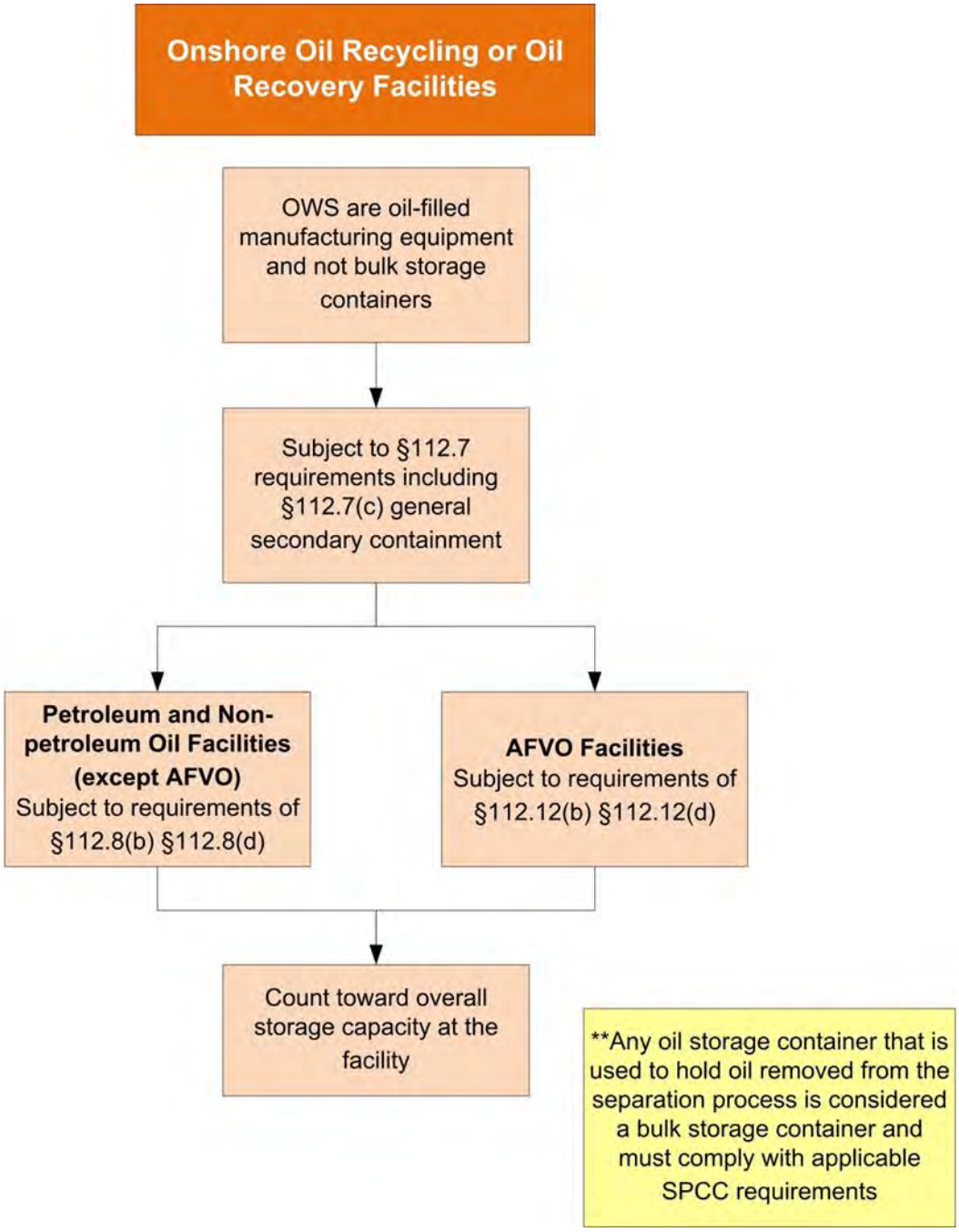


Figure 5-4: OWS at oil recovery and/or recycling facilities.

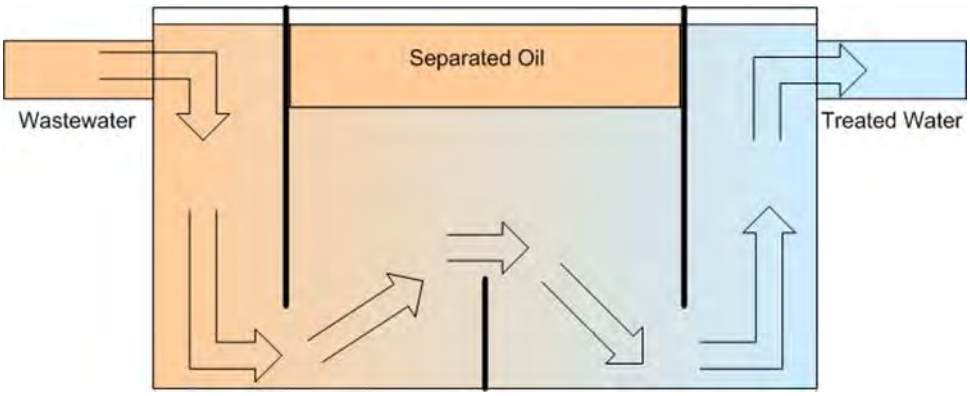


5.3 OWS Used for Wastewater Treatment

5.3.1 OWS Used for Wastewater Treatment

OWS used to pre-treat wastewater are typically standard gravity or enhanced gravity separators.[103] Standard gravity separators, as illustrated in *Figure 5-5* (separator designs may vary), are liquid containment structures that provide sufficient hydraulic retention time to allow oil droplets to rise to the surface. The oil forms a separate layer that can then be removed by skimmers, pumps, or other methods. The wastewater outlet is located below the oil level so that water leaving the separator is free of the oil that accumulates at the top of the unit. The inlet is often fitted with diffusion baffles to reduce turbulent flow that might prevent effective separation of the oil and might re-suspend settled pollutants.

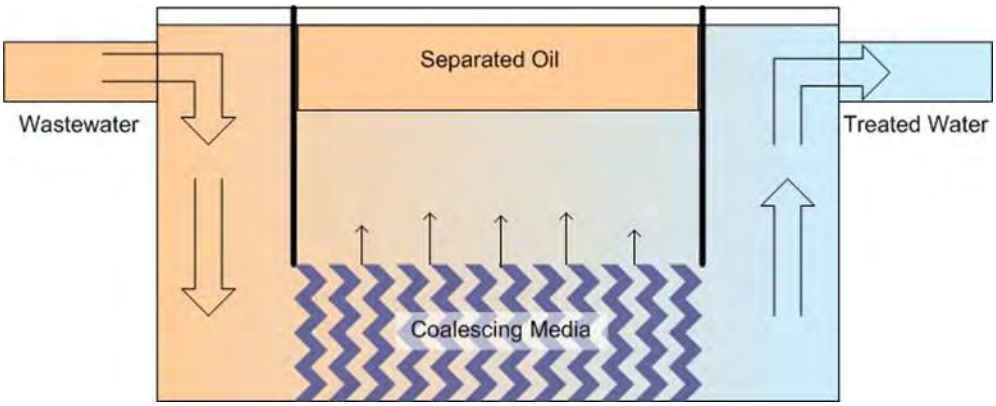
Figure 5-5: Standard gravity oil/water separator.



Enhanced gravity separators allow the separation of smaller oil droplets within confined spaces. These separators use a variety of coalescing media and small diameter cartridges that enhance laminar flow and separation of smaller oil droplets that accumulate on the separator surface for removal. *Figure 5-6* shows coalescing plates in the middle compartment (separator designs may vary).

[103] Other types of separators include vortex separators, which combine gravity with centrifugal forces.

Figure 5-6: Enhanced gravity oil/water separator.



OWS are flow-through equipment in which wastewater enters the separator and treated water exits the separator typically on a continual basis. To be effective, the OWS is sized appropriately in order for the unit to separate and contain the intended oil capacity, in addition to the flow-through wastewater quantity. Also, the design flow rate of the OWS is carefully considered when specifying a wastewater treatment system, as a flow rate above the maximum rate of the separator will cause the discharge of accumulated oil and/or untreated wastewater. The specifications from OWS manufacturers typically outline these and other design factors and considerations, along with operation and maintenance requirements, to ensure that the OWS is correctly constructed and operated for its intended use.

5.3.2 Applicability of the SPCC Rule to OWS Used for Wastewater Treatment

Section 112.1(d)(6) exempts "any facility or part thereof" that is used *exclusively* for wastewater treatment *and* is not used to meet any other requirement of the rule (excluding oil production, recovery, and recycling facilities). There are components of wastewater treatment facilities, such as treatment systems at publicly owned treatment works (POTWs) and industrial wastewater treatment facilities treating oily wastewater, that likely meet the two criteria for this exemption. OWS used exclusively for wastewater treatment are flow-through separators and are not engaged in a static process in an isolated container. For example, the presence of a water sump in a bulk storage container does not constitute wastewater treatment.

POTWs and other wastewater treatment facilities may have bulk storage containers and oil-filled equipment, as well as exempt OWS. The capacities of the bulk storage containers and oil-filled equipment are counted to determine whether the facility is subject to the requirements of the SPCC rule. The presence of an OWS at an otherwise regulated facility does not exempt the entire facility from the SPCC rule requirements. Such OWS capacity does not count toward the overall storage capacity of the facility, and only that equipment used for oil/water separation is not subject to any rule provisions. At wastewater treatment facilities, storage capacities to be counted include bulk storage containers, hydraulic equipment associated with the treatment process, containers used to store oil that feed an emergency generator associated with wastewater treatment, and slop tanks or other containers used to store oil resulting from treatment. All separate containers used to

store oil recovered by the separation process and all other equipment or containers at a regulated facility that do not qualify for the wastewater treatment exemption are required to meet the applicable SPCC requirements (67 FR 47069, July 17, 2002).

Examples of wastewater treatment OWS that may be eligible for the exemption of §112.1(d)(6) include:

- OWS at a wastewater treatment facility;
- OWS at an active groundwater remediation site;
- Grease traps that intercept and congeal oil and grease from liquid waste; and
- OWS in landfill leachate collection systems.

A separate container storing oil removed from an exempt separator is considered a bulk storage container and is subject to the SPCC rule requirements. Furthermore, OWS exempted from the SPCC rule may be subject to other federal, state, and local regulations. For example, many exempted wastewater treatment OWS are within wastewater treatment facilities or parts thereof subject to the National Pollutant Discharge Elimination System (NPDES) requirements under section 402 of the Clean Water Act (CWA). NPDES (or an approved state permit program) ensures review and approval of the facility's wastewater treatment plans and specifications, as well as operation/maintenance manuals and procedures, and requires a Storm Water Pollution Prevention Plan, which may include a Best Management Practice (BMP) Plan.[104]

Additionally, some facilities may be subject to pretreatment standards promulgated under §307(b) of the CWA. Pretreatment standards apply to "indirect discharges" that go first to a POTW via a collection system before being discharged to navigable waters. The General Pretreatment Regulations for Existing or New Sources of Pollution, found at 40 CFR part 403, prohibits an indirect discharger from introducing into a POTW a pollutant that passes through or interferes with treatment processes at the POTW, and also sets the framework for the implementation of categorical pretreatment standards. Specifically, 40 CFR 403.5(b)(6) prohibits the introduction into a POTW of "petroleum, oil, non-biodegradable cutting oil, or products of mineral oil origin in amounts that will cause interference or pass through."

[104] BMPs are operational conditions that may supplement or constitute effluent limitations in NPDES permits. Under §402(a)(2) of CWA, BMPs may be imposed in addition to effluent limits when the EPA Administrator determines that such conditions are necessary to carry out the provisions of the Act. See discussion of authority for NPDES and BMP provisions in the preamble to the 2002 final SPCC rule, 67 FR 47068.

Example of SPCC Rule Applicability and Secondary Containment Requirements: Kitchen Grease Trap

A kitchen grease trap at a facility otherwise subject to the SPCC rule and that is used solely for the pretreatment of wastewater is eligible for the wastewater treatment exemption. However, the transfer of oily wastewater and sludge from this exempt grease trap, using a vacuum truck, is subject to the general containment requirements of §112.7(c) if the transfer area does not meet the definition of a "loading/unloading rack." Sufficient secondary containment for a grease trap unloading area may be provided by active containment measures deployed either prior to transfer (e.g., placement of a drain cover over a storm water drop inlet) or in reaction to a discharge as long as the certifying PE determines that the active containment measures are sufficient and can be reliably deployed in time to prevent the spilled material from reaching navigable waters or adjoining shorelines.

5.3.3 Wastewater Treatment Exemption Clarification for Dry Gas Production Facilities

A dry gas production facility is a facility that produces natural gas from a well (or wells) from which it does not also produce condensate or crude oil that can be drawn off the tanks, containers or other production equipment at the facility. Since no oil is being "produced" at these dry gas facilities they may be eligible for the wastewater treatment exemption because they are not "oil production, oil recovery, or oil recycling facilities." Produced water containers used exclusively for wastewater treatment at dry gas production facilities are not excluded from the wastewater treatment exemption (69 FR 29728, May 25, 2004). These produced water containers are eligible for the wastewater treatment exemption and therefore do not count toward oil storage capacity and are not subject to the rule's requirements.

It should be noted that in the 2008 amendments to the SPCC rule (73 FR 74236, December 5, 2008), EPA added the term "condensate" to the definition of production facility. The purpose of this amendment was to clarify that certain gas facilities (i.e., wet gas facilities) that produce oil in the form of condensate are oil production facilities and may be subject to the SPCC rule. As oil production facilities, wet gas facilities are not eligible for the waste water treatment exemption.

At 69 FR 29730, EPA stated that

"...[in] verifying that a particular gas facility is not an 'oil production, oil recovery, or oil recycling facility,' the Agency plans to consider, as appropriate, evidence at the facility pertaining to the presence or absence of condensate or crude oil that can be drawn off the tanks, containers or other production equipment at the facility, as well as pertinent facility test data and reports (e.g., flow tests, daily gauge reports, royalty reports or other production reports required by state or federal regulatory bodies)."

5.4 OWS Used to Meet SPCC Secondary Containment Requirements

5.4.1 OWS Used to Meet SPCC Secondary Containment Requirements

Properly designed, maintained, and operated OWS may be used as part of a facility drainage system to meet the secondary containment requirements of the rule in §§112.7(c), 112.7(h)(1), 112.8(c)(2), 112.8(c)(11), 112.12(c)(2), and/or 112.12(c)(11). Additionally, §§112.8(b), 112.9(b), and 112.12(b) set forth design

specifications for drainage associated with secondary containment provisions at the facility. See *Chapter 4: Secondary Containment and Impracticability* for a detailed discussion of secondary containment requirements.

Standard gravity and enhanced gravity separators (*Figure 5-5* and *Figure 5-6*), or other types of OWS, may be used to meet secondary containment requirements. In this application, the separators are expected to have oil and water present in the system when there is an oil discharge or oil-contaminated precipitation runoff within the drainage area. These separators should be monitored on a routine schedule and collected oil should be removed as appropriate in accordance with procedures described in the SPCC Plan.

When designing OWS to be used as secondary containment, the SPCC Plan preparer should consider:

- The drainage area that flows to the separator;
- The corresponding anticipated flow rate of the drainage system to the separator; and
- The appropriate capacity of the OWS for oil and for wastewater.

Many OWS used for secondary containment are installed in areas where they may receive considerable flow from precipitation. If the precipitation flow rate exceeds the maximum design rate of a separator, it may discharge accumulated oil and/or untreated wastewater to navigable waters or adjoining shorelines. In this case, the separator may be an inappropriate choice for secondary containment. The specifications from OWS manufacturers outline these and other design factors as important items to consider when determining the use of a given OWS for a given application. Additionally, the manufacturer specifies the maintenance requirements to ensure proper operation of the separator.

When OWS are used to meet SPCC requirements, they must be properly operated and maintained to ensure they will perform correctly and as intended under the potential discharge scenarios it is aimed to address (e.g., §§112.7(c), 112.8(c)(2), and 112.12(c)(2)). Required OWS capacities should always be available (i.e., oil should not continually accumulate in the separators over a period of time such that the required storage capacities would not be available if an oil discharge were to occur within the drainage areas).

The use of OWS as a method of containment may be risky as they have limited drainage controls to prevent a discharge of oil and their reliability rests heavily on proper maintenance. This is particularly true when using a separator to meet the sized secondary containment requirements for large bulk storage containers, as separators are not typically designed to accommodate a worst case discharge of oil. EPA inspectors noting this containment configuration should closely inspect the device and review records associated with documenting the design criteria of the equipment and the routine maintenance performed on such equipment.

FYI – Oil/water separators used for secondary containment

When oil/water separators are used for secondary containment:

- Oil contained in the separator ***does not*** count toward facility total oil storage capacity
- Do not require additional secondary containment (i.e. tertiary containment) for the separator

Remember to observe the effluent treatment systems associated with bulk storage containers to prevent discharges to navigable waters or adjoining shorelines.

5.4.2 Applicability of the SPCC Rule to OWS Used to Meet Specific SPCC Secondary Containment Requirements

Section 112.7(c) requires "appropriate containment and/or diversionary structures or equipment to prevent a discharge as described in §112.1(b)." OWS may be used to satisfy this requirement for onshore or offshore facilities. These separators must be constructed to contain oil and prevent an escape of oil from the system prior to cleanup in order to comply with the secondary containment provision for which it is intended (§112.7(c)). A description explaining how the OWS complies with secondary containment provisions, and how it is operated and maintained, should be included in the SPCC Plan. BMPs or operation and maintenance (O&M) manuals that detail operation and maintenance procedures for OWS used specifically for secondary containment may be referenced in the SPCC Plan and maintained separately.

FYI – Location of oil/water separators

Separators used as secondary containment would typically be located in ***undiked areas***, to supplement drainage systems. The requirements for secondary containment systems described in *Section 5.4* apply.

Separators associated with a ***diked area*** which are used exclusively for treating dike discharge effluent are subject to the wastewater treatment exemption, as described in *Section 5.3*.

Section 112.7(h)(1) requires "a quick drainage system" for areas where a tank car or tank truck loading or unloading rack is present. OWS may be used as part of a quick drainage system to meet this requirement. This containment system must hold at least the maximum capacity of any single compartment of a tank car or tank truck loaded or unloaded at the facility (§112.7(h)(1)).

Sections 112.8(b), 112.9(b), and 112.12(b) set forth design specifications for drainage systems associated with secondary containment at onshore facilities. Environmentally equivalent measures can be used to satisfy these requirements (see *Chapter 3: Environmental Equivalence*, *Section 3.3.1*). For example, facilities might use ponds, lagoons, or catchment basins as part of the design of facility drainage systems. Alternatively, OWS might serve as environmentally equivalent measures to the ponds, lagoons, or catchment basins required by §§112.8(b)(3) and 112.12(b)(3). In this instance, EPA recommends that these separators be designed to handle the expected flow rate and volume of oil and water generated by facility operations. When certifying a

facility's SPCC Plan, the PE must verify that OWS are adequately designed, maintained, and operated to provide environmentally equivalent protection (in accordance with §112.7(a)(2)) under the potential discharge scenarios they are aimed to address.

Sections 112.8(c)(2), 112.8(c)(11), 112.12(c)(2), and 112.12(c)(11) require that all bulk storage containers be provided with secondary containment for "the entire capacity of the largest single container and sufficient freeboard to contain precipitation." OWS may be used to meet these requirements, but *must be appropriately sized*. These separators must be capable of handling the oil and precipitation from the general drainage area and additional oil from any accidental discharge from the largest bulk storage container located within the drainage area for which the separator provides secondary containment. Good engineering practice would suggest that the use of OWS to meet the specific secondary containment provisions be on a very limited basis and typically with smaller capacity container storage areas. See the example scenario in *Figure 5-7* that calculates the required capacity of an OWS used as secondary containment for a drum storage area.

Sections 112.8(c)(9) and 112.12(c)(9) require that the facility owner/operator observe effluent treatment facilities frequently enough to detect possible system upsets that could cause a discharge as described in §112.1(b). Separators should be monitored on a routine schedule, and collected oil should be promptly removed, as appropriate, and in accordance with manufacturers' specifications and maintenance instructions as described in the Plan, in order to ensure the proper operation and capacity of the equipment.

When OWS are used to meet secondary containment requirements, their capacities do not count toward a facility's overall storage capacity. Any volume of oil that would flow into these separators would come from another source within the drainage areas and are already counted in the facility storage capacity determination. However, slop tanks or other containers used to store waste oil that is transferred out of these separators do count toward the facility's total storage capacity. Furthermore, the SPCC rule does not require redundant secondary containment around OWS used for secondary containment (i.e., tertiary containment is not required).

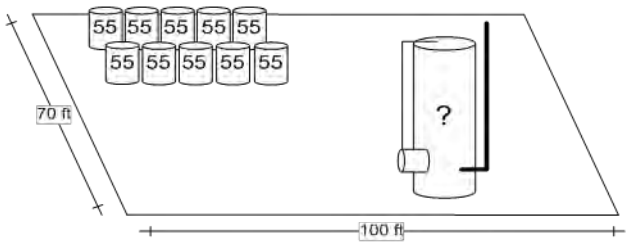
Figure 5-7: Example calculation of secondary containment for a drum storage area using an oil/water separator.

The following example includes an oil/water separator used to provide secondary containment for a drum storage area:

Scenario: An automotive facility stores up to 10 55-gallon containers of lubricating oil in its outdoor drum storage area. This undiked area drains to an oil/water separator. The total drainage area served by the oil/water separator is 70 feet x 100 feet.

Applicable secondary containment requirements: The 55-gallon containers are bulk storage containers, subject to the sized secondary containment requirements of §112.8(c)(2). In this case, the facility is using the oil/water separator to meet the secondary containment requirements. Therefore, the separator must be designed and sized to handle the capacity of the largest container in the area, plus sufficient freeboard to contain precipitation.

Note that because the drum storage area is undiked, the requirements at §112.8(b)(3) and (4) also apply.



Calculation of OWS capacity: After a review of historical precipitation data for the vicinity of the facility, the PE determined that a peak rainfall intensity is 0.6 inch per hour is the most reasonable design criterion for this undiked area, based on local conditions. The site is 100 percent impervious and therefore the full volume of precipitation that falls on the drainage surface is expected to flow into the oil/water separator.

Volume of largest container in area = 55 gallons
Drainage surface area = 70 ft x 100 ft = 7,000 ft^2
Precipitation volume (per hour) = 7,000 ft^2 x (0.6 in /12 in=0.05 ft) = 350 ft^3
Precipitation volume (per hour) in gallons = 350 ft^3 x 7.48 gal/ft^3 = 2,618 gallons
Total volume = 55 gal + 2,618 gal = 2,673 gallons
Flow rate = 2,673 gallons / 60 minutes/hour = 44.6 gallons/minute

The OWS must be capable of handling a flow-rate of 44.6 gallons per minute. Additionally, the OWS must have sufficient oil storage capacity within the unit to provide storage for 55 gallons of oil plus a reasonable safety to account for oil accumulated from the drainage area itself.

Conclusion: Based on these calculations, the facility has specified a cylindrical separator sized to handle a flow rate of 55 gallons per minute and providing a total volume of 550 gallons, including an oil storage capacity of 110 gallons prior to the recommended pump out. The oil/water separator is maintained so as to preserve storage within the unit at all times under normal operating conditions (pump out is scheduled for 35 gallons). For additional protection, the outlet of the separator is equipped with an afterbay in which absorbent materials are placed.

5.5 OWS Used in Oil Production

5.5.1 OWS Used in Oil Production

OWS are used at both onshore and offshore oil production facilities. Separation and treating installations at an oil production facility typically include equipment whose primary purpose is to separate the well fluid into its marketable or waste fractions (e.g., oil, gas, wastewater, and solids), and to treat the crude oil as needed for further storage and shipping. Separators and other separation equipment, such as heater-treaters and gun barrels, are generally used for this purpose. These flow-through process vessels are considered bulk storage containers and are subject to both the general provisions of §112.7 and applicable requirements of §112.9 for onshore oil production facilities (including bulk storage container requirements of §112.9(c)) or §112.11 for offshore oil drilling, production or workover facilities.

A variety of production equipment is used to separate and treat produced fluids. Some types of equipment are operated under low pressure conditions, while others are operated at high pressure. A process called "free-water knockout" (Figure 5-8) is generally used to separate large volumes of water from oil and gas generated from the well. A two-phase separator separates the well fluids into a liquid (oil, emulsion,[105] or water) and a gas. The liquid exits the bottom of the separator and the gas exits the top (*Figure 5-9*). Gun barrels, also called wash tanks, are generally found in older or marginal fields and are used to provide quiescent conditions and retention time to allow produced water to settle out of the well fluids (*Figure 5-10*). Three-phase separators separate well fluids into oil/emulsion, gas, and water. Gas exits from the top, oil/emulsion from the middle, and water from the bottom of this type of vertical three-phase separator (*Figure 5-11*). Three-phase separators are generally used when there is free water in the well fluids. If there is little or no free water, a two-phase separator might be used instead. Another type of equipment used to separate produced fluids, especially fluid emulsions, is termed a "heater-treater." Heater-treaters use heat, electricity, and/or chemicals to reduce the emulsion viscosity and to separate out free oil, water, and gas in oil production. OWS designs may differ from the examples provided.

FYI – Flow-through process vessels

Flow-through process vessels, such as horizontal or vertical separation vessels (e.g., heater-treater, free-water knockout, gun barrel, etc.) primarily separate the oil from other fractions (water and/or gas) and send the fluid streams to the appropriate container. The intended use of this equipment is what differentiates flow-through process vessels from other bulk and end-use storage containers, such as produced water containers. Produced water containers store well fluids (which may also contain various amounts of oil) after they have been separated and/or treated, prior to disposal or reinjection. Produced water containers are not considered flow-through process vessels; they are considered bulk storage containers when oil is present.

105 An emulsion is a colloidal suspension of a liquid within another liquid. In this case, small droplets of oil are dispersed through water.

Figure 5-8: Low pressure free-water knockout.

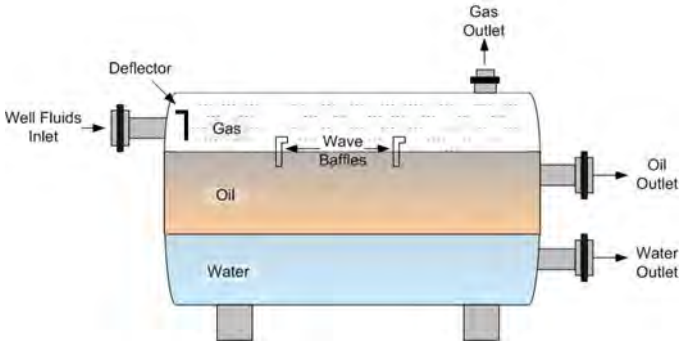


Figure 5-9: Two-phase oil/water separator.

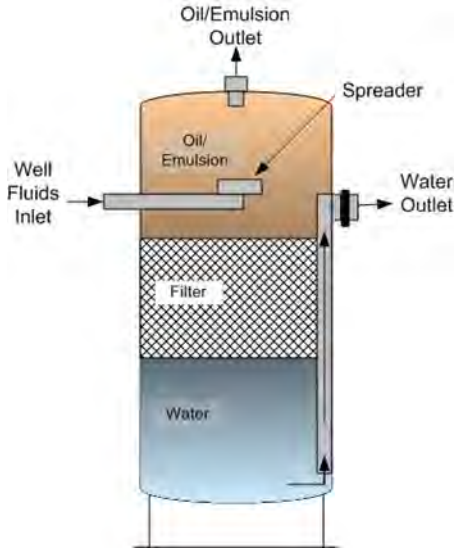


Figure 5-10: Gun barrel oil/water separator.

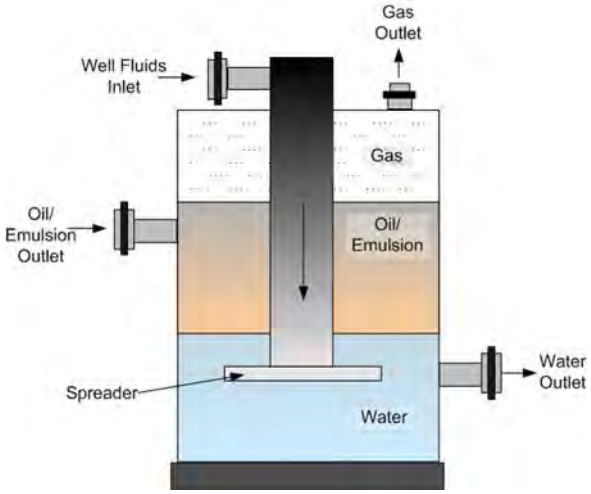
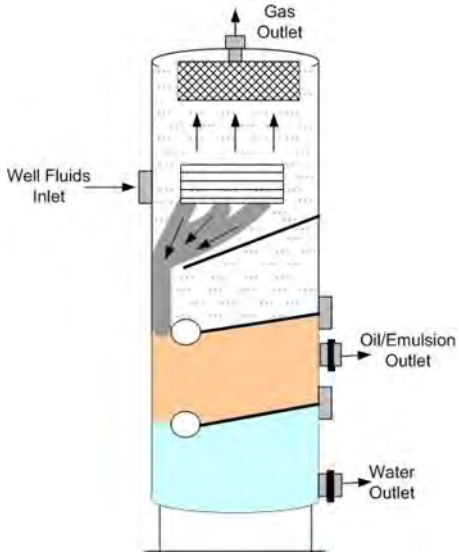


Figure 5-11: Three-phase oil/water separator.



In oil production separators, the momentum of the fluid flow is absorbed at the inlet, thereby reducing the fluid viscosity and allowing oil, gas, and water to separate out of solution. Gas then rises and flows out at the top of the separator, while oil and water fall to the lower portion of the vessel and coalesce in separate areas. With the appropriate settling time, the more dense free water settles beneath the less dense oil. Liquid levels are maintained by float-actuated control valves or dump valves. As the different pre-set liquid levels are reached, dump valves discharge water and oil from the separator to appropriate storage areas:

- Water is discharged from the bottom of the separator to a water tank;

- Oil is discharged out at a higher level to an oil storage tank; and
- Gas flows continuously out at the top of the separator to sales, a meter run, a flare, or a recovery system.

5.5.2 Applicability of the SPCC Rule to OWS Used in Onshore Oil Production

OWS used in oil production count toward the total storage capacity of the facility and must be considered when determining if a facility is regulated by the SPCC rule in accordance with §112.1(b) and (d)(2) and the definition of storage capacity in §112.2. In determining applicability of any container for calculating the total facility storage capacity, the preamble to the 2002 rule states:

> *The keys to the definition are the availability of the container for drilling, producing, gathering, storing, processing, refining, transferring, distributing, using, or consuming oil, and whether it is available for one of those uses or whether it is permanently closed. Containers available for one of the above described uses count towards storage capacity; those not used for these activities do not. Types of containers counted as storage capacity would include some flow-through separators, tanks used for "emergency" storage, transformers, and other oil-filled equipment. (67 FR 47081, July 17, 2002)*

Onshore oil production facilities with flow-through process vessel OWS (e.g., heater-treater, free-water knockout, and gun barrel) and other separation/treatment installations are required to follow the specific sized secondary containment requirements for bulk storage containers in §112.9(c)(2) and the inspection requirements of §112.9(c)(3). However, as an alternative to sized secondary containment, the facility owner or operator may provide general secondary containment in accordance with §112.7(c), and comply with the following §112.9(c)(5) provisions for flow-through process vessels at oil production facilities:

§112.9(c)(2)

Except as described in paragraph (c)(5) of this section for flow-through process vessels and paragraph (c)(6) of this section for produced water containers and any associated piping and appurtenances downstream from the container, construct all tank battery, separation, and treating facility installations, so that you provide a secondary means of containment for the entire capacity of the largest single container and sufficient freeboard to contain precipitation. You must safely confine drainage from undiked areas in a catchment basin or holding pond.

Note: The above text is an excerpt of the SPCC rule. Refer to the full text of 40 CFR part 112.

- Periodically and on a regular schedule, visually inspect and/or test flow-through process vessels and associated components (such as dump valves) for leaks, corrosion, or other conditions that could lead to a discharge, as described in §112.1(b)
- Take corrective action or make repairs to flow-through process vessels and any associated components as indicated by regularly scheduled visual inspections, tests, or evidence of an oil discharge; and

- Promptly remove or initiate actions to stabilize and remediate any accumulations of oil discharges.

It is important to note that the general secondary containment requirements under §112.7(c) still apply to flow-through process vessel OWS in addition to the alternative requirements described above. The secondary containment system must be designed to address the typical failure mode, and the most likely quantity of oil that would be discharged, and can be either active or passive in design (see *Chapter 4: Secondary Containment and Impracticability*, *Section 4.8.1*).

Furthermore, the owner/operator of the facility must install sized secondary containment and comply with bulk storage container inspection requirements (§112.9(c)(2) and (c)(3)) for flow-through process vessels within six months of a discharge(s) from flow-through process equipment as described below and a report must be submitted to the RA in accordance with the requirements of §112.4:

- More than 1,000 U.S. gallons of oil in a single discharge to navigable waters or adjoining shorelines, or
- More than 42 U.S. gallons of oil in each of two discharges to navigable waters or adjoining shorelines within any twelve month period.

This excludes discharges that are the result of natural disasters, acts of war, or terrorism. When determining the applicability of this SPCC reporting requirement, the gallon amount(s) specified (either 1,000 or 42) refers to the amount of oil that actually reaches navigable waters or adjoining shorelines not the total amount of oil spilled. EPA considers the entire volume of the discharge to be oil for the purposes of these reporting requirements.

FYI – Process equipment at non-production facilities

Similar flow-through process equipment at non-production facilities (i.e., oil-filled manufacturing equipment, such as reaction vessels, fermentors, high pressure vessels, mixing tanks, dryers, heat exchangers, and distillation columns) are not subject to the more stringent sized secondary containment and inspection requirements required for bulk storage containers; only the general secondary containment requirements at §112.7(c) apply.

Process equipment at a facility other than an oil production facility, such as at a manufacturing facility, is typically attended during hours of operation. Therefore, there is a greater potential to immediately discover and correct a discharge at non-production facilities than at oil production facilities, which are generally unattended. For this reason, EPA requires the inspection of flow-through process vessel components; prompt removal of any oil accumulations, and corrective action should a discharge occur.

See 73 FR 74277, December 5, 2008

5.5.3 Applicability of the SPCC Rule to OWS Used in Offshore Oil Production

Offshore production facilities are subject to requirements under §112.11 of the SPCC rule, which are tailored specifically for the offshore operating environment. Therefore, OWS used at off-shore oil production facilities are not eligible for the alternate compliance option in §112.9(c)(5) as described in *Section 5.5.2*. Flow-

through process equipment at offshore facilities are subject to the general requirements of the SPCC rule under §112.7, including the secondary containment requirement in §112.7(c).

OWS used in offshore oil production are also subject to the provisions of §112.11(b) and (d) to prevent a discharge of oil. However, if other provisions of the rule (except secondary containment) can be met through alternative methods that provide environmental equivalence for this equipment, then the Plan must include a description in accordance with §112.7(a)(2).

Vessels and equipment, such as glycol dehydrators and inline heaters that treat only gas and that do not separate, treat, or contain oil, are not subject to the SPCC rule.

§112.11(b)

Use oil drainage collection equipment to prevent and control small oil discharges around pumps, glands, valves, flanges, expansion joints, hoses, drain lines, separators, treaters, tanks, and associated equipment. You must control and direct facility drains toward a central collection sump to prevent the facility from having a discharge as described in §112.1(b). Where drains and sumps are not practicable, you must remove oil contained in collection equipment as often as necessary to prevent overflow.

§112.11(d)

At facilities with areas where separators and treaters are equipped with dump valves which predominantly fail in the closed position and where pollution risk is high, specially equip the facility to prevent the discharge of oil. You must prevent the discharge of oil by:

(1) Extending the flare line to a diked area if the separator is near shore;

(2) Equipping the separator with a high liquid level sensor that will automatically shut in wells producing to the separator; or

(3) Installing parallel redundant dump valves.

Note: The above text is an excerpt of the SPCC rule. Refer to the full text of 40 CFR part 112.

5.5.4 Wastewater Treatment Exemption and Produced Water

At oil drilling and oil production facilities, treatment units subject to the rule include produced water containers, open oil pits or ponds associated with oil production operations, OWS (e.g., gun barrels), and heater-treater units. Open oil pits or ponds function as another form of bulk storage container and are not used for wastewater treatment (67 FR 47068, 47069, July 17, 2002). Therefore, as a type of oil treatment equipment, oil water separators at production facilities are not eligible for the wastewater treatment exemption.

The SPCC rule's wastewater treatment exemption specifically states that the production of oil is not wastewater treatment for the purposes of §112.1(d)(6). The goal of an oil production, oil recovery, or oil recycling facility is to maximize the production or recovery of oil, while eliminating water and other impurities in the oil, whereas the goal of a wastewater treatment facility is to purify water. Neither an oil production facility nor an oil recovery or recycling facility treats water; instead, it treats oil. Treatment of produced water and oil mixtures is not considered wastewater treatment, and thus the wastewater treatment exemption does not apply.

Additionally, oil production facilities generally lack NPDES or state-equivalent permits or prevention requirements, and thus lack the protections that such permits provide. Underground Injection Control (UIC) permits do not have surface water prevention requirements for

§112.2

Produced water container means a storage container at an oil production facility used to store the produced water after initial oil/water separation, and prior to reinjection, beneficial reuse, discharge, or transfer for disposal.

Note: The above text is an excerpt of the SPCC rule. Refer to 40 CFR part 112 for the full text of the rule.

production facilities. Production facilities are normally unattended and therefore lack constant human oversight and inspection. Produced water generated in the production process normally contains saline water as a contaminant in the oil, which in addition to the toxicity of the oil might aggravate environmental conditions in the case of a discharge (67 FR 47068, July 17, 2002). In some areas of the United States, produced water is fresh and may be discharged for beneficial use (e.g., irrigation or water for livestock) in accordance with federal and state regulatory requirements.

Therefore, a facility that stores, treats, or otherwise uses produced water remains subject to the rule. Produced water containers at onshore oil production facilities are bulk storage containers and are therefore subject to the applicable requirements in §112.9(c), including the requirement for sized secondary containment. The SPCC rule includes an alternative compliance option for produced water containers at onshore oil production facilities in lieu of sized secondary containment.

For more information on the applicability of the SPCC rule as it relates to oil and water mixtures in produced water or produced water containers, *see Chapter 2: SPCC Rule Applicability*, *Sections 2.2.7* and *2.10.7*. For information on the secondary containment requirements that apply to produced water containers including the alternative regulatory requirements, see *Chapter 4: Secondary Containment and Impracticability*, *Section 4.8.2*.

5.6 OWS Used in Oil Recovery or Recycling Facilities

Oil recycling and recovery activities that collect and consolidate production fluids from multiple oil production facilities in an effort to further recover and treat oil prior to the disposal of production fluids are not eligible for the wastewater treatment exemption because the operations focus on oil treatment rather than wastewater treatment.

These include facilities that are typically discrete and not associated (co-located) with an oil production facility. Operations typically specialize in the treatment of production fluids or other oil recovery activities, and may include disposal, and injection of production fluids. A second type of oil recycling operation that is not eligible for the wastewater treatment exemption includes waste oil recyclers and facilities engaged in the recovery and/or recycling of motor oils, other petroleum oils, and AFVOs.

OWS located at oil recovery or recycling facilities are subject to the provisions of §112.7 and applicable provisions of §112.8(b) and (d) for onshore petroleum and non-petroleum facilities or §112.12(b) and (d) for onshore AFVO facilities. The §§112.8(c) and 112.12(c) provisions (such as sized containment, integrity testing and overfill prevention) for bulk storage containers do not apply because OWS at these facilities function as oil-filled manufacturing equipment and are not bulk storage containers. When OWS are part of a flow-through process, such as that found during oil recovery or recycling activities, OWS are considered oil-filled manufacturing equipment and are excluded from §§112.8(c) and 112.12(c) requirements because they are excluded from the definition of a *bulk storage container* as defined in §112.2 of the rule. However, containers used to store recovered or recycled oil collected from the OWS are bulk storage containers. These bulk storage containers must comply with the §§112.8(c) and 112.12(c) provisions and other applicable requirements.

For OWS used in oil recovery or recycling, the OWS are considered oil-filled manufacturing equipment and are subject to the provisions of §112.7 and applicable provisions of §112.8(b) and (d) for onshore petroleum and non-petroleum facilities or §112.12(b) and (d) for onshore AFVO facilities. The Plan must address the general requirements under §112.7 for the OWS including a description of how the facility complies with the secondary containment requirement under §112.7(c).

5.7 Documentation Requirements and the Role of the EPA Inspector

5.7.1 Documentation by Owner/Operator

OWS used exclusively for wastewater treatment are exempt from all SPCC requirements, and no documentation is required for this equipment in the SPCC Plan.

For OWS used to meet SPCC secondary containment requirements, the SPCC Plan should discuss the separator design capacity, configuration, maintenance, operation, and other elements of the drainage systems that ensure proper functioning and containment of the oil as required by §112.7(a)(3)(iii). Examples of elements that this discussion should include are:

- The presence and configuration of OWS outlets and the presence of other equipment to prevent the accidental release of oil;
- Routine visual inspection of the oil/water separator, its contents, and discharges of effluent;
- Preventive maintenance of facility equipment affecting discharge, including the removal of settled pollutants and collected oil;
- A drainage area that flows to the OWS and corresponding anticipated flow rate of the drainage system to the separator;
- Appropriate capacity of the OWS for oil, wastewater, and, if appropriate, precipitation;
- Provisions for adequate separate storage capacity (based on the containment sizing required by the rule) to contain oil recovered in the oil/water separator; and
- Documentation associated with the maintenance and inspection of OWS.

A separate bulk storage container used to store oil following separation in any OWS (i.e., wastewater treatment, secondary containment, or oil production) is subject to all applicable requirements of 40 CFR part 112, including §§112.8(c), 112.9(c), or 112.12(c) as appropriate.

For OWS used in oil production, the OWS are bulk oil storage containers to be included in the SPCC Plan. The location of these containers must be indicated on the facility diagram and discussed in the general requirements in accordance with §112.7(a)(3). For more information on facility diagrams, refer to *Chapter 6: Facility Diagram and Description*. The Plan must also include a discussion of sized secondary containment

provided for OWS (§112.9(c)(2)), or, in the case where the owner/operator elects to comply instead with the alternate requirements in §112.9(c)(5), include records to document implementation of the alternative measures, including periodic inspection and/or testing for leaks, corrosion, or other conditions that could lead to a discharge as described in §112.1(b); corrective action or repairs to flow-through process vessels and any associated components as indicated by regularly scheduled visual inspections, tests, or evidence of an oil discharge; and prompt removal or initiation of actions to stabilize and remediate any accumulations of oil discharges associated with flow-through process vessels. The Plan must also address the general requirements under §112.7 for OWS including a description of how the facility complies with the secondary containment requirement under §112.7(c).

5.7.2 Role of the EPA Inspector

As with other aspects of the SPCC Plan, the certifying PE will review the use of and applicable requirements for OWS at a facility and ensure that they are consistent with good engineering practice. In the case of a qualified facility, the owner operator will make a similar certification and ensure that the Plan is in accordance with accepted and sound industry practices and standards.

The EPA inspector will verify that any OWS at a facility that are not addressed in the SPCC Plan are in fact used exclusively for wastewater treatment and not to meet any requirement of part 112. This review considers how the OWS is being used at the facility. The EPA inspector should consider the intended use of the separator at the facility (e.g., wastewater treatment, secondary containment, oil production, recovery, or recycling), any flow diagrams illustrating the use of the separator, and the design specifications of the unit in evaluating whether the OWS is eligible for the wastewater exemption. The EPA inspector may also consider the flow-through capacity of the separator, the nature of the oil to be separated (e.g., whether it is an emulsion), and the design specifications of the unit in evaluating the use of the oil/water separator.

For each OWS used to meet SPCC secondary containment requirements, the EPA inspector will verify that the Plan includes a discussion of the separator design capacity, configuration, maintenance, and operation, as well as other elements of the drainage systems that ensure proper functioning and containment of the oil in accordance with §112.7(c), §112.8(c)(2), or §112.12(c)(2). Particularly large drainage areas served by an OWS to meet secondary containment requirements may raise a “red flag” given the large volume of precipitation that may need to be handled by the OWS concurrently with an oil discharge; the inspector should verify that the Plan adequately addresses the ability of the OWS to handle the expected precipitation (considering expected rainfall intensity) and discharge volume given the design treatment flow rate and OWS capacity.

EPA inspectors should note the risk associated with this form of containment and should review the information provided in the Plan regarding the design, maintenance, operation, and efficacy of OWS systems used for containment very carefully. These separators should be monitored on a routine schedule, and collected oil should be promptly removed as appropriate and in accordance with manufactures specifications and maintenance instructions as described in the Plan in order to ensure the proper operation and capacity of the equipment.

OWS (including those used in oil production) that are not eligible for the wastewater exemption must be included in the oil storage capacity calculations for the facility (§112.1(b) and (d)(2) and the definition of storage capacity in §112.2).

When an oil production facility Plan describes compliance with the alternative option for flow-through process vessels in accordance with §112.9(c)(5), then the EPA inspector should verify that the requisite records are included in the SPCC Plan (refer to *Section 4.8.1* and *7.2.9* for a summary of the information to be provided in the Plan).

If the owner or operator of the facility discharges into or upon a navigable water or adjoining shoreline more than 1,000 U.S. gallons of oil in a single discharge, or more than 42 U.S. gallons of oil in each of two discharges within a 12-month period from a flow-through process vessel, and is required to comply with §112.9(c)(2) and 112.9(c)(3), the SPCC Plan must then describe the sized secondary containment and inspection program provided for this equipment.

By certifying the SPCC Plan, a PE attests that the Plan has been prepared in accordance with good engineering practice and with the requirements of 40 CFR part 112, and that the Plan is adequate for the facility. Thus, if OWS uses are properly documented, they most likely will be considered acceptable by EPA inspectors. However, if the documented uses of the OWS appear inappropriate to prevent spills from reaching navigable waters or adjoining shorelines, appear to be incorrect, deviate from the use described in the Plan, are not maintained or operated in accordance with the Plan, or the separator appears to be malfunctioning or out of service, further follow-up action may be warranted. This may include requests for more information or for a Plan amendment in accordance with §112.4(d).

Chapter 6 Facility Diagram and Description

6.1 Introduction

Section 112.7(a)(3) of the SPCC rule requires that facility owners/operators include in the SPCC Plan a description of the facility, including a facility diagram that marks the location and contents of each fixed oil storage container and the storage area where mobile or portable containers are located. The facility diagram must also include all transfer stations and connecting pipes. The facility diagram is important because it is used for effective prevention, planning, management (for example, inspections), and response considerations. The diagram also will help the facility and emergency response personnel to plan for emergencies.

The rule also requires a description of the facility's oil storage containers, including their content and capacity. Providing information on a container-specific basis helps the owner or operator of the facility to prioritize inspections and maintenance of containers based on characteristics such as age, capacity, or location and helps to formulate contingency planning, if such planning is necessary. This information also helps inspectors to prioritize inspections of higher-risk containers at a facility and verify the facility capacity calculation. This chapter explains these requirements, provides guidelines on the necessary level of detail, discusses the discretion of the certifying PE or owner/operator in preparing the diagram, and includes several facility diagrams as examples.

Additionally, the SPCC Plan must also address discharge prevention measures; discharge or drainage controls; countermeasures for discharge discovery, response, and cleanup; methods of disposal of recovered materials; and specific contact information (see Section 112.7(a)(3) for more information on these requirements).

This chapter is organized as follows:

- ***Section 6.2*** outlines requirements for providing a general facility description that includes the physical layout, discharge prevention measures, drainage controls and countermeasures.
- ***Section 6.3*** describes the type of information that is necessary to enable a person to report a discharge to navigable waters or adjoining shorelines.
- ***Section 6.4*** describes the requirements for the facility diagram and specific types of containers.
- ***Section 6.5*** provides several examples of facility diagrams.
- ***Section 6.6*** describes the EPA inspector's role in reviewing facility diagrams.

6.2 General Facility Description

Section 112.7(a)(3) requires that the Plan include a description of the physical layout of the facility. This description may include information on the facility's location, type, size, geographic and topographic characteristics, and proximity to navigable waters, as well as other relevant information. This general facility description is supplemented with a more specific description of containers subject to the SPCC rule to complement what is illustrated on the facility diagram. This description must be included in the SPCC Plan regardless of whether similar information is available in the FRP or other facility plans. If the SPCC Plan does not follow the sequence of the rule, then a cross-reference is required.

6.2.1 Oil Types and Container Capacities

Section 112.7(a)(3)(i) requires that the Plan include the type of oil in each fixed container and its storage capacity. For mobile or portable containers, EPA provides flexibility in allowing the Plan preparer to either provide the type of oil and storage capacity for each container, or provide an estimate of the potential number of mobile or portable containers, the types of oil, and anticipated storage capacities.

The Plan preparer may identify an area on the facility diagram (e.g., a drum storage area) and include a separate description of the total number of containers, capacities, and contents in the Plan or reference facility inventories that can be updated by facility personnel. The Plan should include an estimate of the number of mobile or portable containers expected to be stored in an area and the capacity of each container. This estimate can be used to determine the applicability of the rule thresholds and provide a general description of the mobile/portable containers in the Plan (72 FR 58389, October 15, 2007). This estimate may be represented as a capacity range. For example, a facility with a 55-gallon drum inventory that fluctuates between 10 and 100 drums would represent a capacity range of 550 gallons to 5,500 gallons in the SPCC Plan.

6.2.2 Discharge Prevention Measures

The facility owner/operator must include in the SPCC Plan a discussion of discharge prevention measures including procedures for routine handling of products (loading, unloading, and facility transfers,

§112.7(a)(3)

... You must also address in your Plan:
(i) The type of oil in each fixed container and its storage capacity. For mobile or portable containers, either provide the type of oil and storage capacity for each container or provide an estimate of the potential number of mobile or portable containers, the types of oil, and anticipated storage capacities;

(ii) Discharge prevention measures including procedures for routine handling of products (loading, unloading, and facility transfers, etc.);

(iii) Discharge or drainage controls such as secondary containment around containers and other structures, equipment, and procedures for the control of a discharge;

(iv) Countermeasures for discharge discovery, response, and cleanup (both the facility's capability and those that might be required of a contractor);

(v) Methods of disposal of recovered materials in accordance with applicable legal requirements; and

(vi) Contact list and phone numbers for the facility response coordinator, National Response Center, cleanup contractors with whom you have an agreement for response, and all appropriate Federal, State, and local agencies who must be contacted in case of a discharge as described in §112.1(b).

Note: The above text is an excerpt of the SPCC rule. Refer to 40 CFR part 112 for the full text of the rule.

etc.). Including this information in the SPCC Plan will help to train new facility personnel on the discharge prevention measures to be employed at the facility and be useful for refresher training during annual discharge prevention briefings.

6.2.3 Drainage Controls

The Plan must also include a discussion of discharge or drainage controls such as secondary containment around containers and other structures, equipment, and procedures for the control of a discharge.

The general secondary containment provision of §112.7(c) requires that secondary containment and/or diversionary structures be appropriate to prevent a discharge to navigable waters or adjoining shorelines. The owner/operator should discuss the method, design, and capacity for secondary containment that he chooses to address the typical failure mode, and the most likely quantity of oil that would be discharged. The entire containment system, including walls and floor, must be capable of containing oil and must be constructed so that any discharge from a primary containment system, such as a tank, will not escape the containment system before cleanup occurs. The discussion should also include whether the secondary containment is either active or passive in design. If an active containment measure is employed, then the discussion should describe the equipment, procedures and personnel that will be necessary to effectively employ the active containment measure to prevent a discharge to navigable waters or adjoining shorelines.

Loading and unloading racks should have containment that flows to catchment basins or a treatment facility designed to handle discharges. Otherwise, the facility can include a quick drainage system for tank car or tank truck loading/unloading racks. Any containment system to address the loading/unloading rack must hold at least the maximum capacity of any single compartment of a tank car or tank truck loaded or unloaded at the facility.

Finally, the description for bulk storage containers should address whether the secondary containment is sized to contain the capacity of the largest single container within the containment system with sufficient freeboard for precipitation.

6.2.4 Countermeasures

Include in the SPCC Plan a discussion of the facility’s countermeasures for discharge discovery, response, and cleanup (both the facility's capability and those that might be required of a contractor). These countermeasures may include procedures for responding to a discharge that is discovered before it reaches navigable waters or adjoining shorelines (active containment measures used as part of a secondary containment strategy) as well as additional procedures for responding after a discharge reaches navigable waters or adjoining shorelines (contingency planning).

6.2.5 Disposal Methods

The SPCC rule requires that the owner/operator of the facility discuss the methods to be used to dispose of recovered materials in the event of a discharge. By describing those methods in the Plan, the owner/operator

demonstrates that the facility has done the appropriate planning to be able to dispose of recovered materials, should a discharge occur.

Proper disposal of recovered materials helps prevent a discharge as described in §112.1(b) by ensuring that the materials are managed in an environmentally sound manner. Proper disposal also assists response efforts. If the owner or operator of a facility lacks adequate resources to dispose of recovered oil and oil-contaminated material during a response, it limits how much and how quickly oil and oil-contaminated material is recovered, thereby increasing the risk and damage to the environment.

6.2.6 Contact List

The SPCC Plan must include a contact list that includes phone numbers for the facility response coordinator, National Response Center, cleanup contractors with whom the owner/operator has an agreement for response, and all appropriate Federal, State, Tribal and local agencies who must be contacted in case of a discharge to navigable waters or adjoining shorelines.

A contact list is necessary for both preparedness and response purposes because it enables the facility personnel to begin mobilizing resources immediately upon the discovery of a discharge to navigable waters or adjoining shorelines. The information included in the contact list should be reviewed periodically to ensure that the information is current.

6.3 Notification Requirements

The SPCC rule identifies the type of information to include in the SPCC Plan that is necessary to enable a person to report a discharge to navigable waters or adjoining shorelines. The owner/operator of the facility should report discharges to the National Response Center (NRC) at 1-800-424-8802 or for those without "800" access 1-202-267-2675. The NRC is the federal government's centralized reporting center, which is staffed 24 hours per day by U.S. Coast Guard personnel (for more information see http://www.nrc.uscg.mil/). If reporting directly to NRC is not practicable, reports also can be made to the EPA regional office or the U.S. Coast Guard Marine Safety Office (MSO) in the area where the incident occurred.

The following information will be requested by the NRC:

- The exact address or location and phone number of the facility;

§112.7(a)(4)

Unless you have submitted a response plan under §112.20, provide information and procedures in your Plan to enable a person reporting a discharge as described in §112.1(b) to relate information on the exact address or location and phone number of the facility; the date and time of the discharge, the type of material discharged; estimates of the total quantity discharged; estimates of the quantity discharged as described in §112.1(b); the source of the discharge; a description of all affected media; the cause of the discharge; any damages or injuries caused by the discharge; actions being used to stop, remove, and mitigate the effects of the discharge; whether an evacuation may be needed; and, the names of individuals and/or organizations who have also been contacted.

Note: The above text is an excerpt of the SPCC rule. Refer to 40 CFR part 112 for the full text of the rule.

- The date and time of the discharge, the type of material discharged;
- Estimates of the total quantity discharged;
- Estimates of the quantity discharged to navigable waters or adjoining shorelines;
- The source of the discharge;
- A description of all affected media;
- The cause of the discharge;
- Any damages or injuries caused by the discharge;
- Actions being used to stop, remove, and mitigate the effects of the discharge;
- Whether an evacuation may be needed; and
- The names of individuals and/or organizations who have also been contacted.

The same requirements for spill reporting are part of the FRP rule under 40 CFR 112.20; therefore, if a facility has prepared and submitted an FRP to the EPA Regional Administrator, then the SPCC Plan does not need to include a section on notifications.

6.4 Preparing a Facility Diagram

6.4.1 Purpose

The facility diagram is an important component of an SPCC Plan. It is used for prevention, planning, inspections, management, and response considerations. In most cases, the owner or operator of the facility will work with the PE certifying the SPCC Plan to identify the information to include on the facility diagram. The rule requires that the diagram identify the location and contents of each fixed oil storage container and location of mobile and portable container storage areas (§112.7(a)(3)). Diagrams may help responders avoid certain hazards by informing them of the location and content of containers and of the response equipment. The facility diagram may also assist responders in determining the flow pathway of discharged oil and to take more effective measures to control the flow of oil to potentially avert damage to sensitive environmental areas; protect drinking

§112.7(a)(3)

Describe in your Plan the physical layout of the facility and include a facility diagram, which must mark the location and contents of each fixed oil storage container and the storage area where mobile and portable containers are located. The facility diagram must identify the location of and mark as "exempt" underground tanks that are otherwise exempted from the requirements of this part under §112.1(d)(4). The facility diagram must also include all transfer stations and connecting pipes, including intra-facility gathering lines that are otherwise exempted from the requirements of this part under §112.1(d)(11).

Note: The above text is an excerpt of the SPCC rule. Refer to 40 CFR part 112 for the full text of the rule.

water sources; and prevent discharges to other conduits, to a treatment facility, or to navigable waters or adjoining shorelines. Federal and state facility inspectors and facility personnel need to be aware of the location of all containers, piping, and transfer areas subject to the SPCC rule. The diagram may also be used to visually address other rule requirements such as discharge/drainage controls and the flow path of a discharge (§112.7(a)(3)(iii) and 112.7(b), respectively). Additionally, the diagram may be attached to a facility inspection checklist to identify areas, containers, or equipment subject to inspection.

6.4.2 Tier I Qualified Facility Exclusion

In 2008, EPA promulgated streamlined requirements for that exclude the requirement for a facility diagram. This subset of qualified facilities (i.e., those with no individual container greater than 5,000 U.S. gallons in capacity) is eligible to complete an SPCC Plan template that follows the format outlined in Appendix G of the SPCC rule. EPA determined that a facility diagram is not necessary because this type of facility is typically small and generally simple in configuration. A facility diagram is not needed to understand the facility layout and locate areas of potential discharge at such facilities.

The facility diagram exclusion applies only for Tier I qualified facilities. The owner or operator of a Tier II qualified facility is required to develop and certify an SPCC Plan that complies with all of the applicable requirements of section §112.7 and subparts B and C of the rule. For more information on qualified facilities see the discussion in *Chapter 1: Introduction, Sections 1.3.3 and 1.3.4*. Additional guidance is also available for qualified facility owners/operators at http://www.epa.gov/oem/content/spcc/spcc_qf.htm

6.4.3 Requirements for a Facility Diagram

The facility diagram is one of the general requirements for an SPCC Plan. Facility diagrams provided as part of an SPCC Plan illustrate a variety of information. The following items are required by §112.7(a)(3):

- Aboveground storage tanks (including location and contents);
- Underground storage tanks (including location and contents). This includes those that are subject to the SPCC rule or those that are exempt (see *Section 6.4.7*);
- Storage area(s) where mobile or portable containers are located (see *Section 6.4.6*);
- Transfer stations such as oil transfer areas including loading/unloading racks and loading/unloading areas;
- Oil-filled equipment such as hydraulic operating systems or manufacturing equipment (including location and contents);
- Oil-filled electrical transformers, circuit breakers, or other equipment (including location and contents);
- Connecting piping (if the scale of drawing permits, as discussed in *Section 6.4.9*);

- Oil pits or ponds (at oil production facilities);
- Oil production facility stock tanks, separation equipment and produced water containers;
- Any other bulk storage or oil-filled operational equipment at an oil production facility; and
- Flowlines and intra-facility gathering lines at a production facility (this includes those that are subject to the SPCC rule and exempt intra-facility gathering lines subject to the requirements of 49 CFR part 192 or 195 as described in §112.1(d)(11)).

Containers that have a capacity of less than 55 gallons, are permanently closed, or are otherwise exempt from the rule (with the exception of exempt underground tanks and exempt intra-facility gathering lines) are not required to be identified on the facility diagram.

In addition, EPA recommends (but does not require under the SPCC rule) that the following information be included on the facility diagram to maximize its utility for facility personnel, emergency responders, and inspectors:

- Aboveground storage tank capacities and/or tank identification numbers or letters;
- Secondary containment structures, including oil/water separators used for containment;
- Storm drain inlets and surface waters that could be affected by a discharge;
- Direction of flow in the event of a discharge (which can serve to address the SPCC requirement under §112.7(b));
- Legend that indicates scale and identifies symbols used in the diagram;
- Location of response kits or other equipment used to implement an active containment strategy:
- Location of firefighting equipment and pipe stands for foam application;
- Location of valves or drainage system control that could be used in the event of a discharge to contain oil on the site;
- The location of important piping appurtenances such as valves, checks or other piping-related equipment (to aid in facility response and inspection efforts);
- Compass direction indicating north; and
- Topographical information and area maps.

For purposes of emergency response, EPA recommends, but does not require, that an owner/operator mark on a facility diagram containers that store Clean Water Act (CWA) hazardous substances (listed in 40 CFR part 116, Designation of Hazardous Substances) and label the contents of these containers (67 FR 47097, July 17, 2002).

While recognizing that SPCC Plans and their associated diagrams are facility-specific and prepared within the discretion granted to the Plan preparer, the information provided in this chapter is meant to facilitate a common understanding of what EPA inspectors may expect to see in a facility diagram. The remainder of this section provides guidelines for the recommended level of detail, how specific containers and systems may be addressed and the use of various approaches to develop facility diagrams that meet the requirements of §112.7(a)(3).

6.4.4 Level of Detail

The facility diagram should provide sufficient detail for the facility personnel to undertake prevention activities, for EPA to perform an effective inspection, and for responders to take effective measures. As with other aspects of the SPCC Plan, the facility diagram is to be prepared in accordance with good engineering practice. Thus, the level of detail provided and the approach taken for preparing an adequate facility diagram is primarily at the discretion of the person certifying the SPCC Plan.

The scale and level of detail shown on a facility diagram may vary according to the needs and complexity of the facility (72 FR 58389, October 15, 2007). Owners or operators of a facility may represent complicated areas of piping or oil-filled equipment in a less detailed manner on the facility diagram in the SPCC Plan, as long as the information is contained in more detailed diagrams of the systems or is contained in some other form and such information is maintained elsewhere at the facility and this location is referenced in the SPCC Plan (73 FR 74247, December 5, 2008). For example, a facility owner or operator may indicate in the diagram an area where complicated oil-filled equipment (such as manufacturing equipment found in a refinery or other oil processing facility) is located and provide a table in the Plan describing the type(s) of equipment and contents of the oil storage containers.

The facility diagram must include all fixed and mobile/portable containers (including oil-filled equipment) that store 55 gallons or more of oil and identify the contents of these containers (§112.7(a)(3)). (The SPCC rule exempts containers with a capacity less than 55 gallons, and therefore they should not be included on the facility diagram.) The following sections provide information on identifying mobile or portable containers, completely buried storage tanks, and piping and manufacturing equipment on the facility diagram.

6.4.5 Fixed Storage Containers

In 2008, EPA amended the SPCC rule to clarify that the facility diagram must include the location of all containers located in a *fixed* position (i.e., those that do not move around the facility). In situations where diagrams become complicated due to the presence of multiple oil storage containers, it may be difficult to indicate the contents of the containers on the diagram itself. In order to simplify the diagram, the owner or operator may choose to include the contents of the containers separately in the SPCC Plan in an accompanying

table or key. See *Section 6.2.1* for more information on the requirement to describe the facility's oil storage containers, including contents and capacity

6.4.6 Mobile or Portable Containers

The owner/operator must mark the storage area of mobile or portable containers on the facility diagram (§112.7(a)(3)). Mobile or portable containers should be marked on the facility diagram in their out-of-service or designated storage area, primary storage areas, or areas where they are most frequently located (see 73 FR 74247, December 5, 2008). Thus, if containers are stored in one area and operated in another area, both "areas" would be identified on the facility diagram. However, since the rule requires the identification of a "storage area", these "areas" may be marked as general locations on the diagram rather than identify specific discrete locations for each mobile or portable container. Regardless of where mobile or portable containers are located at the facility, the owner/operator must comply with the specific secondary containment requirements for these containers as described in §§112.8(c)(11) and 112.12(c)(11). See *Chapter 4: Secondary Containment and Impracticability, Section 4.7.5* for a discussion of these requirements.

For mobile or portable containers (e.g., drums, IBCs and totes), the facility owner/operator may note the general contents of each container and provide more detailed content information separately (such as on a separate sheet, log, or electronic system). If the contents of a container change frequently, the contents may be recorded separately, or on the diagram. If the information is provided separately, the diagram should note that contents vary. See *Section 6.2.1* for more information on the requirement to describe the facility's oil storage containers, including contents and capacity.

Tip – Mobile or portable containers

While the SPCC rule does not specifically define "mobile" or "portable" containers, such containers may include 55-gallon drums, skid tanks, totes, Intermediate Bulk Containers (IBCs), and other small containers put into place and later moved. Mobile/portable maintenance tanks, and some oil refinery tank trucks and fueling trucks dedicated to a particular facility (such as a construction site, military base, or similar large facility) may also fall under this category.

(73 FR 74246-7, December 5, 2008)

6.4.7 Underground Storage Tanks

A facility diagram must include the location and contents of *all* containers addressed in the SPCC Plan (67 FR 47097 and §112.7(a)(3)). This requirement includes both exempt underground storage tanks (USTs) and USTs that are subject to SPCC requirements. Completely buried USTs and piping systems that are subject to all technical requirements of either 40 CFR part 280 or an approved state UST program under 40 CFR part 281 are exempt from SPCC requirements. However, USTs must be included in the facility diagram and marked "exempt" if the facility is otherwise subject to the SPCC rule. Similarly, the SPCC rule exempts USTs including below-grade vaulted tanks that supply emergency diesel generators at a nuclear power generation facility licensed by the Nuclear Regulatory Commission (see *Chapter 2: SPCC Rule Applicability, Section 2.8.4*). Such emergency generator tanks must be included in the facility diagram and marked "exempt" if the facility is otherwise subject to the SPCC rule. This information will help response personnel to easily identify dangers from fire, explosion, or physical impediments during response activities.

As discussed in *Chapter 2: SPCC Rule Applicability, Section 2.8.3*, a facility may have USTs that are subject to SPCC requirements because they are deferred from compliance with some or all of the technical requirements of 40 CFR part 280 (e.g., UST systems with field constructed tanks and airport hydrant fuel distribution systems). USTs that are subject to SPCC requirements must be marked on the facility diagram (§112.7(a)(3)). (See 56 FR 54612, October 22, 1991.)

6.4.8 Intra-facility Gathering Lines

The facility diagram must include all transfer stations (i.e., any location where oil is transferred) and connecting pipes, including intra-facility gathering lines that are otherwise exempted from SPCC requirements (§112.7(a)(3)). Although the SPCC rule exempts those intra-facility gathering lines that are subject to the regulatory requirements of 49 CFR part 192 or 195, their location must be identified and marked as "exempt" on the facility diagram (§112.1(d)(11)). This will assist facility, EPA, and emergency personnel to review the facility's SPCC Plan and identify hazards during a spill response activity.

6.4.9 Piping and Oil-filled Equipment

Oil-filled equipment (such as manufacturing equipment) and associated piping present at an SPCC-regulated facility may be difficult to represent on a facility diagram, due to their relative location, complexity, or design. Recognizing this, EPA allows flexibility in the way the facility diagram is drawn. An owner/operator may represent such systems in a less detailed manner on the facility diagram as long as more detailed drawings are maintained at the facility and referenced in the SPCC Plan. More detailed drawings may include blueprints, engineering diagrams, or diagrams developed to comply with other local, state, or federal requirements.

The scale and level of detail of the facility diagram may make it difficult to show small transfer lines or piping within containment structures. Schematic representations that provide a general overview of the piping service (e.g., supply/return) may provide sufficient information when combined with a description of the piping in the Plan. Alternatively, overlay diagrams showing different portions of the piping system may be used where the density and/or complexity of the piping system would make a single diagram difficult to read (73 FR 74248, December 5, 2008). Although the SPCC rule requires that piping be included on the facility diagram, it is not necessary to include appurtenances associated with the piping.

Figure 6-1 and *Figure 6-2* demonstrate simplified examples of oil-filled equipment and piping as shown in a complete facility diagram in *Figure 6-4*. Examples of ways that oil-filled manufacturing equipment may be represented include a box that identifies the equipment and its location, or a simplified process flow diagram. For areas of complicated piping, which often include different types, numbers, and lengths of pipes, the facility diagram may show a simplified box labeled "piping" or show a single line that identifies the service (e.g., supply/return), as long as more detailed diagrams are available at the facility (73 FR 74248, December 5, 2008).

Figure 6-1: Example of a facility diagram showing how manufacturing equipment could be represented. Note that more detailed diagrams would need to be available at the facility.

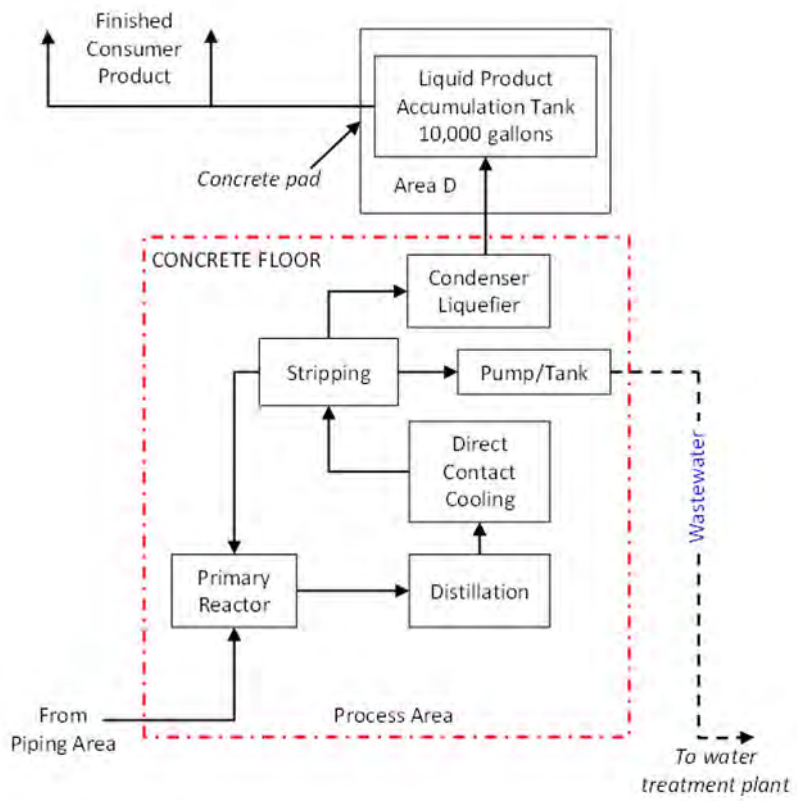
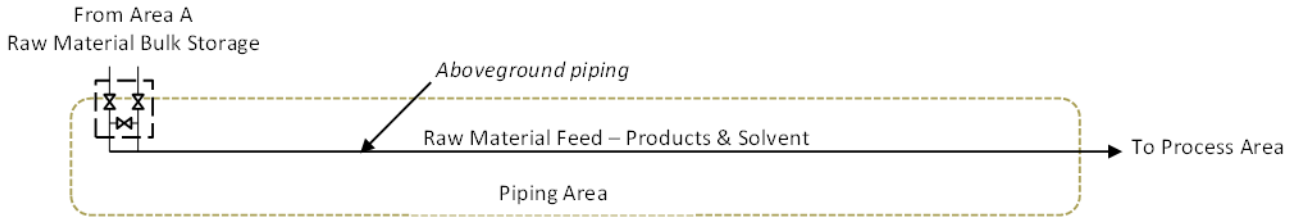


Figure 6-2: Example showing how a complex piping area could be represented in a facility diagram. Note that more detailed diagrams would need to be available at the facility.



6.4.10 Use of Diagrams Created for Other Programs or Uses

EPA does not require that a facility diagram be developed exclusively for the SPCC Plan. Some state and other federal regulations may require a diagram with similar or overlapping requirements. States may supplement the SPCC minimum requirements with more stringent requirements. A facility diagram prepared for a state or other federal plan (including the FRP requirements under §112.20) or for other purposes (e.g., as-built plans, construction permits, facility modifications, and other pollution prevention requirements) may be used in an SPCC Plan if it meets the requirements of the SPCC rule (e.g., it includes the contents of the containers, transfer areas, and piping) (73 FR 74247, December 5, 2008). Similarly, facilities with oil-filled electrical equipment may base their facility diagrams on existing electrical one-line diagrams, provided the drawings are appended as necessary to include all of the containers, transfer areas, piping, and other information as required to meet the requirements of §112.7(a)(3).

6.5 Facility Diagram Examples

This section includes example facility diagrams for three fictitious SPCC-regulated facilities. They illustrate how certain containers and equipment could be represented on a facility diagram. Preparation of a facility diagram is a site-specific effort, and the level of detail and/or approach taken to prepare it will vary based on what is needed to adequately describe the configuration for any given facility. The examples provided are not meant to indicate a specific amount of detail an EPA inspector will require for each SPCC-regulated facility. They merely illustrate the concepts discussed in this chapter.

Facility diagrams, like the other elements of an SPCC Plan, must be prepared in accordance with good engineering practice or in accordance with accepted and sound industry practices and standards. They must be reviewed by the PE (or owner/operator, in the case of a Tier II qualified facility) certifying the Plan (§112.3(d) or §112.6(b)). Section 112.7(a)(3) requires the facility diagram to show, at a minimum, the location and contents of fixed oil containers; mobile/portable container storage area locations; completely buried storage tanks, including those that may otherwise be exempt from the rule; and transfer stations (i.e., areas where oil is transferred) and connecting pipes, including exempt intra-facility gathering lines. The facility owner or operator may also include on the diagram additional structures and equipment, and may use the diagram to illustrate other elements that may be relevant to the SPCC Plan and to emergency response. For instance, a diagram may also show the discharge and drainage controls that are described in the SPCC Plan, the predicted flow path for discharged oil based on topography, areas on which to focus inspections, fire-fighting resources, spill response kits or other equipment necessary to implement an active containment measure and/or evacuation routes. The examples presented below are for a bulk storage and distribution facility, a manufacturing facility, and an oil production facility.

6.5.1 Example #1: Bulk Storage and Distribution Facility

Figure 6-3 illustrates a diagram for a bulk storage and distribution facility, which has a tank farm, a loading rack, an unloading area, and other oil containers and oil-filled equipment. This diagram corresponds to the model SPCC Plan for a bulk storage distribution facility that is provided in *Appendix D* of this guidance.

As required by §112.7(a)(3), this diagram includes all containers with an oil storage capacity of 55 gallons or greater. In addition to listing the contents directly on the diagram, the diagram provides a reference to a supplementary table that contains the volume and content of the storage tanks shown on the diagram (appended to the diagram as Table B-1). At the discretion of the Plan preparer who reviewed and certified the Plan, the example facility diagram also depicts secondary containment methods and includes a reference to calculations for secondary containment capacity provided in other parts of the SPCC Plan. Also, a separate log (Table B-2) identifies the contents of the drums in the storage warehouse and estimates the maximum number of containers.

Figure 6-3: Example facility diagram, including a loading rack and a separate loading area.

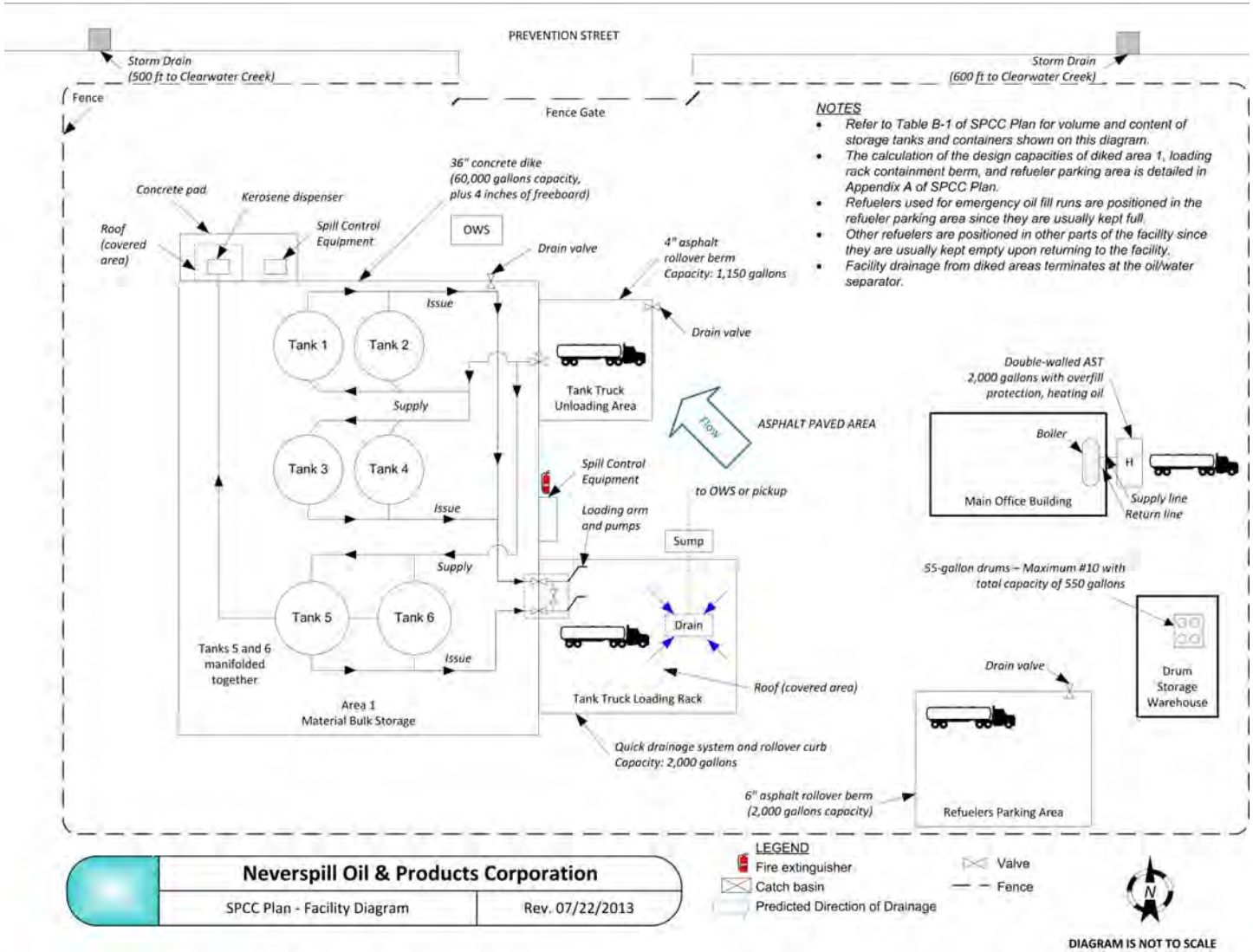


Table B-1: Volume and contents of containers identified on the facility diagram.

Tank/Container	Volume (gallons)	Contents
Area 1		
Tank 1	25,000	Product A – #2 fuel oil
Tank 2	25,000	Product A – #2 fuel oil
Tank 3	25,000	Product B – #6 fuel oil
Tank 4	25,000	Product B – #6 fuel oil
Tank 5	30,000	Product C – Kerosene
Tank 6	30,000	Product C – Kerosene
Main Office Building		
Tank H	2,000	Heating oil
Drum Storage Warehouse		
Up to 10 drums	55 (each)	Various oil products (lubricating oil, engine oil, used oil, etc.)

Rev. 07/22/13

Table B-2: Drum storage warehouse log (maintained at the facility as part of inventory).

Date	Number and Type of Container	Contents	Capacity	Location at facility

6.5.2 Example #2: Manufacturing Facility

Figure 6-4 illustrates a large manufacturing facility with a variety of containers and equipment, including piping, oil-filled equipment (i.e., manufacturing equipment and transformers), and completely buried storage tanks. As required by §112.7(a)(3), this diagram includes all containers with a storage capacity of 55 gallons or greater. In addition to listing the contents directly on the diagram, it includes a reference to a crosswalk that contains the volume and content of the storage containers shown on the diagram (appended to the diagram as Table B-3). While not an SPCC requirement, the diagram also marks the location of containers that store CWA hazardous substances and labels those containers. Additionally, the diagram notes the location and contents of completely buried storage tanks otherwise exempt from the SPCC rule because they meet all the technical requirements of 40 CFR part 280 or an approved state UST program under 40 CFR part 281 (in accordance with the requirements of §112.7(a)(3)).

This diagram also includes an example of how oil-filled manufacturing equipment and complex piping may be represented on a facility diagram, at the discretion of the owner/operator or PE. The diagram references the more detailed diagrams and plans of the piping and manufacturing equipment that are available separately at the facility.

Finally, while not required in the diagram, this example also includes a reference to the calculation of diked storage provided in other parts of the SPCC Plan and depicts wastewater treatment systems, secondary containment, and oil/water separators.

Figure 6-4: Example facility diagram, including oil-filled equipment, complex piping, and completely buried storage tanks.

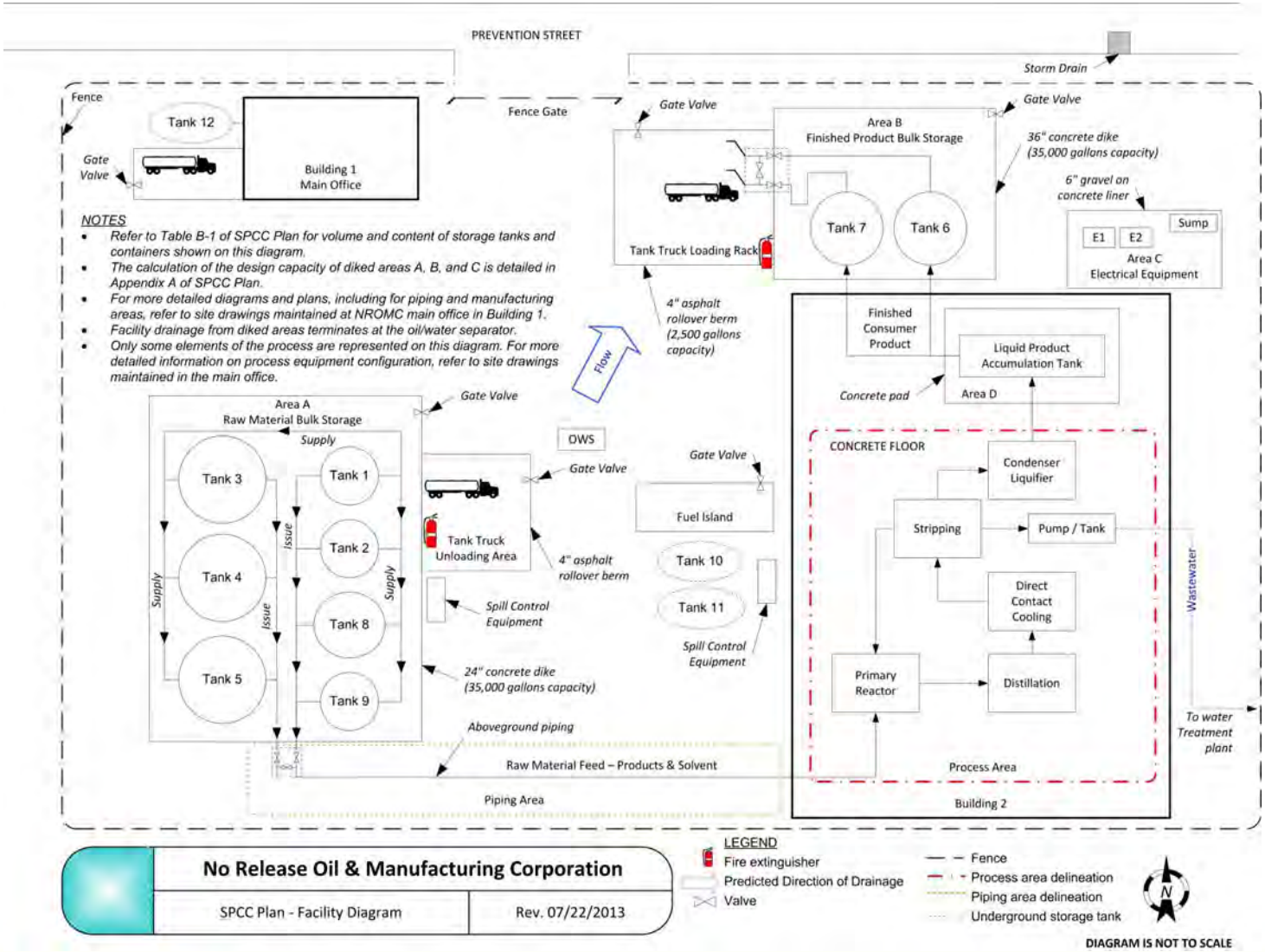


Table B-3: Volume and contents of containers identified on the facility diagram.

Tank/Container	Volume (gallons)	Contents
Area A – Raw Material Bulk Storage		
Tank 1	4,000	Product A – #2 fuel oil
Tank 2	4,000	Product A – #2 fuel oil
Tank 3	20,000	Product B – #6 fuel oil
Tank 4	20,000	Product B – #6 fuel oil
Tank 5	20,000	Product B – #6 fuel oil
Tank 8	6,000	Product C – Kerosene
Tank 9	4,000	Solvent – Toluene
Area B – Finished Product Bulk Storage		
Tank 6	20,000	Product D – proprietary oil
Tank 7	20,000	Product D – proprietary oil
Area C – Electrical Equipment		
Transformer E1	235	Silicon-based dielectric fluid
Transformer E2	235	Silicon-based dielectric fluid
Area D		
Liquid Product Accumulation Tank	10,000	Product D – proprietary oil
Process Area		
Primary Reactor	500	intermediate oil product
Distillation	500	intermediate oil product
Direct Contact Cooling	500	intermediate oil product
Stripping	500	intermediate oil product
Pump/Tank	300	intermediate oil product
Condenser Liquefier	500	intermediate oil product
Underground Storage Tanks		
Tank 10 (otherwise exempt from SPCC requirements)	8,000	gasoline
Tank 11 (otherwise exempt from SPCC requirements)	8,000	gasoline
Tank 12	2,000	heating oil

Rev. 07/22/13

6.5.3 Example #3: Oil Production Facility

Figure 6-5 illustrates a small oil production facility with two extraction wells and a production tank battery. As required by §112.7(a)(3), this diagram includes all containers with a storage capacity of 55 gallons or

greater and transfer areas. Because the facility has a relatively large footprint, the direction of flow is best displayed on a separate figure that shows the general location of the site relative to receiving water bodies ().

Figure 6-5: Example facility diagram for an oil production facility.

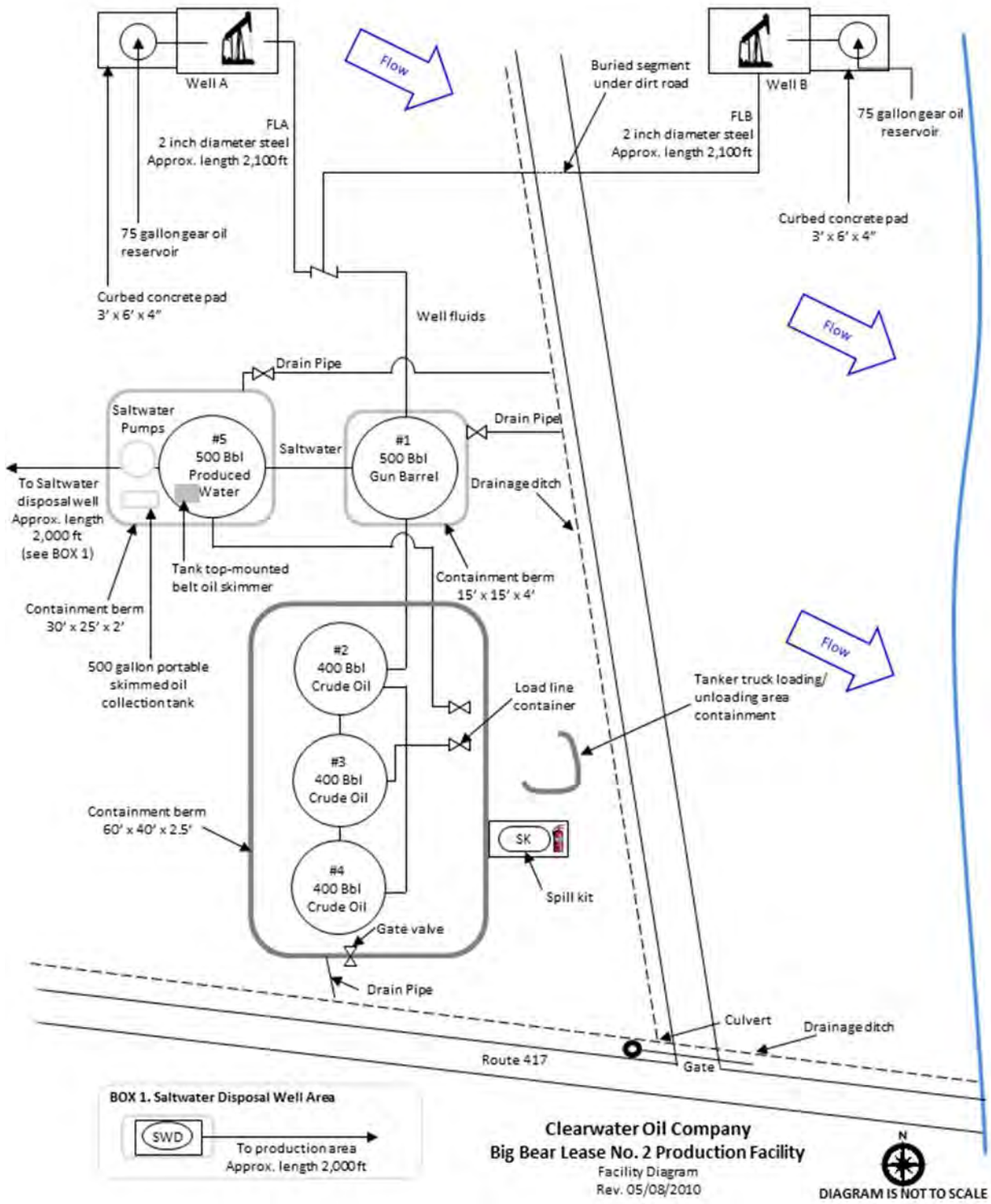
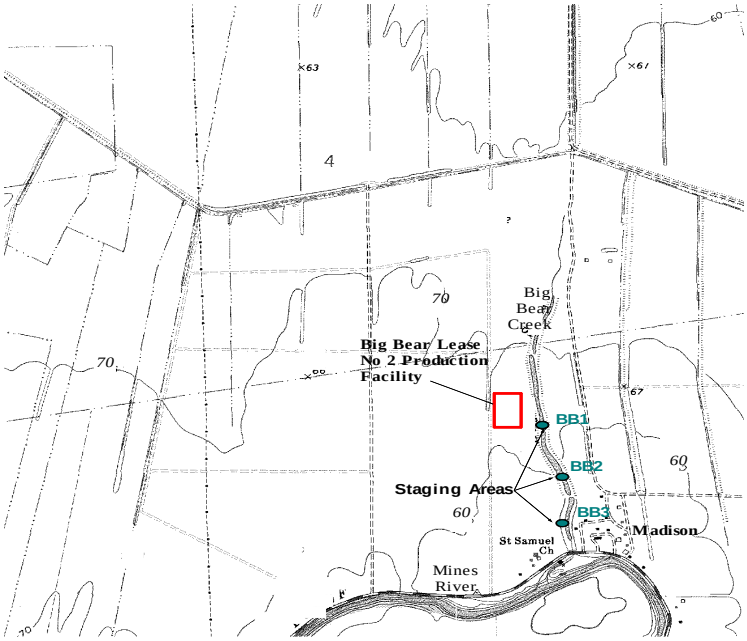


Figure 6-6: Example general facility location diagram for an oil production facility.



6.6 Review of a Facility Diagram

6.6.1 Documentation by Owner/Operator

The person certifying the SPCC Plan attests familiarity with the requirements of 40 CFR part 112; that the Plan has been prepared in accordance with good engineering practice (or for a Tier II qualified facility, in accordance with accepted and sound industry practices and standards); follows the requirements of 40 CFR part 112; and that the Plan is adequate for the facility. Thus, if an SPCC Plan is certified, and the facility diagram is consistent with the rule requirements, it will most likely be considered acceptable by regional EPA inspectors. However, if the facility design has changed and is no longer accurately represented on the diagram, the supporting drawings for a simplified diagram are not available at the facility, or the diagram appears to be

inadequate for the facility, appropriate follow-up action may be warranted. This action may include a request for more information or a Plan amendment in accordance with §112.4(d).

Additionally, changes to the facility diagram are considered administrative in nature and do not require PE certification. (72 FR 58389, October 15, 2007) The same is true for a Tier II qualified facility: the owner or operator does not need to certify changes to a facility diagram in accordance with §112.6(b)(2) because these changes are not considered technical amendments.

6.6.2 Role of the EPA Inspector

As part of the EPA inspection, the inspector will verify that the diagram accurately represents the facility layout and provides sufficient detail as outlined in §112.7(a)(3), and use it as a guide for the containers and piping inspected during the site visit.

The EPA inspector should verify that the diagram included in the Plan includes:

- Location and contents of each fixed container (except those below the *de minimis* container size of 55 gallons as described in *Section 6.4.3*, above).
- Location of storage areas (which may also include operational or staging areas) for mobile or portable containers.
- Completely buried tanks, including those that are otherwise exempt from the SPCC rule by §112.1(d)(4).
- All transfer stations (i.e., areas where oil is transferred) and connecting pipes including intra-facility gathering lines that are otherwise exempt from the SPCC rule by §112.1(d)(11).

Although EPA stated in both the preamble of the 2002 SPCC rule (67 FR 47097, July 17, 2002) and in §112.7(a)(3) that <u>all</u> facility transfer stations and connecting pipes that handle oil must be included in the diagram, the rule allows flexibility on the method of depicting concentrated areas of piping and oil-filled manufacturing equipment on the facility diagram. These areas may be represented in a more simplified manner, as long as more detailed diagrams (such as blueprints, engineering diagrams, or process charts) are available at the facility and referenced in the SPCC Plan. The EPA inspector may ask to review more detailed diagrams of piping and oil-filled manufacturing equipment if further information is needed during a site inspection

Chapter 7 Inspection, Evaluation, and Testing

7.1 Introduction

The inspection, evaluation and testing requirements of the SPCC rule are intended to prevent, predict and detect potential integrity or structural issues before they cause a leak, spill or discharge of oil to navigable waters or adjoining shorelines. Regularly scheduled inspections, evaluations, and testing by qualified personnel are critical parts of oil discharge prevention. They are conducted not only on containers, but also on associated piping, valves, and appurtenances, and on other equipment and components that could be a source or cause of an oil discharge.

Activities may involve one or more of the following: an external visual **inspection** of containers, piping, valves, appurtenances, foundations, and supports; a non-destructive **testing** (examination) to evaluate integrity of certain containers; and additional **evaluations**, as needed, to assess the equipment's fitness for continued service. The type of inspection program and its scope will depend on site-specific conditions and the application of good engineering practices, adherence to applicable industry standards and/or manufacturer's requirements. An inspection, evaluation, and testing program that complies with SPCC requirements should specify the procedures, schedule/frequency, types of equipment covered, person(s) conducting the activities, recordkeeping practices, and other elements as outlined in this chapter.

The remainder of this chapter is organized as follows:

- ***Section 7.2*** provides an overview of the SPCC inspection, evaluation, and testing requirements.
- ***Section 7.3*** discusses the role of industry standards and recommended practices in meeting SPCC requirements.
- ***Section 7.4*** discusses determining a baseline in order to establish a regular inspection schedule.
- ***Section 7.5*** presents special circumstances, including the use of environmentally equivalent measures. This section also includes suggested minimum requirements for a hybrid inspection program.
- ***Section 7.6*** discusses the role of the EPA inspector in reviewing a facility's compliance with the rule's inspection, evaluation, and testing requirements.
- ***Section 7.7*** summarizes industry standards, code requirements, and recommended practices (RPs) that apply to different types of equipment.

7.2 Inspection, Evaluation, and Testing under the SPCC Rule

Various provisions of the SPCC rule relate to the inspection, evaluation, and testing of containers, associated piping, and other oil-containing equipment. Different requirements apply to different types of equipment, oil, and facilities. The requirements are generally aimed at preventing discharges of oil caused by leaks, corrosion, brittle fracture, overfill, or other forms of container or equipment failure by ensuring that containers used to store oil have the necessary physical integrity for continued oil storage. The requirements are also aimed at detecting container and equipment failures (such as pinhole leaks) before they can become significant and result in a discharge as described in §112.1(b).

7.2.1 Summary of Inspection, Evaluation and Integrity Testing Requirements

Table 7-1 summarizes the provisions that apply to different types of equipment and facilities. As shown in the table, applicable inspection and testing provisions vary depending on the type of equipment, facility, and circumstances. For example, some inspection and testing provisions apply specifically to bulk storage containers at onshore facilities (other than oil production facilities) while other inspection and/or testing requirements apply to other components of a facility that might cause a discharge (such as vehicle drains, foundations, or other equipment or devices). Animal fat and vegetable oil (AFVO) containers that meet certain criteria are eligible for differentiated integrity testing requirements. Onshore oil production facilities have a distinct set of inspection requirements including minimum expectations for a flowline maintenance program. The SPCC rule also includes regulatory alternatives to sized secondary containment that include inspection and corrective action requirements.

Finally, additional requirements apply under certain circumstances, such as when an aboveground field-constructed container undergoes repairs, alterations, or a change in service that may affect its potential for a brittle fracture or other catastrophic failure, or in cases where secondary containment for bulk storage containers is impracticable (§112.7(d), as described in *Chapter 4: Secondary Containment and Impracticability*). Facility owners and operators must maintain records to demonstrate compliance with the inspection, evaluation, and integrity testing requirements per §112.7(e).

Table 7-1: Summary of SPCC inspection, evaluation, and integrity testing program provisions and associated recordkeeping requirements.

Facility Component	Section(s)	Action	Method, Circumstance, and Required Action
(Text in italics indicates the frequency or circumstances for performing the activity, as specified in the SPCC rule.)			
General Requirements Applicable to All Facilities			
Bulk storage containers with no secondary containment and for which an impracticability determination has been made	112.7(d)	**Test**	Integrity testing. *Periodically.* Integrity testing is required for all bulk storage containers. In cases where no secondary containment is present because it is impracticable, good engineering practice may suggest more frequent testing than would otherwise be scheduled. Note that this includes bulk storage containers at oil production, drilling and workover facilities that are not typically subject to integrity testing requirements.
Valves and piping associated with bulk storage containers with no secondary containment and for which an impracticability determination has been made	112.7(d)	**Test**	Integrity and leak testing of valves and piping associated with containers that have no secondary containment as described in §112.7(c). *Periodically.*
Recordkeeping requirement	112.7(e)	**Record**	Keep written procedures and a signed record of inspections[106] and tests for a period of three years.[107] Records kept under usual and customary business practices will suffice. *For all actions.*
Lowermost **drain** and all **outlets** of tank car or tank truck at loading/unloading racks	112.7(h)(3)	**Inspect**	Visually inspect. *Prior to filling and departure of tank car or tank truck from loading/unloading racks.*

[106] Inspections include evaluations (e.g. brittle fracture evaluation) required under the regulation.

[107] Certain industry standards require recordkeeping beyond three years. Facility owners/operators should keep comparison records of integrity inspections and tests as directed in the standard, but no less than three years in accordance with the SPCC record retention requirement, in order to identify changing conditions of the oil storage container. EPA recommends that formal testing and inspection records or reports be retained for the life of the container.

Facility Component	Section(s)	Action	Method, Circumstance, and Required Action
Field-constructed **aboveground container**	112.7(i)	**Evaluate** **Corrective Action**	Evaluate potential for brittle fracture or other catastrophic failure. *When the container undergoes a repair, alteration, reconstruction or a change in service that might affect the risk of a discharge or failure due to brittle fracture or other catastrophe, or has discharged oil or failed due to brittle fracture failure or other catastrophic failure*. Based on the results of this evaluation, take appropriate action.
Onshore Facilities (Excluding Oil Production Facilities)[108]			
Diked areas	112.8(b)(1) & 112.8(b)(2) or 112.12(b)(1) & 112.12(b)(2)[109]	**Inspect** **Record**	Visually inspect content for presence of oil when draining into a watercourse. *Prior to draining.* Keep adequate records of such events.
Diked areas for bulk storage containers	112.8(c)(3) & 112.8(c)(3)	**Inspect** **Record**	Inspect retained rainwater to ensure that it will not cause a discharge as described in §112.1(b) when draining to storm sewer or open watercourse, lake or pond. *Prior to draining.* Keep adequate records of such events.
Buried *metallic* storage tank installed on or after January 10, 1974	112.8(c)(4) or 112.12(c)(4)	**Test**	Leak test. *Regularly*
Aboveground **bulk storage container**	112.8(c)(6) or 112.12(c)(6)	**Test or Inspect**	Test or inspect each container for integrity. *Following a regular schedule and whenever material repairs are made.* Determine scope, frequency of testing and qualification of personnel performing the test or inspection, in accordance with industry standards. Tests include, but are not limited to, visual inspection, hydrostatic testing or other non-destructive testing.
Aboveground **bulk storage container**	112.8(c)(6) or 112.12(c)(6)	**Inspect**	Inspect outside of container for signs of deterioration and discharges. *Frequently.*
Aboveground bulk storage container **supports and foundations**	112.8(c)(6) or 112.12(c)(6)	**Inspect**	Inspect container's supports and foundations. *Following a regular schedule and whenever material repairs are made.*

108 Note that §112.8 provisions apply to facilities that store petroleum oils and non-petroleum oils (excluding AFVO). §112.12 provisions apply to facilities storing AFVO (i.e., animal fats and oils and greases, and fish and marine mammal oils; and for vegetable oils, including oils from seeds, nuts, fruits, and kernels.) Also see alternative provisions in table under "Onshore Facilities (Excluding Production) – Animal Fats and Vegetable Oils."

109 Sections 112.8(b)(2) and 112.12(b)(2) reference dike drainage procedures in §§112.8(c)(3)(ii)-(iv) and 112.12(c)(3)(ii)-(iv). These dike drainage procedures apply to any facility drainage that drains directly to a watercourse.

Facility Component	Section(s)	Action	Method, Circumstance, and Required Action
Diked areas around bulk containers	112.8(c)(6) or 112.12(c)(6)	**Inspect**	Inspect for signs of deterioration, discharges, or accumulation of oil inside diked areas. *Frequently*.
Steam return and exhaust lines	112.8(c)(7) or 112.12(c)(7)	**Monitor**	Monitor for leaks from defective internal heating coils. *On an ongoing or regular basis*.
Liquid level sensing devices	112.8(c)(8)(v) or 112.12(c)(8)(v)	**Test**	Test for proper operation. *Regularly.*
Effluent treatment facilities	112.8(c)(9) or 112.12(c)(9)	**Observe**	Detect possible system upsets that could cause a discharge. *Frequently.*
Bulk storage containers	112.8(c)(10) or 112.12(c)(10)	**Corrective Action**	Correct visible discharges which result in a loss of oil from the container, including but not limited to seams, gaskets, piping, pumps, valves, rivets, and bolts. Remove any accumulations of oil in diked areas. *Promptly.*[110]
Buried piping[111]	112.8(d)(1) or 112.12(d)(1)	**Inspect** **Corrective Action**	Inspect for deterioration. *Whenever a section of buried line is exposed for any reason.* If corrosion damage is found, additional examination and corrective action must be undertaken as indicated by the magnitude of the damage.
	112.8(d)(4) or 112.12(d)(4)	**Test**	Integrity and leak testing. *At the time of installation, modification, construction, relocation, or replacement.*
All aboveground **valves, piping, and appurtenances**	112.8(d)(4) or 112.12(d)(4)	**Inspect**	During the inspection, assess general condition of items, such as flange joints, expansion joints, valve glands and bodies, catch pans, pipeline supports, locking of valves, and metal surfaces. *Regularly.*
Onshore Oil Production Facilities (Excluding Drilling and Workover Facilities)			
Diked areas associated with tank batteries and separation and treating areas	112.9(b)(1)	**Inspect** **Corrective Action**	Visually inspect contents of dike area and take action in accordance with §112.8(c)(3)(ii), (iii), and (iv). *Prior to draining.* Remove accumulated oil on the rainwater and return it to storage or dispose of it in accordance with legally approved methods. *Prior to draining.*

110 "Prompt'' removal means beginning the cleanup of any accumulation of oil immediately after discovery of the discharge, or immediately after any actions to prevent fire or explosion or other threats to worker health and safety, but such actions may not be used to unreasonably delay such efforts (67 FR 47122, July 17, 2002).

111 Any buried piping connected to an exempt completely buried storage tank regulated under 40 CFR part 280 or 281 is also exempt from the SPCC rule.

Facility Component	Section(s)	Action	Method, Circumstance, and Required Action
Field **drainage systems** (such as drainage ditches or road ditches), **oil traps, sumps, and skimmers**	112.9(b)(2)	**Inspect** **Corrective Action**	Inspect for an accumulation of oil that may have resulted from any small discharge. *Inspect at regularly scheduled intervals.* Remove any accumulations of oil. *Promptly.*
Aboveground bulk storage containers	112.9(c)(3)	**Inspect**	Visually inspect each container to assess deterioration and maintenance needs. *Periodically and on a regular schedule.*
Foundation and support of each aboveground container that is on or above the surface of the ground	112.9(c)(3)	**Inspect**	Visually inspect to assess deterioration and maintenance needs. *Periodically and on a regular schedule.*
Flow-through process vessels and associated components (such as dump valves) without sized secondary containment	112.9(c)(5)(i)	**Inspect and/or test**	Visually inspect and/or test for leaks, corrosion, or other conditions that could lead to a discharge as described in 112.1(b). *Periodically and on a regular schedule.*
Flow-through process vessels and associated components without sized secondary containment	112.9(c)(5)(ii)	**Corrective Action**	Take corrective action or make repairs. *As indicated by regularly scheduled visual inspections, tests, or evidence of an oil discharge.*
Flow-through process vessels without sized secondary containment	112.9(c)(5)(iii)	**Corrective Action**	Remove or initiate actions to stabilize and remediate any accumulations of oil discharges associated with flow-through process vessels. *Promptly.*
Produced water containers without sized secondary containment	112.9(c)(6)(i)	***Implement Procedure*** **Record**	Implement a procedure for each produced water container that is designed to separate the free-phase oil that accumulates on the surface of the produced water. *On a regular schedule.* Include in the Plan a description of the procedures, frequency, amount of free-phase oil expected to be maintained inside the container, and a Professional Engineer (PE) certification in accordance with §112.3(d)(1)(vi). Maintain records of such events in accordance with §112.7(e).

Facility Component	Section(s)	Action	Method, Circumstance, and Required Action
Produced water containers and associated piping without sized secondary containment	112.9(c)(6)(ii)	**Inspect and/or test**	Visually inspect and/or test for leaks, corrosion, or other conditions that could lead to a discharge as described in 112.1(b) in accordance with good engineering practice. *On a regular schedule.*
Produced water containers and associated piping without sized secondary containment	112.9(c)(6)(iii)	**Corrective action**	Take corrective action or make repairs. As indicated by regularly scheduled visual inspections, tests, or evidence of an oil discharge.
Produced water containers and associated piping without sized secondary containment	112.9(c)(6)(iv)	**Corrective action**	Remove or initiate actions to stabilize and remediate any accumulations of oil discharges. *Promptly*.
All aboveground **valves and piping** associated with transfer operations	112.9(d)(1)	**Inspect**	Inspect for the general condition of flange joints, valve glands and bodies, drip pans, pipe supports, pumping well polish rod stuffing boxes, bleeder and gauge valves, and other such items. *Periodically and upon a regular schedule.*
Saltwater (oil field brine) disposal facilities	112.9(d)(2)	**Inspect**	Inspect to detect possible system upsets capable of causing a discharge. *Often, particularly following a sudden change in atmospheric temperature.*
Flowlines and intra-facility gathering lines and associated appurtenances	112.9(d)(4)(ii)	**Inspect and/or test**	Visually inspect and/or test for leaks, oil discharges, corrosion, or other conditions that could lead to a discharge as described in 112.1(b). *On a periodic and regular schedule*. For flowlines and intra-facility gathering lines that are not provided with secondary containment in accordance with §112.7(c), inspect or test the lines such that the *frequency and type of testing allows for the implementation of a contingency plan as described under 40 CFR part 109.*
Flowlines and intra-facility gathering lines and associated appurtenances	112.9(d)(4)(iii)	**Corrective Action**	Take corrective action or make repairs. As indicated by regularly scheduled visual inspections, tests, or evidence of a discharge.
Flowlines and intra-facility gathering lines and associated appurtenances	112.9(d)(4)(iv)	**Corrective Action**	Remove or initiate actions to stabilize and remediate any accumulations of oil discharges. *Promptly.*

Facility Component	Section(s)	Action	Method, Circumstance, and Required Action
Offshore Oil Drilling, Production, and Workover Facilities			
Oil drainage collection equipment, where drains or sumps are not practicable	112.11(b)	**Corrective action**	Remove oil contained in collection equipment *as often as necessary to prevent overflow.*
Sump system (liquid removal system and pump start-up device)	112.11(c)	**Inspect and Test**	Use preventive maintenance, inspection and testing program to assure reliable operation. *Regularly scheduled.*
Pollution prevention equipment and systems	112.11(h) & (i)	**Inspect and Test**	Prepare and maintain a written procedure within the Plan for inspecting and testing pollution prevention equipment and systems. Conduct testing and inspection of the pollution prevention equipment and systems commensurate with the complexity, conditions, and circumstances of the facility and any other appropriate regulations. Use simulated discharges for testing and inspecting human and equipment pollution control and countermeasure systems. *On a scheduled periodic basis.*
Sub-marine piping	112.11(p)	**Inspect and Test**	Inspect and test for good operating conditions and for failures. *Periodically and according to a schedule.*
Onshore Facilities (Excluding Oil Production) – Animal Fats and Vegetable Oils[112]			
Bulk storage containers that are subject to 21 CFR part 110, are elevated, constructed of austenitic stainless steel, have no external insulation and are shop-fabricated; **and associated diked areas**	112.12(c)(6)(ii)	**Inspect**	Conduct formal visual inspection of bulk storage containers. *Following a regular schedule.* Inspect the outside of the container for signs of deterioration, discharges, or accumulation of oil inside diked areas. *Frequently*.

The SPCC rule is a performance-based regulation. Since each facility may present unique characteristics and methods may evolve as new technologies are developed, the rule does not prescribe a specific frequency or method to perform the required inspections, evaluations, and tests. Instead, it relies on the use of good

[112] Note that additional inspection requirements applicable to AFVO facilities are described in the table above. See alternative provisions in table under "Onshore Facilities (Excluding Production Facilities)."

engineering practice, based on the professional judgment of the PE (for a PE-certified SPCC Plan), which includes consideration of applicable industry standards. In addition, recommended practices, safety considerations, and requirements of other federal, state, or local regulations may be considered in the development and certification of the SPCC Plan. Section 112.3(d)(1) specifically states that the PE certifying a Plan attests that "procedures for required inspections and testing have been established." Section 112.3(d)(1) also states that the Plan must be prepared in accordance with good engineering practice, including consideration of applicable industry standards, and with the requirements of 40 CFR part 112. Thus, when certifying an SPCC Plan, a PE is also certifying that the inspection program described in the Plan is appropriate for the facility and is consistent with good engineering practice.

Similarly, the owner/operator of a qualified facility[113] who self-certifies the SPCC Plan must attest that the SPCC Plan has been prepared in accordance with the SPCC rule[114] and accepted and sound industry practices and standards; that procedures for inspections and tests have been established for the facility; and that the Plan will be implemented. While owners and operators of qualified facilities may choose not to have their SPCC Plans certified by a PE, they are still required to comply with all of the SPCC requirements and to develop and implement a spill prevention program in accordance with good engineering practices, and may do so by following regulatory guidance and industry recommended practices, consulting with tank testing professionals, and implementing standard design and operation protocols.

The preamble to the 2002 SPCC rule amendment (67 FR 47042, July 17, 2002) lists examples of industry standards and recommended practices that may be relevant to determining what constitutes good engineering practice for various rule provisions. These industry standards are summarized in *Table 7-2* and *Table 7-3* (*Section 7.3*) and further discussed in *Section 7.7*. Although EPA refers to the use of industry standards to determine inspection and integrity testing practices, the Agency does not prescribe a particular standard or schedule for testing. "Good engineering practice" and relevant industry standards change over time. In addition, site-specific conditions at an SPCC-regulated facility play a significant role in the development of appropriate inspections and tests and the associated schedule for these activities. For example, the American Petroleum Institute (API) Standard 653, "Tank Inspection, Repair, Alteration, and Reconstruction," includes a cap on the maximum time interval between inspections, and provides specific criteria for alternative inspection intervals based on the calculated corrosion rate or risk-based inspection assessment. API 653 also provides an internal inspection interval when the corrosion rates are not known. Similarly, the Steel Tank Institute (STI) Standard SP001 provides specific intervals for external inspection of portable containers; and external and internal inspection of shop-built containers and small field-erected containers based on container size and configuration. Site-specific

---

113 The self-certification option is designed for owners and operators of those facilities that store smaller amounts of oil. These smaller amounts of oil generally translate to facilities with simpler, pre-engineered installations, such as restaurants, office buildings, family farms, automotive repair shops, and rural electrical substations. For more information on qualified facilities, see *Chapter 1: Introduction.*

114 Note that this provision applies to Tier II qualified facility Plans. The Tier I qualified facility self-certification provisions in §112.6(a)(1) do not require the owner or operator to attest that the Plan was prepared in accordance with the SPCC rule because the template in Appendix G of the rule, that serves as the SPCC Plan for these facilities, addresses applicable rule requirements.

conditions may therefore affect the exact schedule of inspections and tests conducted under either industry standard.

Finally, environmentally equivalent measures may substitute for integrity testing requirements as allowed under §112.7(a)(2) when reviewed and certified by a PE.[115] *Chapter 3: Environmental Equivalence* provides a general discussion of environmental equivalence, while *Section 7.5* discusses its particular relevance to bulk storage container integrity testing and inspection requirements at onshore facilities and other special circumstances.

> **FYI – Oil-filled equipment**
>
> Oil-filled equipment is not a bulk storage container and, therefore, NOT subject to the integrity testing requirements of the SPCC rule.

The remaining portions of *Section 7.2* discuss various requirements related to the inspection, testing, evaluation, and maintenance of selected components of facilities (*Sections 7.2.1* through *7.2.13*). The section ends with a discussion of the general role of industry standards in meeting SPCC requirements (*Section 7.3*).

7.2.2 Regularly Scheduled Integrity Testing and Inspection of Aboveground Bulk Storage Containers (at Onshore Facilities Other than Oil Production Facilities)

Section 112.8(c)(6) of the SPCC rule specifies the inspection and testing requirements for aboveground bulk storage containers at onshore facilities that store petroleum oils and non-petroleum oils (except AFVOs). Section 112.12(c)(6) contains similar requirements for facilities with animal fats and vegetable oils.[116] The SPCC rule has two distinct inspection requirements for bulk storage containers:

- Test or inspect **each** container for integrity on a regular schedule and whenever material repairs are made; and
- Frequently inspect the outside of the container for signs of deterioration, discharges, or accumulation of oil inside diked areas. This visual inspection is intended to be a routine walk-around and includes the container's supports and foundations.

[115] Qualified facility owners or operators who choose to self-certify their SPCC Plan, as allowed under §112.3(g), may incorporate environmentally equivalent alternatives in the Plan when each alternate method is reviewed and certified in writing by a PE.

[116] See *Section 7.5.2* for more information on deviating from the SPCC rule requirements based on environmental equivalence.

§112.8(c)(6)

Test or inspect each aboveground container for integrity on a regular schedule and whenever you make material repairs. You must determine, in accordance with industry standards, the appropriate qualifications for personnel performing tests and inspections, the frequency and type of testing and inspections, which take into account container size, configuration, and design (such as containers that are: shop-built, field-erected, skid-mounted, elevated, equipped with a liner, double-walled, or partially buried). Examples of these integrity tests include, but are not limited to: visual inspection, hydrostatic testing, radiographic testing, ultrasonic testing, acoustic emissions testing, or other systems of non-destructive testing. You must keep comparison records and you must also inspect the container's supports and foundations. In addition, you must frequently inspect the outside of the container for signs of deterioration, discharges, or accumulation of oil inside diked areas. Records of inspections and tests kept under usual and customary business practices satisfy the recordkeeping requirements of this paragraph.

Note: The above text is only a brief excerpt of the rule. Refer to 40 CFR part 112 for the full text of the rule.

Integrity testing is any means to measure the strength (structural soundness) of a container shell, bottom, and/or floor to contain oil, and may include leak testing to determine whether the container will discharge oil (67 FR 47120, July 17, 2002). The integrity testing and routine inspection requirements apply to aboveground bulk storage containers with a capacity of 55 gallons[117] or more, including:

- Large (field-constructed or field-erected) and small (shop-built) aboveground containers; [118]
- Containers located on, partially in (partially buried, bunkered, or vaulted tanks), and off the ground wherever located; and
- Double-walled containers.

Regularly scheduled integrity tests or inspections

Integrity testing is a necessary component of any good oil discharge prevention plan. Integrity testing is necessary to determine whether the bulk storage container (e.g., tank) is suitable for continued use until the next formal inspection. It will help to prevent discharges by testing the integrity of containers, ensuring they are suitable for continued service under current and anticipated operating conditions (e.g., product, temperature, pressure). For example, testing may help facility owners/operators to determine whether corrosion has reached a point where repairs are required or replacement of the container is necessary. Information obtained through

[117] For information on inspecting mobile/portable containers, see *Section 7.5.1*.

[118] STI SP001 makes the distinction between field-erected and shop-fabricated tanks. A field-erected aboveground storage tank (AST) is a welded metal AST erected on the site where it will be used. For the purpose of the standard, ASTs are to be inspected as field-erected ASTs if they are either: (a) an AST where the nameplate indicates that it is a field-erected AST, and limited to a maximum shell height of 50 feet and maximum diameter of 30 feet; or (b) an AST without a nameplate that is more than 50,000 gallons and has a maximum shell height of 50 feet and a maximum diameter of 30 feet. A shop-fabricated AST is a welded metal AST fabricated in a manufacturing facility or an AST not otherwise identified as field-erected with a volume less than or equal to 50,000 gallons. (STI SP001, "Standard for the Inspection of Aboveground Storage Tanks," 5th Edition September 2011)

integrity testing also enables a facility owner/operator to budget and plan for routine maintenance and any associated repairs and avoid unexpected disruptions to facility operations.

Industry standards describe procedures to identify the condition of the container through formal internal and external inspections conducted by certified personnel. For internal inspections, the container must typically be taken out of service, cleaned, and made ready for personnel to enter the container.

Examples of integrity tests include, but are not limited to:

- Visual inspection,
- Radiographic examination,
- Ultrasonic Testing (UT), including Ultrasonic Thickness Scan (UTS) and Ultrasonic Thickness Testing (UTT),
- Magnetic Flux Leakage (MFL) scan,
- Helium leak testing,
- Magnetic particle examination,
- Liquid penetrant examination,
- Acoustic emissions testing,
- Hydrostatic testing,
- Inert gas leak testing, or
- Other methods of non-destructive examination.

FYI – Industry standard identified in SPCC Plan

The industry standard identified in an SPCC Plan outlines the specific inspection and integrity testing protocol for the containers at the facility. These protocols may vary depending on the size and configuration of the facility's containers.

For example, portable containers (e.g., a drum) have fewer inspection requirements than shop-built and field-erected containers.

Acoustic emissions testing and UT robotic measurement[119] are non-destructive examination methods that can be used while the tank is in service. Acoustic emissions testing is used to determine if there is a leak but does not determine if there is corrosion or metal loss. Hydrostatic testing is typically performed on new tanks and on existing tanks that have had major repairs or alterations. Industry standards may use one, or a

[119] The PE should determine how to incorporate robotic inspections into an integrity testing program. Robotic inspections alone may not constitute a comprehensive integrity testing evaluation of the container as specified by the appropriate industry standards.

combination, of these non-destructive examination methods or tests as part of an integrity testing program.[120] If there are containers at the facility that have never been inspected for integrity, then, depending on their size and configuration, industry standards may require that the owner or operator first assess baseline conditions for these containers in order to develop an inspection and testing protocol (see *Section 7.4* of this chapter for information on determining a baseline).

According to §112.8(c)(6), the frequency and type of testing and inspections as well as the qualifications for personnel performing tests and inspections must be determined in accordance with applicable industry standards. While frequent external visual inspections can often be completed by trained facility personnel, the requirement to conduct regular integrity tests or inspections may involve hiring specialized personnel (as specified by the applicable industry standard). For example, integrity testing of field-erected aboveground storage tanks in accordance with API 653 involves formal in-service external inspections and formal out-of-service internal inspections conducted by an API 653 certified inspector. A formal in-service external inspection involves visual inspection (typically using a standard checklist) and UT measurements of the tank shell. A formal out-of-service internal inspection determines the condition of the tank's floor, welds, walls and structure, but should also include the shell, roof (fixed or floating roof), nozzles, and tank appurtenances. The out-of-service inspection typically includes non-destructive testing such as MFL scanning of the floor, vacuum box testing of floor welds, helium leak testing, UT measurements, and tank bottom settlement measurements.

Integrity Testing and Secondary Containment Impracticability

Periodic integrity testing is required as an additional measure in §112.7(d) when it is impracticable to provide adequate secondary containment for bulk storage containers (among other measures). The Plan preparer may decide, based on good engineering practice, to increase the frequency of integrity tests for containers that have inadequate secondary containment because there is a higher potential of a discharge reaching navigable waters or adjoining shorelines.

This approach to establish an increased inspection frequency for an aboveground container without secondary containment is used in the STI SP001 standard.

The SPCC rule requires that integrity testing of aboveground bulk storage containers be performed on a regular schedule, as well as when material repairs[121] are made, because such repairs might increase the potential for oil discharges. Testing on a 'regular schedule' means testing per industry standards or at a frequency sufficient to prevent discharges. (67 FR 47119, July 17, 2002).

Industry standards establish the scope and frequency for inspections, considering the particular conditions of the aboveground container. These conditions may include the age, service history, original construction specifications (e.g., shop-built vs. field-erected, welded steel vs. riveted steel), prior inspection results, and the existing condition of the container. They may also consider the degree of risk of a discharge to

120 Note that in some circumstances, industry standards allow visual inspection alone for portable containers.

121 Examples of material repairs include removal or replacement of the annular plate ring; replacement of the container bottom; jacking of a container shell; installation of a 12-inch or larger nozzle in the shell; replacement of a door sheet or tombstone in the shell, or other shell repair; or such repairs that might materially change the potential for oil to be discharged from the container.

navigable waters and adjoining shorelines. For example, for containers that are located near saltwater, an accelerated corrosion rate would be expected. The frequency of inspections is based on the changing conditions of the container (e.g., corrosion rates, settling); the interval between inspections may therefore vary over the lifetime of the container.

Once the Plan preparer selects an inspection schedule for aboveground containers (based on applicable industry standards), it must be documented in the SPCC Plan and the owner or operator must conduct inspections according to that schedule. The Plan should also include a description of the conditions of the container at the time the Plan was certified that led to the specific inspection schedule identified.

Frequent Inspections – Visual

The rule requires frequent inspections of the outside of the container for signs of deterioration, discharges, or accumulations of oil inside diked areas (§112.8(c)(6)). This visual inspection is intended to be a routine walk-around and include the container's supports and foundations. The scope and frequency of the inspection is determined by industry standards or according to a site-specific inspection program developed and certified[122] by the Plan preparer. Industry standards typically require monthly visual inspections, although some facilities conduct daily or weekly visual inspections of their containers. EPA expects the visual inspection to occur on an ongoing routine basis, to be conducted by qualified personnel, and to follow industry standards. The necessary qualifications for personnel conducting the inspections are outlined in tank inspection standards such as API 653 and STI SP001. Records of visual inspections should be maintained and kept under usual and customary business practices.

7.2.3 Removal of Oil Accumulations in Bulk Storage Container Diked Areas

The rule requires that the owner or operator promptly correct visible discharges which result in a loss of oil from a bulk storage container, including but not limited to seams, gaskets, piping, pumps, valves, rivets, and bolts and remove oil accumulations in diked areas. "Prompt'' removal means beginning the cleanup of any accumulation of oil immediately after discovery of the discharge, or immediately after any actions to prevent fire or explosion or other threats to worker health and safety, but such actions may not be used to unreasonably delay such efforts (67 FR 47122, July 17, 2002).

§112.8(c)(10) and §112.12(c)(10)

Promptly correct visible discharges which result in a loss of oil from the container, including but not limited to seams, gaskets, piping, pumps, valves, rivets, and bolts. You must promptly remove any accumulations of oil in diked areas.

Note: The above text is only a brief excerpt of the rule. Refer to 40 CFR part 112 for the full text of the rule.

[122] The Plan certification requires that procedures for inspection and testing have been established by either a PE (in accordance with §112.3(d)(1)(iv)) or the owner or operator of a qualified facility (in accordance with either §112.6(a)(1)(iv) or §112.6(b)(1)(iv)).

7.2.4 Integrity Testing and Inspection for AFVO Bulk Storage Containers

The integrity testing requirements at §112.12(c)(6)(i), for animal fats and vegetable oil containers are identical to those described above at §112.8(c)(6).[123] To address differences in the way certain AFVOs may be stored and handled at a facility, the SPCC rule also provides differentiated, more flexible, alternative requirements at §112.12(c)(6)(ii) for AFVO containers that meet certain criteria. Facility owners/operators with AFVO containers that meet the specific criteria can conduct visual inspections of their containers on a regular schedule in lieu of meeting the integrity testing requirements found at §112.12(c)(6)(i). According to §112.12(c)(6)(ii), this flexibility applies to bulk storage containers that:

- Are subject to the Food and Drug Administration (FDA) regulations in 21 CFR part 110, *Current Good Manufacturing Practice in Manufacturing, Packing or Holding Human Food*;
- Are elevated;
- Are made from austenitic stainless steel;
- Have no external insulation; and
- Are shop-built.

The owner or operator is required to document in the SPCC Plan the procedures for visual inspections of AFVO bulk storage containers that are eligible for these differentiated requirements.

EPA developed this alternative to integrity testing based on the ways these oils are stored and handled at a facility. Each of the five criteria for this approach is described below and addresses the design, construction, and maintenance of bulk storage containers to minimize the potential for internal and external corrosion. Note that formal visual inspections may be used in lieu of integrity testing only when all five criteria are met.

[123] See *Section 7.5.2* for more information on deviating from the SPCC rule requirements based on environmental equivalence.

112.12(c)(6) Bulk storage container inspections.

(i) Except for containers that meet the criteria provided in paragraph (c)(6)(ii) of this section, test or inspect each aboveground container for integrity on a regular schedule and whenever you make material repairs. You must determine, in accordance with industry standards, the appropriate qualifications for personnel performing tests and inspections, the frequency and type of testing and inspections, which take into account container size, configuration, and design (such as containers that are: shop-built, field-erected, skid-mounted, elevated, equipped with a liner, double-walled, or partially buried). Examples of these integrity tests include, but are not limited to: Visual inspection, hydrostatic testing, radiographic testing, ultrasonic testing, acoustic emissions testing, or other systems of nondestructive testing. You must keep comparison records and you must also inspect the container's supports and foundations. In addition, you must frequently inspect the outside of the container for signs of deterioration, discharges, or accumulation of oil inside diked areas. Records of inspections and tests kept under usual and customary business practices satisfy the recordkeeping requirements of this paragraph.

(ii) For bulk storage containers that are subject to 21 CFR part 110, are elevated, constructed of austenitic stainless steel, have no external insulation, and are shop-fabricated, conduct formal visual inspection on a regular schedule. In addition, you must frequently inspect the outside of the container for signs of deterioration, discharges, or accumulation of oil inside diked areas. You must determine and document in the Plan the appropriate qualifications for personnel performing tests and inspections. Records of inspections and tests kept under usual and customary business practices satisfy the recordkeeping requirements of this paragraph (c)(6).

Note: The above text is only a brief excerpt of the rule. Refer to 40 CFR part 112 for the full text of the rule.

FDA Regulation at 21 CFR Part 110

The regulation at 21 CFR part 110, *Current Good Manufacturing Practice in Manufacturing, Packing or Holding Human Food* provides minimal elements for an integrity testing program, which address maintenance of the container, its foundations, and support structures.

FDA requires that facilities be constructed in such a manner that the floor, walls, and ceilings be adequately cleaned and kept clean and in good repair (21 CFR 110.20(b)(4)). Thus, the FDA requirements include procedures and practices, such as frequent monitoring of the floor around a bulk storage container, to ensure that cracks in the floor under and/or around the foundations of a bulk storage container do not accumulate food particles, organic matter, pests, or other potentially unsanitary substances that could lead to food contamination. These inspection requirements also address the SPCC rule requirement to inspect the container's foundations for structural integrity.

Additionally, all plant equipment, including the container's structural supports, must be designed and constructed to be adequately cleanable and properly maintained (21 CFR 110.40(a)). Periodic maintenance of the structural supports of a bulk storage container is also an oil spill preventive measure, especially inside a facility where mobile equipment (e.g., forklifts) can strike and damage the container and/or its structural supports.

FDA also requires that equipment (such as bulk storage containers) be designed, constructed, and used in such a way as to prevent food contamination by metal fragments or other potential contaminants (21 CFR 110.40(a)). Food-contact surfaces must be corrosion-resistant when in contact with food. Monitoring AFVOs for metal fragments as the oil exits the bulk storage container, either by sampling the oil itself for metal or by monitoring the inclusion prevention device for metal fragment accumulation, is a reasonable alternative approach to an internal inspection for corrosion. These regulatory requirements are likely to prevent the corrosion of the internal contact surface in food grade AFVO bulk storage containers.

For some bulk storage container configurations, external corrosion can be the primary concern with respect to their integrity. Significant corrosion of the exterior surface can occur from exposure to moisture and, in some cases, may be enhanced if insulation is present. Significant corrosion can also occur from overfills of oil and/or any associated substance(s) that have accumulated on the exterior surface, as well as from cleaning and sanitizing agents. FDA requires equipment that is in the manufacturing or food-handling area but does not come into contact with food to be constructed to be kept in a clean condition (21 CFR 110.40(c)). Since plant equipment used in the manufacturing or food-handling area must be designed to be kept clean and withstand the corrosive effects of cleaning agents, it is generally constructed of austenitic stainless steel.

In order to further address the potential for external corrosion and allow facility personnel to visually identify leaks and discharges, EPA requires that bulk oil storage containers which will be subject to visual inspections only be elevated, be made of austenitic stainless steel, have no external insulation and be shop fabricated. The following sections provide the rationales for these additional criteria.

Elevated Bulk Storage Containers

FDA recommends, but does not require, that all plant equipment be installed and maintained to facilitate its cleaning, including all adjacent spaces. According to 21 CFR 110.40(a), “all equipment *should* be so installed and maintained as to facilitate cleaning of the equipment and of all adjacent spaces.” In practice, an owner or operator of a facility implementing this recommended practice is likely to have a bulk storage container that is elevated off the floor.

Food equipment is generally designed to stand on legs, which elevates the plant equipment off the floor so that the space between the plant equipment and the floor can be cleaned. An elevated bulk storage container also facilitates complete drainage because the oil can be withdrawn from the lowest point in the container, so that foreign substances or materials do not accumulate and contaminate the food oil.

For the purposes of oil spill prevention, elevated bulk storage containers allow visual inspections for oil discharges all around the container. Additionally, self-draining containers that operate using gravity flow allow complete drainage and prevent substances other than oil (e.g., water) from accumulating at the bottom of the container, thus minimizing corrosion. The self-drainage design, in conjunction with the applicable regulatory requirements, is likely to prevent the corrosion of the internal contact surface in food-grade AFVO bulk storage containers.

Containers Made From Austenitic Stainless Steel

EPA limits the alternative approach to AFVO bulk storage containers made of austenitic stainless steel to ensure that containers are corrosion resistant and compatible with the materials stored. FDA requires that the food-contact surface be corrosion resistant under 21 CFR part 110 but does not explicitly require that AFVOs be stored in austenitic stainless steel bulk storage containers. For example, a carbon steel container with an internal liner may provide a corrosion resistant food contact surface to meet the FDA requirements. Although this meets the FDA regulatory requirements for food contact surfaces, the presence of a liner may also indicate that the oil in the bulk storage container is incompatible with the construction material of the bulk storage container.

In addition, non-homogenous container systems (e.g., containers with external insulation, external coating, mild-carbon steel shell, internal liner) are more complex than homogenous container systems (e.g., containers constructed solely of austenitic stainless steel) and may require additional inspection measures to ensure the integrity of the container. Finally, there is less chance of corrosion with austenitic stainless steel containers because they are compatible with cleaning agents and acidic detergents used to clean food and non-food contact surfaces.

Note that this limitation to austenitic stainless steel construction is only for an owner or operator who chooses to take advantage of the alternative compliance option in §112.12(c)(6)(ii). An SPCC Plan may still be certified with an environmental equivalence determination, in accordance with §112.7(a)(2) of the SPCC rule, for other types of bulk storage containers that are similarly corrosion resistant but do not meet all of the criteria described in §112.12(c)(6)(ii). *Chapter 3: Environmental Equivalence* discusses associated requirements.

Containers with No External Insulation

A minimum criterion for inspections is frequent monitoring of the exterior surface of a bulk storage container for corrosion and/or other mechanisms that can threaten a container's integrity. External insulation acts as a physical barrier to prevent effective visual examination of the exterior surface of the bulk storage container. Additionally, insulating materials on a bulk storage container and/or any associated equipment and piping can become damp when not properly sealed and cause significant corrosion, which may threaten the integrity of the container. Therefore, EPA included only containers with no external insulation in the alternative option for integrity testing.

Shop-Fabricated Containers

Shop-fabricated (i.e., shop-built) containers are containers that are shop-assembled in one piece before transport to the installation site. Shop-fabricated containers generally have lower volume capacities, smaller tank diameters, and a fewer number of welds than field-erected containers and are typically comprised of a single type of material with a single wall thickness.

The Steel Tank Institute's (STI) SP001, *Standard for the Inspection for Aboveground Storage Tanks,* establishes the scope and frequency for visual inspections of shop-fabricated containers. EPA limited the

alternative integrity testing option to shop-fabricated containers because they are simpler in design and construction (e.g., typically subject to less stress, and less likely to fail as a result of a brittle fracture) than field-erected containers.

7.2.5 Regular Leak Testing of Completely Buried Tanks

Completely buried metallic storage tanks installed on or after January 10, 1974 must be regularly leak tested. ‘‘Regular testing’’ means testing in accordance with industry standards or at a frequency sufficient to prevent leaks. Appropriate methods of testing should be selected based on good engineering practice and tests conducted in accordance with 40 CFR part 280.43 or a State program approved under 40 CFR part 281 are acceptable.

§§112.8(c)(4), 112.12(c)(4)

Protect any completely buried metallic storage tank installed on or after January 10, 1974 from corrosion by coatings or cathodic protection compatible with local soil conditions. You must regularly leak test such completely buried metallic storage tanks.

Note: The above text is only a brief excerpt of the rule. Refer to 40 CFR part 112 for the full text of the SPCC rule.

Leak testing is often referred to as “tank tightness testing.” Tank tightness tests include a wide variety of methods. Other terms used for these methods include "precision," "volumetric," and "nonvolumetric" testing. The features of tank tightness testing vary by method, as described in EPA Guidance on meeting UST system requirements:[124]

- Many tightness test methods are "volumetric" methods in which the change in product level in a tank over several hours is measured very precisely (in milliliters or thousandths of an inch).
- Other methods use acoustics or tracer chemicals to determine the presence of a hole in the tank. *With such methods, all of the factors in the following bullets may not apply.*
- For most methods, changes in product temperature also must be measured very precisely (thousandths of a degree) at the same time as level measurements, because temperature changes cause volume changes that interfere with finding a leak.
- For most methods, a net decrease in product volume (subtracting out volume changes caused by temperature) over the time of the test indicates a leak.
- The testing equipment is temporarily installed in the tank, usually through the fill pipe.
- The tank must be taken out of service for the test, generally for several hours, depending on the method.
- Many test methods require that the product in the tank be a certain level before testing, which often requires adding product from another tank on-site or purchasing additional product.

[124] For more information on tank tightness testing, see: http://www.epa.gov/oust/ustsystm/inventor.htm. For more information on preventing and detecting underground storage tank system leaks, see http://www.epa.gov/oust/prevleak.htm.

- Some tightness test methods require all of the measurements and calculations to be made by hand by the tester.
- Other tightness test methods are highly automated. After the tester sets up the equipment, a computer controls the measurements and analysis.
- A few methods measure properties of the product that are independent of temperature, such as the mass of the product, and so do not need to measure product temperature.
- Some automatic tank gauging systems are capable of meeting the regulatory requirements for tank tightness testing and can be considered as an equivalent method.

The SPCC Plan must describe the method and schedule for testing completely buried tanks.

7.2.6 Brittle Fracture Evaluation of Field-Constructed Aboveground Containers

Brittle fracture is a type of structural failure in aboveground steel tanks, characterized by rapid crack formation that can cause sudden tank failure. This, along with catastrophic failures such as those resulting from lightning strikes, seismic activity, or other such events, can cause the entire contents of a container to be discharged to the environment. Brittle fracture was most vividly illustrated by the splitting and collapse of a 3.8 million gallon (120-foot diameter) tank in Floreffe, Pennsylvania, which released approximately 750,000 gallons of oil into the Monongahela River in January 1988. A review of past failures due to brittle fracture shows that they typically occur:

- During an initial hydrotest,
- On the first filling in cold weather,
- After a change to lower temperature service, or
- After a repair/modification.

§112.7(i)

If a field-constructed aboveground container undergoes a repair, alteration, reconstruction, or a change in service that might affect the risk of a discharge or failure due to brittle fracture or other catastrophe, or has discharged oil or failed due to brittle fracture failure or other catastrophe, evaluate the container for risk of discharge or failure due to brittle fracture or other catastrophe, and as necessary, take appropriate action.

Note: The above text is only a brief excerpt of the rule. Refer to 40 CFR part 112 for the full text of the SPCC rule.

Storage tanks with a maximum shell thickness of one-half inch or less are not generally considered at risk for brittle fracture.[125, 126]

[125] McLaughlin, James E. 1991. "Preventing Brittle Fracture of Aboveground Storage Tanks – Basis for the Approach Incorporated into API 653." Case Studies: Sessions III and IV of the IIW Conference: Fitness for Purpose of Welded Structures. October 23-24, 1991, Key Biscayne, Florida, USA. Cosponsored by the American Welding Society, Welding Research Institute, Welding Institute of Canada, and International Institute of Welding. Published by the American Welding Society, Miami, Florida. Pages 90-110.

Section 112.7(i) of the SPCC rule requires that field-constructed aboveground containers that have undergone a repair or change in service that might affect the risk of a discharge due to brittle fracture or other catastrophe, or have had a discharge associated with brittle fracture or other catastrophe, be evaluated to assess the risk of such a discharge. Unless the original design shell thickness of the tank is less than one-half inch (see API 653, Section 5, and STI SP001, Appendix B), evidence of this evaluation should be documented in the facility's SPCC Plan.

Industry standards discuss methods for assessing the risk of brittle fracture failure for a field-erected aboveground container and for performing a brittle fracture evaluation. These include API 653, "*Tank Inspection, Repair, Alteration, and Reconstruction*," API RP 920 "*Prevention of Brittle Fracture of Pressure Vessels*," and API RP 579-1/ASME FFS-1, "*Fitness-for-Service*." API 653 includes a decision tree or flowchart for use by the owner/operator and PE in assessing the risk of brittle fracture.

7.2.7 Inspections of Piping at Onshore Facilities (Other than Oil Production Facilities)

Any piping installed prior to August 16, 2002 was subject to coating and cathodic protection if soil conditions warranted. However, in 2002, the SPCC rule was revised to require that all piping installed or replaced after August 16, 2002 be protectively wrapped and coated and also cathodically protected. The preamble to the final rule explains:

> *"…we believe that all soil conditions warrant protection of buried piping. We did not propose to make the requirement applicable to all existing piping because of the significant possibility that replacing all unprotected buried piping might cause more discharges than it would prevent. If soil conditions warrant such protection for existing piping, it is already required by the current rule." (67 FR 47123, July 17, 2002).*

Additionally, the SPCC rule has required since its original promulgation in 1973, that if any portion of buried piping at non-production facilities is exposed, the line must be inspected for deterioration, as per §§112.8(d)(1) and 112.12(d)(1). If corrosion damage is found, additional inspection or corrective action must be taken as needed.

Aboveground piping, valves, and appurtenances at non-production facilities must be regularly inspected, as per §§112.8(d)(4) and 112.12(d)(4) and in accordance with industry standards. In addition, buried piping must be integrity and leak tested at the time of installation, modification, construction, relocation, or replacement.

---

[126] API 653 4th Edition April 2009 Addendum 2 January 2012 Section 5.3.5.

§112.8(d) and 112.12(d)

(1) Provide buried piping that is installed or replaced on or after August 16, 2002, with a protective wrapping and coating. You must also cathodically protect such buried piping installations or otherwise satisfy the corrosion protection standards for piping in part 280 of this chapter or a State program approved under part 281 of this chapter. ***If a section of buried line is exposed for any reason, you must carefully inspect it for deterioration. If you find corrosion damage, you must undertake additional examination and corrective action as indicated by the magnitude of the damage.***

(4) Regularly inspect all aboveground valves, piping, and appurtenances. During the inspection you must assess the general condition of the items, such as flange joints, expansion joints, valve glands and bodies, catch pans, pipeline supports, locking of valves, and metal surfaces. You must also conduct integrity and leak testing of buried piping at the time of installation, modification, construction, relocation, or replacement.

Note: The above text is only a brief excerpt of the rule. Refer to 40 CFR part 112 for the full text of the SPCC rule. *Emphasis added.*

7.2.8 Inspection of Drainage Area and Bulk Storage Containers at Onshore Oil Production Facilities

Drainage Areas at Oil Production Facilities

The rule contains provisions for inspecting drainage from tank batteries or separation and treating areas. As per §112.9(b)(1), dike drains associated with tank batteries and separation and treating areas must be closed and sealed at all times and drainage areas must be inspected prior to draining in accordance with §112.8(c)(3)(ii), (iii), and (iv) as follows:

- Inspect the retained rainwater to ensure that its presence will not cause a discharge as described in §112.1(b);
- Open the bypass valve and reseal it following drainage under responsible supervision; and
- Keep adequate records of such events, for example, any records required under permits issued in accordance with 40 CFR 122.41(j)(2) and 122.41(m)(3).

Field drainage systems, such as road ditches, and oil traps, sumps or skimmers must be inspected at regular

§112.9(b)

(1) …Prior to drainage, you must inspect the diked area and take action as provided in §112.8(c)(3)(ii), (iii), and (iv). You must remove accumulated oil on the rainwater and return it to storage or dispose of it in accordance with legally approved methods.

(2) Inspect at regularly scheduled intervals field drainage systems (such as drainage ditches or road ditches), and oil traps, sumps, or skimmers, for an accumulation of oil that may have resulted from any small discharge. You must promptly remove any accumulations of oil.

§112.9(c)

(3) Except as described in paragraph (c)(5) of this section for flow-through process vessels and paragraph (c)(6) of this section for produced water containers and any associated piping and appurtenances downstream from the container, periodically and upon a regular schedule visually inspect each container of oil for deterioration and maintenance needs, including the foundation and support of each container that is on or above the surface of the ground.

Note: The above text is only a brief excerpt of the rule. Refer to 40 CFR part 112 for the full text of the SPCC rule.

intervals (§112.9(b)(2)) for accumulations of oil which must be promptly removed.

Bulk Storage Containers at Oil Production Facilities

Each bulk storage container (e.g., oil stock tanks,[127] flow-through process vessels, and produced water containers) at an oil production facility must be inspected periodically and upon a regular schedule for signs of deterioration and maintenance needs in accordance with §112.9(c)(3), including the foundation and support of each container that is on or above the surface of the ground. This inspection is intended to be a routine walk-around where the inspector looks at the container and supports and foundations for any evidence of damage, corrosion, or leaks. The inspection procedures and schedule must be documented in the SPCC Plan and inspections conducted in accordance with the Plan, good engineering practices, and any appropriate industry standards or recommended practices identified in the Plan.

The inspection should occur on an ongoing routine basis and be conducted by qualified personnel. Before the PE certifies the SPCC Plan in accordance with §112.3(d),[128] he must consider applicable industry standards and verify that appropriate procedures for inspections and tests have been established. API has developed Recommended Practice 12R1 "Recommended Practice for Setting, Maintenance, Inspection, Operation and Repair of Tanks in Production Service" that includes inspection procedures for tanks employed in onshore oil production service and in certain circumstances includes non-destructive testing elements in addition to visual inspection.

Additionally, the owner or operator of an onshore oil production facility must conduct ***integrity testing*** for any bulk storage containers for which he determines secondary containment is impracticable. The Plan must follow the provision of §112.7(d) and clearly explain why secondary containment measures are not practicable; for bulk storage containers, conduct both periodic integrity testing of the containers and periodic integrity and leak testing of the valves and piping; and, unless the facility owner or operator has submitted a response plan under §112.20, provide the following in the Plan:

- An oil spill contingency plan following the provisions of 40 CFR part 109, and
- A written commitment of manpower, equipment, and materials required to expeditiously control and remove any quantity of oil discharged that may be harmful.

7.2.9 Alternative Inspection requirements for Flow-through Process Vessels at Oil Production Facilities

Flow-through process vessels at oil production facilities are bulk storage containers and are therefore subject to the bulk storage container requirements of §112.9(c) including specific secondary containment

[127] A stock tank is a storage tank for oil production after the oil has been treated (Schlumberger Oil Field Glossary http://www.glossary.oilfield.slb.com/)

[128] In the case of a qualified facility, the owner or operator would certify the SPCC Plan in accordance with either §112.6(a)(1) or 112.6(b)(1), as applicable.

requirements of §112.9(c)(2). However, facility owners and operators have the option to implement alternative requirements in accordance with §112.9(c)(5) in lieu of providing sized secondary containment.

As an alternative to the sized secondary containment and inspection requirements for bulk storage containers at oil production facilities found at §§112.9(c)(2) and 112.9(c)(3), an oil production facility owner or operator may opt to provide general secondary containment in accordance with §112.7(c), and comply with the following requirements for flow-through process vessels at oil production facilities:

- **Periodically and on a regular schedule visually inspect and/or test flow-through process vessels and associated components (such as dump valves) for leaks, corrosion, or other conditions that could lead to a discharge, as described in §112.1(b).** Regular inspections are necessary to ensure that any leak, or potential for a leak, is detected promptly enough to prevent a discharge of the entire contents of the separation or treating equipment. This is especially true for components that typically cause discharges, such as dump valves. These requirements are consistent with the inspection requirements for bulk storage containers under §112.9(c)(3). (73 FR 74279, December 5, 2008). Records of inspections or tests must be maintained in accordance with §112.7(e). This requirement is necessary to increase the likelihood that a discharge to navigable waters or adjoining shorelines will be prevented or detected promptly.

> **Tip – Oil discharge**
>
> Note that the SPCC rule defines *discharge* to include any spilling, leaking, pumping, pouring, emitting, emptying, or dumping of oil… and not just a discharge as described in §112.1(b) (i.e., a discharge to navigable waters or adjoining shorelines.)
>
> Therefore corrective action and removal must be initiated before the discharge reaches navigable waters or adjoining shorelines.

- **Take corrective action or make repairs to flow-through process vessels and any associated components as indicated by regularly scheduled visual inspections, tests, or evidence of an oil discharge.** Corrective action/repairs ensure that equipment is adequately maintained to prevent discharges from flow-through process vessels and associated components. Needed repairs that are identified during regular inspections should be scheduled in a timely manner to prevent a discharge.

- **Promptly remove or initiate actions to stabilize and remediate any accumulations of oil discharges associated with flow-through process vessels.** If a leak or spill is identified during an inspection, corrective action is necessary to ensure that a discharge does not impact navigable waters or adjoining shorelines. The owner or operator must remove, or stabilize and remediate, oil accumulations from flow-through process vessels and any associated components in order to prevent a discharge as described in §112.1(b). This may include removal of oil-contaminated soil. Removal of recoverable oil may be combined with physical, chemical, and/or biological treatment methods to address any residual oil. These treatment methods must be consistent with other Federal, state or local requirements as applicable, and must be properly managed to prevent a discharge as described in §112.1(b). Disposal of oil and/or oil-contaminated media

must be in accordance with applicable Federal, state, and local requirements (see 73 FR 74279, December 5, 2008). The SPCC Plan must describe the methods of disposal of recovered materials in accordance with applicable legal requirements under §112.7(a)(3)(v).

These additional requirements are necessary because oil production facilities are generally unattended, so there is a lower potential to immediately discover and correct a discharge than at a non-production facility, which would typically be attended during hours of operation. The owner or operator of the facility may choose to deviate from the measures described above by substituting environmentally equivalent alternatives. The alternative measure chosen, and certified by a PE, must represent good engineering practice and must achieve environmental protection equivalent to the SPCC rule requirement as required in §112.7(a)(2). For more information on environmental equivalence, see *Chapter 3: Environmental Equivalence*, *Section 3.3.8*. For more information on how to determine appropriate secondary containment capacity to comply with the general secondary containment requirements of §112.7(c), see *Chapter 4: Secondary Containment and Impracticability*, *Section 4.8.1.*

§112.9(c)(5)

Flow-through process vessels. The owner or operator of a facility with flow-through process vessels may choose to implement the alternate requirements as described below in lieu of sized secondary containment required in paragraphs (c)(2) and (c)(3) of this section.

(i) Periodically and on a regular schedule visually inspect and/or test flow-through process vessels and associated components (such as dump valves) for leaks, corrosion, or other conditions that could lead to a discharge as described in §112.1(b).

(ii) Take corrective action or make repairs to flow-through process vessels and any associated components as indicated by regularly scheduled visual inspections, tests, or evidence of an oil discharge.

(iii) Promptly remove or initiate actions to stabilize and remediate any accumulations of oil discharges associated with flow-through process vessels.

(iv) If your facility discharges more than 1,000 U.S. gallons of oil in a single discharge as described in §112.1(b), or discharges more than 42 U.S. gallons of oil in each of two discharges as described in §112.1(b) within any twelve month period, from flow-through process vessels (excluding discharges that are the result of natural disasters, acts of war, or terrorism) then you must, within six months from the time the facility becomes subject to this paragraph, ensure that all flow-through process vessels subject to this subpart comply with §112.9(c)(2) and (c)(3).

Note: The above text is an excerpt of the SPCC rule. Refer to 40 CFR part 112 for the full text of the rule.

Tip – Discharges from flow-through process vessels

If flow-through process vessels at the facility cause a single discharge of oil to navigable waters or adjoining shorelines exceeding 1,000 U.S. gallons, or two discharges of oil to navigable waters or adjoining shorelines each exceeding 42 U.S. gallons within any 12-month period (excluding discharges that are the result of natural disasters, acts of war, or terrorism), then the owner/operator must, within six months:

- Install sized secondary containment with sufficient freeboard for precipitation for all flow-process vessels at the facility,
- Periodically and upon a regular schedule visually inspect each container of oil for deterioration and maintenance needs, including the foundation and support of each container that is on or above the surface of the ground, and
- Submit a report to the Regional Administrator within 60 days of the discharge(s) and to the appropriate state agency or agencies in charge of oil pollution control activities, as per Section 112.4(a).

The report must include the name of the facility; the name of the owner or operator; location of the facility; maximum storage or handling capacity of the facility and normal daily throughput; corrective action and countermeasures taken, including a description of equipment repairs and replacements; an adequate description of the facility, including maps, flow diagrams, and topographical maps, as necessary; the cause of the discharge(s), including a failure analysis of the system or subsystem in which the failure occurred; additional preventive measures taken or contemplated to minimize the possibility of recurrence; and any other information as the Regional Administrator may reasonably require pertinent to the Plan or discharge.

7.2.10 Alternative Inspection Requirements for Produced Water Containers at Oil Production Facilities

Like flow-through process vessels, produced water containers are bulk storage containers and are therefore subject to the bulk storage container requirements of §112.9(c) for oil production facilities, including specific secondary containment requirements of §112.9(c)(2).

However, differentiated inspections and testing requirements apply in cases where the facility owner or operator takes advantage of the option outlined in §112.9(c)(6) in lieu of providing sized secondary containment for produced water containers.

§112.9(c)

(6) For each produced water container, comply with §112.9(c)(1) and (c)(4); and §112.9(c)(2) and (c)(3), or comply with the provisions of the following paragraphs (c)(6)(i) through (v):

(i) Implement, on a regular schedule, a procedure for each produced water container that is designed to separate the free-phase oil that accumulates on the surface of the produced water. Include in the Plan a description of the procedures, frequency, amount of free-phase oil expected to be maintained inside the container, and a Professional Engineer certification in accordance with §112.3(d)(1)(vi). Maintain records of such events in accordance with §112.7(e). Records kept under usual and customary business practices will suffice for purposes of this paragraph. If this procedure is not implemented as described in the Plan or no records are maintained, then you must comply with §112.9(c)(2) and (c)(3).

(ii) On a regular schedule, visually inspect and/or test the produced water container and associated piping for leaks, corrosion, or other conditions that could lead to a discharge as described in §112.1(b) in accordance with good engineering practice.

(iii) Take corrective action or make repairs to the produced water container and any associated piping as indicated by regularly scheduled visual inspections, tests, or evidence of an oil discharge.

(iv) Promptly remove or initiate actions to stabilize and remediate any accumulations of oil discharges associated with the produced water container.

(v) If your facility discharges more than 1,000 U.S. gallons of oil in a single discharge as described in §112.1(b), or discharges more than 42 U.S. gallons of oil in each of two discharges as described in §112.1(b) within any twelve month period from a produced water container subject to this subpart (excluding discharges that are the result of natural disasters, acts of war, or terrorism) then you must, within six months from the time the facility becomes subject to this paragraph, ensure that all produced water containers subject to this subpart comply with §112.9(c)(2) and (c)(3).

Note: The above text is only a brief excerpt of the rule. Refer to 40 CFR part 112 for the full text of the SPCC rule.

As an alternative to the sized secondary containment requirements and inspection requirements for bulk storage containers at oil production facilities found at §§112.9(c)(2) and 112.9(c)(3), an oil production facility owner or operator may opt to provide general secondary containment in accordance with §112.7(c) for produced water containers, and comply with the following additional requirements:

Implement on a regular schedule a procedure for each produced water container that is designed to separate the free-phase oil that accumulates on the surface of the produced water (e.g., skimming program).

- The facility owner or operator must implement a process and/or procedure for the produced water container (s) that is designed to remove the free-phase oil that accumulates on the surface of the produced water container. This process or procedure must be implemented on a regular schedule so that the amount of free phase oil that collects in produced water containers does not exceed the amounts that can be managed by the general secondary containment system designed by the PE to address the typical failure mode, and the most likely quantity of oil that would be discharged.

- The SPCC Plan must include a description of the free-phase oil separation and removal process or procedure, the frequency at which the procedure is implemented or operated, the maximum amount of free-phase oil expected to accumulate in the container, and a description of the adequacy of the general secondary containment approach for the produced water container, including the anticipated typical failure mode and the method, design, and capacity for general secondary containment. Additionally, the owner or operator must keep records of the implementation of these procedures in accordance with §112.7(e). (see 73 FR 74287, December 5, 2008).

- Section 112.3(d)(1)(vi) requires the PE to certify that the oil removal process or procedure for produced water containers is designed according to good engineering practice to reduce the accumulation of free-phase oil, and that the process or procedure and frequency for required inspections, maintenance, and testing have been established. When developing this procedure and designing general secondary containment for produced water containers, the PE should carefully consider the length of time the facility is unattended and the flow rate of produced water into the container to ensure that the most likely discharge of the produced water container is discovered before it escapes secondary containment.

- Furthermore, this oil removal process or procedure is essential for reducing the amount of free-phase oil in the produced water container to ensure that the secondary containment system is appropriate to contain a discharge before cleanup can occur. Therefore, EPA inspectors should review records of the implementation of the process or procedure to ensure that the Plan is being properly implemented. If, upon inspection, it is discovered that the removal process or procedure is not implemented, then the Regional Administrator may require amendments to the Plan that include providing sized secondary containment for produced water containers at the facility (§112.4(d)).

> **Tip – Oil discharge**
>
> Note that the SPCC rule defines *discharge* to include any spilling, leaking, pumping, pouring, emitting, emptying, or dumping of oil… and not just a discharge as described in §112.1(b) (i.e., a discharge to navigable waters or adjoining shorelines).
>
> Therefore, corrective action and removal must be initiated when the container is leaking but before the discharge reaches navigable waters or adjoining shorelines.

On a regular schedule, visually inspect and/or test the produced water container and associated piping for leaks, corrosion, or other conditions that could lead to a discharge as described in §112.1(b) in accordance with good engineering practice.

- These inspections and/or tests are to be done in conjunction with procedures implemented on a regular schedule to separate the free-phase oil that accumulates on the surface of the produced water, and are meant to ensure that the produced water container will not cause a discharge as described in §112.1(b) were its contents to be released. The inspections and tests may involve, for example, frequently inspecting the content of the produced water container to assess the

amount of oil that has accumulated. Records of inspections or tests must be maintained in accordance with §112.7(e). This requirement is necessary to increase the likelihood that a discharge to navigable waters or adjoining shorelines will be prevented or detected promptly when general secondary containment measures are used instead of sized secondary containment.

Take corrective action or make repairs to the produced water container and any associated piping as indicated by regularly scheduled visual inspections, tests, or evidence of an oil discharge.

- Corrective action is necessary to prevent a discharge from occurring, as well as in response to a discharge. This measure is intended to prevent discharges by ensuring that produced water containers are adequately maintained.

Promptly remove or initiate actions to stabilize and remediate any accumulations of oil discharges associated with the produced water container.

- This requirement is intended to ensure the removal of oil accumulations around the container and any associated piping and appurtenances that may contribute to a discharge as described in §112.1(b). This may include removal of oil-contaminated soil as a means of preventing oil from becoming a discharge as described in §112.1(b). Disposal of oil and/or oil-contaminated media must be in accordance with applicable Federal, state, and local requirements.

The owner or operator of the facility may choose to deviate from the measures described above by substituting environmentally equivalent alternatives, but must still comply with the secondary containment requirements in §112.7(c). The alternative measure chosen, and certified by a PE, must represent good engineering practice and must achieve environmental protection equivalent to the SPCC rule requirement, as required in §112.7(a)(2). For more information on environmental equivalence see *Chapter 3: Environmental Equivalence, Section 3.3.8*. For more information on how to determine appropriate capacity for secondary containment systems to comply with the general secondary containment requirements of §112.7(c) see *Chapter 4: Secondary Containment and Impracticability*, *Section 4.8.2.*

7.2.11 Inspection of Facility Transfer Operations at Onshore Oil Production Facilities

All aboveground valves and piping at facility transfer operations must be inspected on a regular schedule to check the condition of all components (§112.9(d)(1) and (2)).

§112.9(d)

(1) Periodically and upon a regular schedule inspect all aboveground valves and piping associated with transfer operations for the general condition of flange joints, valve glands and bodies, drip pans, pipe supports, pumping well polish rod stuffing boxes, bleeder and gauge valves, and other such items.

(2) Inspect saltwater (oil field brine) disposal facilities often, particularly following a sudden change in atmospheric temperature, to detect possible system upsets capable of causing a discharge.

Note: The above text is only a brief excerpt of the rule. Refer to 40 CFR part 112 for the full text of the SPCC rule.

Inspections ''upon a regular schedule'' means in accordance with industry standards or at a frequency sufficient to prevent discharges as described in §112.1(b). Whatever frequency of inspections is selected must be documented in the Plan (67 FR 47130, July 17, 2002). The inspection requirement includes transfer operations, including but not limited to all aboveground valves and piping, the general condition of flange joints, valve glands and bodies, drip pans, pipe supports, pumping well polish rod stuffing boxes, bleeder and gauge valves, and other such items. Saltwater or oil field brine disposal facilities also must be inspected often and particularly following a sudden change in atmospheric temperature.

7.2.12 Maintenance of Flowlines and Intra-Facility Gathering Lines

The purpose of a flowline/intra-facility gathering line maintenance program is to help prevent oil discharges from this piping. Common causes of such discharges include mechanical damage (e.g., impact or rupture) and corrosion. The SPCC rule requires that the scope of a maintenance program include written procedures and other measures to prevent corrosion or other conditions that could cause a discharge. An effective flowline/intra-facility gathering line maintenance program is necessary to detect a discharge in a timely manner so that the oil discharge response operations described in a contingency plan may be implemented effectively.

§112.9(d)(4)

Prepare and implement a written program of flowline/intra-facility gathering line maintenance. The maintenance program must address your procedures to:

(i) Ensure that flowlines and intra-facility gathering lines and associated valves and equipment are compatible with the type of production fluids, their potential corrosivity, volume, and pressure, and other conditions expected in the operational environment.

(ii) Visually inspect and/or test flowlines and intra-facility gathering lines and associated appurtenances on a periodic and regular schedule for leaks, oil discharges, corrosion, or other conditions that could lead to a discharge as described in §112.1(b). For flowlines and intra-facility gathering lines that are not provided with secondary containment in accordance with §112.7(c), the frequency and type of testing must allow for the implementation of a contingency plan as described under part 109 of this chapter.

(iii) Take corrective action or make repairs to any flowlines and intra-facility gathering lines and associated appurtenances as indicated by regularly scheduled visual inspections, tests, or evidence of a discharge.

(iv) Promptly remove or initiate actions to stabilize and remediate any accumulations of oil discharges associated with flowlines, intra-facility gathering lines, and associated appurtenances.

Note: The above text is an excerpt of the SPCC rule. Refer to 40 CFR part 112 for the full text of the rule.

The SPCC rule specifically requires a written maintenance program that addresses procedures to:

- Ensure that flowlines and intra-facility gathering lines and associated valves and equipment are compatible with the type of production fluids, their potential corrosivity, volume, pressure, and other operating conditions.

- Visually inspect and/or test flowlines and intra-facility gathering lines and associated appurtenances on a periodic and regular schedule for leaks, oil discharges, corrosion, or other conditions that could lead to a discharge as described in §112.1(b). For flowlines and intra-facility gathering lines that are not provided with secondary containment in accordance with §112.7(c), the frequency and type of testing must allow for the implementation of a contingency plan as described under 40 CFR part 109.

- Take corrective action or make repairs to any flowlines and intra-facility gathering lines and associated appurtenances as indicated by regularly scheduled visual inspections, tests, or evidence of a discharge. Note that the SPCC rule defines *discharge* to include any spilling, leaking, pumping, pouring, emitting, emptying, or dumping of oil; not just a discharge as described in §112.1(b) (i.e., a discharge to navigable waters or adjoining shorelines). Therefore, corrective action and removal must be initiated before the discharge reaches navigable waters or adjoining shorelines.

- Promptly remove or initiate actions to stabilize and remediate any accumulations of oil discharges associated with flowlines, intra-facility gathering lines, and associated appurtenances. The owner or operator of the facility has both the responsibility and flexibility to outline an inspection program under §112.9(d)(4)(ii) that puts the timeframe for ‘‘prompt removal’’ in the context of the inspection frequency (73 FR 74276, December 5, 2008).

Oil production facility owners or operators must either provide secondary containment for flowlines and intra-facility gathering lines in accordance with §112.7(c) or comply with alternative measures for these lines under §112.9(d)(3). Unless the facility owner/operator has submitted a response plan under §112.20, the alternative measures include an oil spill contingency plan following the provisions of 40 CFR part 109 and a written commitment of manpower, equipment, and materials required to expeditiously control and remove any quantity of oil discharged that might be harmful.

The frequency and type of inspections and/or tests must allow for the implementation of the contingency plan prepared in accordance with 40 CFR part 109 or the FRP. This measure is intended to ensure that any discharges, potential problems or conditions related to the flowline/intra-facility gathering line that could lead to a discharge will be promptly discovered. This is because an oil spill contingency plan cannot be effective unless the discharge is discovered in a timely manner so that the response operations described in the contingency plan can be implemented.

Additionally, the results of inspections or tests will inform the owner/operator of any corrections or repairs that need to be made. Corrective action is necessary in order to prevent a discharge as described in §112.1(b) by ensuring that flowlines and intra-facility gathering lines are well maintained and by ensuring prompt corrective actions or repairs in response to conditions found during the inspection/testing of the flow and intra-facility gathering lines.

The Plan preparer certifying the Plan will typically establish the scope and frequency of inspections, tests, and preventive maintenance based on industry standards, manufacturer's recommendations, and other sources of good engineering practice. This guidance refers to selected relevant industry standards that describe methods used to test the integrity of piping, such as API 570[129] and ASME B31.4. While these standards are not specific to flowlines and intra-facility gathering lines, they may serve as guidance. There is currently no published industry standard for a flowline or intra-facility gathering line maintenance program; however, a standard may be developed in the future. If an industry standard is developed that meets all of the requirements described in §112.9(d)(4) then the PE may follow that standard when developing a flowline/intra-facility gathering line program for the facility.

Due to changes in flowrates and corrosivity of production fluids over time in an oil field, the frequency of inspection may need to change over the lifetime of the well in order to prevent discharges. For buried piping, a facility owner or operator should develop an inspection program to identify evidence of leaks at the surface or other conditions that may lead to a discharge to navigable waters or adjoining shorelines. The provisions for a flowline/intra-facility gathering line maintenance program in §112.9(d)(4) are eligible for environmental equivalence as discussed in more detail in *Chapter 3: … Equivalence, Section 3.3.5.*

7.2.13 Inspection and Corrective Action Requirements at Offshore Facilities

For offshore facilities, the SPCC rule includes inspection requirements for oil collection equipment, sumps, pollution prevention equipment, and piping.

Section 112.11(b) requires that the facility include oil collection equipment to prevent and control small oil discharges and direct facility drains toward a central collection sump to prevent a discharge as described in §112.1(b). When drains and sumps are not practicable, oil must be removed from collection equipment as often as necessary to prevent an overflow. The facility owner/operator can use inspections as directed in §112.11(h) and (i) to determine the frequency of oil removal activities to prevent overflows from this collection equipment.

Facilities employing a sump system must provide adequately sized sump and drains; make available a spare pump to remove liquid from the sump and assure that oil does not escape; and employ a regularly scheduled preventive maintenance inspection and testing program to assure reliable operation of the liquid removal system and pump start-up device. Redundant automatic sump pumps and control devices may be required on some installations (§112.11(c)). In accordance with §112.11(h), the offshore facility owner/operator must prepare and maintain at the facility a written procedure within the Plan for inspecting and testing pollution prevention equipment and systems and then implement that procedure as directed in §112.11(i). The rule requires the owner or operator to conduct testing and inspection of the pollution prevention equipment and systems at the facility on a scheduled periodic basis, commensurate with the complexity, conditions, and circumstances of the facility and any other appropriate regulations and to use simulated discharges for testing and inspecting human and equipment pollution control and countermeasure systems.

[129] API 570 3th Edition November 2009

Finally, the owner/operator must maintain sub-marine piping appurtenant to the facility in good operating condition at all times and inspect or test such piping for failures periodically and according to a schedule in accordance with §112.11(p).

§112.11 Relevant sections

(b) Use oil drainage collection equipment to prevent and control small oil discharges around pumps, glands, valves, flanges, expansion joints, hoses, drain lines, separators, treaters, tanks, and associated equipment. You must control and direct facility drains toward a central collection sump to prevent the facility from having a discharge as described in § 112.1(b). Where drains and sumps are not practicable, you must remove oil contained in collection equipment as often as necessary to prevent overflow.

(c) For facilities employing a sump system, provide adequately sized sump and drains and make available a spare pump to remove liquid from the sump and assure that oil does not escape. You must employ a regularly scheduled preventive maintenance inspection and testing program to assure reliable operation of the liquid removal system and pump start-up device. Redundant automatic sump pumps and control devices may be required on some installations.

(h) Prepare and maintain at the facility a written procedure within the Plan for inspecting and testing pollution prevention equipment and systems.

(i) Conduct testing and inspection of the pollution prevention equipment and systems at the facility on a scheduled periodic basis, commensurate with the complexity, conditions, and circumstances of the facility and any other appropriate regulations. You must use simulated discharges for testing and inspecting human and equipment pollution control and countermeasure systems.

(p) Maintain sub-marine piping appurtenant to the facility in good operating condition at all times. You must periodically and according to a schedule inspect or test such piping for failures. You must document and keep a record of such inspections or tests at the facility.

Note: The above text is only a brief excerpt of the rule. Refer to 40 CFR part 112 for the full text of the SPCC rule.

7.3 Role of Industry Standards and Recommended Practices in Meeting SPCC Requirements

The SPCC rule does not require the use of a specific industry standard for conducting inspections, evaluations, and integrity testing of bulk storage containers and other equipment at a facility. Rather, the rule provides flexibility in a facility owner/operator's use of industry standards to comply with the requirements, consistent with good engineering practice and as reviewed by the PE certifying the Plan.

To develop an appropriate inspection, evaluation, and testing program for an SPCC-regulated facility, the PE must consider applicable industry standards (§112.3(d)(1)(iii)). If the facility owner or operator indicates in the SPCC Plan that he intends to use a standard to comply with a particular rule requirement (e.g., integrity testing), then it is mandatory to implement the relevant portions of the standard (i.e., those that address integrity testing of the container). In this case, if the standard is more stringent than federal regulations (e.g., for recordkeeping retention requirements), the standard would take precedent. A summary is provided in *Table 7-5* later in this chapter to assist EPA inspectors in reviewing the relevance of particular industry standards to the

equipment observed at an SPCC-regulated facility. The SPCC Plan should clearly identify the standard used to comply with the SPCC requirements. As required in §112. 5(b), facility owners/operators must review their SPCC Plan at least once every five years to include more effective prevention and control technology. This may provide an opportunity to consider revisions to industry standards and determine whether these revisions impact implementation of the SPCC Plan.

Tip for Qualified Facilities

The Plan preparer must ensure that the Plan is prepared in accordance with accepted and sound industry practices and standards; and that procedures for required inspections and testing are established in accordance with industry inspection and testing standards or recommended

Industry standards typically apply to containers built according to a specified design (API 653, for example, applies to tanks constructed in accordance with API 650 or API 12C specifications); the standards[130] describe the scope, frequency, and methods for evaluating the suitability of the containers for continued service. This assessment usually considers performance relative to specified minimum criteria, such as remaining shell thickness or ability to maintain pressure. The standards specify certain visual inspections, evaluations, assessments, and tests that must be performed by inspectors certified by the standard-setting organizations (e.g., American Petroleum Institute, Steel Tank Institute).

In the preamble to the 2002 SPCC rule amendments, EPA provided examples of industry standards that may constitute good engineering practice for assessing the integrity of different types of containers for oil storage (67 FR 47120, July 17, 2002). Compliance with other federal requirements and industry standards may also meet SPCC inspection, evaluation, and testing requirements. For example, the U.S. Department of Transportation (DOT) regulates containers used to transport hazardous materials, including certain oil products; mobile/portable containers that leave a facility are subject to the DOT construction and continuing qualification and maintenance requirements (49 CFR part 178 and 49 CFR part 180). Measures that comply with these DOT requirements may be used by the facility owner and operator and by the certifying PE as references of good engineering practice for assessing the fitness for service of mobile/portable containers.

Table 7-2 summarizes key elements of industry standards and recommended practices commonly used for testing aboveground storage tanks (ASTs). *Table 7-3* summarizes key elements of standards and recommended practices used for testing piping and other equipment. *Section 7.7* provides a more detailed description of the standards listed in the tables. Other industry standards, beyond those detailed in this chapter, exist for specific equipment or purposes. Many of these are cross-referenced in API 653, including publications and standards from other organizations such as the American Society for Testing and Materials (ASTM), the American Society for Non-Destructive Testing (ASNT), and the American Society of Mechanical Engineers (ASME). Other organizations, such as the National Fire Protection Association (NFPA), the National Association of Corrosion Engineers (NACE), and the Underwriters Laboratory (UL), also provide critical information on various container types and appurtenances. Note that this Chapter reflects industry standards in effect at the time EPA revised this Guidance; however, industry standards are subject to change.

[130] See *Section 7.7* of this chapter for more information on these publications.

Table 7-2: Summary of industry standards and recommended practices (RP) for ASTs.

	API 653[131]	STI SP001[132]	API RP 575[133]	API RP 12R1[134]
Equipment covered	Field-fabricated, welded, or riveted ASTs operating at atmospheric pressure and built according to API 650 and API 12C.	ASTs including shop-fabricated and field-erected tanks and portable containers and containment systems with contents at atmospheric pressure and up to 200°F (93.3°C).	Atmospheric and low-pressure ASTs that have been in service.	Atmospheric ASTs employed in oil and gas production, treating, and processing.
Scope	Inspection and design; fitness for service; repair and alterations; risk.	Inspection and evaluation of ASTs.	Inspection and repair of tanks.	Setting, connecting, maintaining, operating, inspecting, and repairing tanks.
Inspection interval	*Certified inspections*: Dependent on tank's service history. Intervals from 5 to 30 years. *Owner inspections*: monthly.	*Certified inspections*: Inspection intervals and scope based on tank size and configuration. *Owner inspections*: monthly, quarterly, and yearly.	Same as API 653 and API RP 12R1.	Scheduled and unscheduled internal and external inspections conducted as per Table 1 and Table 2 of the Recommended Practice, based on tank conditions.
Inspection performed by	Authorized inspector, tank owner.	Certified inspector (either by API 653 with STI adjunct certification or STI) or owner's inspector.	Same as API 653.	Competent person or qualified inspector, as defined in recommended practice.
Applicable section of this Guidance	*Section 7.7.1*	*Section 7.7.2*	*Section 7.7.3*	*Section 7.7.5*

131 API 653 4th Edition April 2009 Addendum 2 January 2012

132 STI SP001 5th Edition September 2011

133 API 575 2nd Edition May 2005

134 AP 12R1 5th Edition April 2008

Table 7-3: Summary of industry standards and recommended practices (RP) for piping, valves, and appurtenances.

	API 570[135]	API RP 574[136]	API RP 1110[137]	ASME B31.3[138]	ASME B31.4[139]
Equipment covered	In-service aboveground and buried metallic piping	Piping, tubing, valves and fittings in petroleum refineries and chemical plants	Steel pipelines for the transportation of gas, petroleum gas, hazardous liquids, highly volatile liquids or carbon dioxide (pressure testing)	New process piping for oil, petrochemical, chemical, and other industries	Pressure piping for liquid hydrocarbons and other liquids
Scope	Inspection, repair, alteration, and rerating procedures	Inspection practices, intervals and records.	Planning, implementation and records and drawings for pressure testing	Safety requirements for design, construction and testing	Safe design, construction, inspection, testing, operation, and maintenance
Inspection interval	Based on possible forms of degradation and consequence of failure, maximum of 10 years	Based on five factors including consequences of a failure as classified by API 570	Not specified	As part of quality assurance function. Differentiates between inspection and examination	Not specified
Inspection performed by	Authorized piping inspector	Authorized piping inspector	Qualified by both training and experience, considering six factors	Qualified Inspector, as defined in standard	Qualified Inspector, as defined in standard
Applicable section of this Guidance	*Section 7.7.6*	*Section 7.7.7*	*Section 7.7.8*	*Section 7.7.11*	*Section 7.7.13*

135 API 570 3rd Edition November 2009

136 API 574 3rd Edition November 2009

137 API 1110 5th Edition June 2007

138 ASME B31.3 3rd Edition 2008

139 ASME B31.4 2006

7.4 Baselining

Industry standards, such as API 653 and STI SP001, contain minimum requirements to inspect aboveground containers and criteria to assess each container's suitability for continued service. The baseline and suitability evaluation provides information on the container's existing condition relative to the design metal thickness and the rate of metal loss from corrosion as well as the anticipated remaining service. Some facilities may not have yet performed integrity testing of their tanks. In this case, developing an appropriate integrity testing program will require assessing baseline conditions for these tanks. This "baseline" will provide information on the existing condition of the tank shell and tank bottom, or other factors, in order to establish a regular inspection schedule.

Section 112.7 of the rule requires that if any facilities, procedures, methods, or equipment are not yet fully operational, the SPCC Plan must explain the details of installation and operational start-up; this applies to the inspection and testing programs required by the rule. If an owner or operator has yet to implement the integrity testing program, the SPCC Plan should establish and document a schedule (in accordance with good engineering practice and the introductory paragraph of §112.7) that describes the projected implementation of the integrity testing program for the aboveground bulk storage containers at the facility. The owner or operator must then implement the inspection program in accordance with the SPCC Plan. The PE is responsible for determining the scope and frequency of testing when certifying, in accordance with §112.3(d), that the SPCC Plan is consistent with industry standards and is appropriate for the facility.

The implementation of the testing program should be in accordance with industry standards and establish appropriate inspection priorities among multiple containers at a facility. For instance, special consideration may be discussed in the Plan for containers for which the age and existing condition is not known (no baseline or only partial information exists); older containers; or those in more demanding service. These higher priority containers may be targeted for inspection in the schedule before other aboveground containers where the baseline information is known.

Is a baseline necessary when the standard requires only visual inspections?

No, if the industry standard only requires visual inspections for the container (e.g., certain shop-built containers) then a baseline is not necessary. The standard establishes a frequency for visual inspections rather than basing the interval on the container's corrosion rate. On the other hand, a baseline is necessary for most non-destructive testing protocols, because the container's corrosion rate impacts the frequency/interval of future formal integrity testing inspections.

Owners and operators need to refer to the particular industry standard identified in the SPCC Plan to determine the scope of inspection and testing requirements. For example, under the STI SP001 standard, visual inspection is allowed for portable containers such as drums and totes. A baseline determination of metal thickness of a portable container is not required prior to implementing the visual-only integrity testing inspection protocol.

This section provides guidance on integrity testing for circumstances the EPA inspector may encounter at an SPCC-regulated facility, i.e., aboveground bulk storage containers for which the baseline condition is known and aboveground bulk storage containers for which the baseline condition is *not* known.

7.4.1 Aboveground Bulk Storage Container for Which the Baseline Condition Is Known

In the case of tanks for which the baseline condition is known (e.g., the shell thickness and bottom thickness), the inspection, evaluation and testing schedule should occur at a scope and frequency based on industry standards (or a hybrid inspection program developed by a PE, as described in *Section 7.5.3*) per §112.8(c)(6) or §112.12(c)(6). There is an advantage to knowing the baseline condition of a tank, particularly the remaining wall thickness and bottom thickness. Only when the baseline is known can an inspection and testing program be established on a regular schedule. The inspection interval should be identified consistent with intervals specified in industry standards or should be based on the corrosion rate and expected remaining life of the container. This inspection interval must be documented in the Plan in accordance with §§112.3(d), 112.7(e), 112.8(c)(6), and 112.12(c)(6). API 653 is an example of an industry standard that directs the owner/operator to consider the remaining wall thickness and bottom thickness, and the established corrosion rates to determine an inspection interval for external and internal inspections and testing. In the case of a tank that is newly built, construction data (e.g., as-built drawings and/or manufacturers cut-sheets) may typically be used as an initial datum to establish wall and bottom thicknesses, and would be included in the established procedures for inspection and testing.

Inspection and testing standards may require visual inspection of both the exterior and interior of the container, and the use of another method of non-destructive evaluation depending on the type and configuration of the container. EPA inspectors should note that the scope and frequency of inspections and tests for shop-built tanks and field-erected tanks at an SPCC-regulated facility may vary due to the age of the tank, the configuration, and the applicable industry standard used as the reference. For example, the Plan preparer may choose to develop an inspection and testing program for the facility's shop-built containers in accordance with STI SP001, and may elect to develop a program for the facility's field-erected containers in accordance with API 653. As an alternative example, the Plan preparer may elect to develop a program in accordance with STI SP001 for both the facility's shop-built and field-erected containers, after determining that the containers are within the scope of the standard.

7.4.2 Aboveground Bulk Storage Container for Which the Baseline Condition Is Not Known

For a facility to comply with the requirement for integrity testing of containers on a regular schedule (§§112.8(c)(6) and 112.12(c)(6)), a baseline condition for each container is necessary to establish inspection intervals. However, for shop-built and field-erected containers for which construction history and wall and/or bottom plate thickness baselines *are not known,* it is not possible to establish a regular integrity testing program at the time the Plan is prepared. In this case, the Plan preparer must describe in the SPCC Plan an interim schedule (in accordance with the introductory paragraph of §112.7) that allows the facility to gather the baseline data to establish a regular schedule of integrity testing in accordance with §§112.8(c)(6) and 112.12(c)(6).

When a container has no prior inspection history or baseline information, the implementation of the baseline inspection program is important in order to assess the container's "suitability for continued service." Both API 653 and STI SP001 contain minimum requirements to inspect aboveground containers and criteria to

assess a container's suitability for continued service. In some cases, where baseline information is not known, the testing program may include two data collection periods, one to establish a baseline of the container's existing shell and bottom plate thickness, and a second inspection to establish corrosion rates in order to develop the next inspection interval. These inspection intervals establish the frequency of the 'regular schedule' required for testing under the SPCC rule.

When no or only partial baseline information is available for a container at the facility, then the owner/operator should schedule integrity testing in accordance with industry standards as soon as possible and in accordance with both good engineering practice and the judgment of the certifying PE.[140] Because the SPCC Plan must be reviewed at the facility every five years in accordance with §112.5(b), the owner or operator of the facility should consider to begin collecting inspection data during the next five year period. As an example, a facility owner/operator is scheduling upcoming inspections for bulk storage containers at a facility he recently purchased. The owner/operator has no records of inspections or information on the in-service date (i.e. original construction date) for a 10,000-gallon aboveground storage container at the facility. The SPCC Plan was last amended on November 10, 2011. Therefore, in order to establish a baseline for the 10,000-gallon AST, the facility owner schedules the first (baseline) container inspection or integrity test by November 10, 2016.

Example baselining plans are presented in *Figure 7-1* and *Figure 7-2*. The examples present simple scenarios and are only provided as an illustration of some of the factors that may be considered when determining a schedule to initiate inspections of bulk storage containers.

[140] If the owner or operator of a Tier II qualified facility is not familiar with inspection standards, then he should consult with a tank inspection professional or PE to establish an inspection schedule.

Figure 7-1: Example baselining plan to determine the integrity testing and inspection schedule using API 653.

Scenario: A facility has three aboveground atmospheric, mild-carbon steel tanks of different ages and conditions. One has a prior inspection history; the others have never been inspected. Although there is limited history available regarding tank construction, the tanks are presumed to be field-erected tanks and to each have 100,000 gallons in storage capacity. The SPCC Plan was amended on November 10, 2011 and API 653 is the referenced inspection standard. What is an appropriate inspection schedule for these tanks?

Additional information: API 653 recommends a formal visual inspection* every 5 years or ¼ of corrosion rate, whichever is less, and a non-destructive shell test (UT) within 15 years or ½ of corrosion rate, whichever is less. If corrosion rates are not known, the maximum interval for a UT inspection is 5 years. For internal inspection, the interval from initial service to the initial inspection shall not exceed 10 years, or longer if certain tank safeguards are in place. Subsequent internal inspection intervals are based on corrosion rate shall not exceed 20 years for tanks without a release prevention barrier and 30 years for tanks with a release prevention barrier or at an inspection interval determined using risk-based inspection assessment. If the construction date and date of last inspection are unknown, the compliance date of the regulation should determine the starting point for an integrity testing schedule. The first inspection must occur within 5 years of the compliance date or a lesser period of time as determined by a PE in cases where there is higher risk.

Determination of inspection schedule:

	Construction Date	Last External and Internal Inspection	Next Inspection (External)	Next Inspection (Internal)
Tank 1	unknown	none	formal visual and shell test (external) before November 10, 2016	formal (internal) bottom inspection before November 10, 2016
Tank 2	2008	none	**2013** for both visual inspection and non-destructive shell test**	**2018** or longer if cathodic protection or other safeguards are in place
Tank 3	1984	**Last External:** Inspections conducted in 1999, 2004, and 2009 **Last Internal:** 1999	**2014** for formal visual** **2014** non-destructive shell test. Both intervals may be decreased based on calculated corrosion rates from the 1999 inspection.	**2029** if the tank has a release prevention barrier, **2019** if the tank does not have a release prevention barrier or sooner based on corrosion rates from the 1999 inspection or as determined from risk-based inspection assessment

* A formal visual inspection is one conducted by a certified inspector.

** Inspection should be conducted as soon as possible and in consultation with a PE.

Note: Actual inspection schedule is ultimately an engineering determination made by the PE, based on industry standards, and is certified in the Plan. Other events or factors that occur during the life of the container could cause the owner/operator to revise the inspection interval originally calculated.

Figure 7-2: Example baselining plan to determine the integrity testing and inspection schedule using STI SP001.

Scenario: A facility has four aboveground atmospheric, mild-carbon steel tanks of different ages and conditions. One has a prior inspection history; the others have never been inspected. The tanks are shop-fabricated. Tanks 1, 2 and 3 have 40,000 gallons in storage capacity and Tank 4 has 10,000 gallons in capacity. The SPCC Plan was amended on November 10, 2011 and STI SP001 is the referenced inspection standard. What is an appropriate inspection schedule for these tanks?

Additional information: Tanks 1, 2 and 3 are in Category 3 of STI SP001 (i.e., do not have spill control or a continuous release detection method, or CRDM). In addition to periodic inspections recommended by the standard for all tanks, for tanks in Category 3 STI SP001 recommends that a formal external inspection,* as well as a leak test by owner be conducted at a maximum of 5-year intervals, and that a formal internal inspection* be conducted at 10-year intervals. Tank 4 is in Category 1 of STI SP001 (i.e., has spill control and CRDM). For this tank, STI SP001 recommends that a formal external inspection be conducted by a certified inspector at a maximum of 20-year intervals. No formal internal inspection or leak test is required.

If the construction date and date of last inspection are unknown, the compliance date of the regulation should determine the starting point for an integrity testing schedule. The first inspection must occur within 5 years of the compliance date or a lesser period of time as determined by a PE in cases where there is higher risk.

Determination of inspection schedule:

	Construction Date (in service date)	Last External and Internal Inspection	Next Inspection (External)	Next Inspection (Internal)
Tank 1	unknown	none	Formal external inspection and leak testing before November 10, 2016	Formal internal inspection before November 10, 2016
Tank 2	2004	none	**2009** for formal external inspection and leak testing**	**2014** for formal internal inspection
Tank 3	1984	2005	**2010** for formal external inspection and leak testing**	**2015** for formal internal inspection*
Tank 4	2002	none	**2022** for formal external inspection	Not required

* A formal inspection is one conducted by a certified inspector.

**Inspection should be conducted as soon as possible and in consultation with a PE.

Note: Actual inspection schedule is ultimately an engineering determination made by the PE, based on industry standards, and is certified in the Plan. Other events or factors that occur during the life of the container could cause the owner/operator to revise the inspection interval originally calculated.

7.5 Specific Circumstances

Integrity testing in accordance with industry standards is required for all aboveground bulk storage containers located at onshore facilities (except oil production facilities), unless the facility owner/operator implements an environmentally equivalent method according to §112.7(a)(2) and documents the deviation in

the SPCC Plan (see *Chapter 3: Environmental Equivalence*). This section provides guidance on integrity testing for the following circumstances that an EPA inspector may encounter at an SPCC-regulated facility:

- Integrity testing scenarios for shop-built containers; and
- Using environmentally equivalent alternatives for integrity testing.

This is not a comprehensive list of circumstances. For these and other cases, a PE may recommend alternative approaches.

7.5.1 Integrity Testing Scenarios for Shop-built Containers

Scenario 1: Mobile or Portable Bulk Storage Containers

Industry standards (such as STI SP001) refer to specific conditions for which visual inspection alone is an appropriate method for verifying the integrity of certain smaller shop-built containers (e.g., portable containers such as drums and totes). These conditions include container type, size, and configuration (such as whether the container is in contact with the ground or has appropriate secondary containment). For example, according to STI SP001, when portable containers have adequate secondary containment then visual inspection of these containers is acceptable and will satisfy the integrity testing requirements of the rule at §112.8(c)(6).

Scenario 2: Single-Use Mobile or Portable Containers.

For containers that are single-use and for dispensing only (i.e., the container is not refilled), industry standards such as STI SP001 may require only visual examination by the owner/operator. Since these containers are single-use, other types of integrity testing such as internal or comparative integrity testing for corrosion are generally not appropriate because the containers are not maintained on-site for a long enough period of time that degradation and deterioration of the container's integrity might occur. Single-use containers (e.g., 55-gallon drums) typically are returned to the vendor, recycled, or disposed of in accordance with applicable regulations. Good engineering practices for single-use containers should be identified in the Plan, and these practices should follow industry standards and ensure that the conditions of storage or use of a container do not subject it to potential corrosion or other conditions that may compromise its integrity in its single-use lifetime.

Scenario 3: Elevated large shop-built containers.

The SPCC rule requires that inspections be in accordance with industry standards. Under certain circumstances the standards may stipulate that visual inspection alone will suffice. However, for tanks larger than 5,000 gallons, most industry standards require more than a visual inspection by the owner or operator.

The previous version of this Guidance[141] published in 2005 described an example considered environmentally equivalent to the integrity testing requirements of the SPCC rule at that time. The example described visual inspection plus certain additional actions to ensure the containment and detection of leaks as appropriate for bulk oil storage containers with a capacity up to 30,000 gallons. This example was based on a policy that described the environmental equivalence flexibility available to a PE with respect to integrity testing in a letter to the Petroleum Marketers Association of America (PMAA).[142]

Figure 7-3: Shop-built containers elevated on saddles.

This example was established at a time when the rule specifically required that integrity testing include more than just a visual inspection. While the approach for the use of environmental equivalence described in this letter is still valid, EPA revised the integrity testing provision in 2008 to allow inspection requirements outlined in industry standards to be used without the need for environmental equivalence determinations certified by a PE. After EPA wrote the letter to PMAA in 2004, a major industry standard for integrity testing (STI SP001) was modified to outline ''good engineering practice'' for integrity testing of shop-built containers. This may affect a PE's decision whether to certify an environmentally equivalent approach as described in the PMAA letter, or to follow an applicable industry standard without having to certify the measures described in the PMAA letter as an environmentally equivalent method of integrity testing.

If an owner or operator deviates from applicable industry standards to develop an integrity testing program, then a PE must certify an environmentally equivalent alternative in the SPCC Plan. The Plan must provide the reason for the deviation, describe the alternative approach, and explain how it achieves environmental protection equivalent to the applicable industry standard.

Scenario 4: Shop-built containers placed on a liner.

Certain industry standards, such as STI SP001, also specify differentiated inspection practices for certain shop-built containers that are placed on a barrier or liner and where this barrier is designed in a way that ensures that any leaks are immediately detected. The size of the container and other site-specific factors determine appropriate inspection or testing procedures and frequencies.

Scenario 5: Double-walled tanks or containers

A double-walled tank is essentially a tank within another tank, equipped with an interstitial (i.e., annular) space and constructed in accordance with industry standards. The inner tank serves as the primary oil storage container while the outer tank serves as secondary containment. The outer tank of a double-walled tank

141 *SPCC Guidance for Regional Inspectors*, Version 1.0, November 28, 2005.

142 Letter to Daniel Gilligan, President, Petroleum Marketers Association of America, from Marianne Lamont Horinko, Assistant Administrator, Office of Solid Waste and Emergency Response, EPA, May 25, 2004 (available in *Appendix H* of this document).

may provide adequate secondary containment for discharges resulting from leaks or ruptures of the entire capacity of the inner storage tank.

Section 112.8(c)(6) requires the owner or operator to conduct integrity testing on a regular schedule and whenever he makes repairs. One possible advantage of a double-walled shop fabricated aboveground tank is that industry standards (such as STI SP001[143]) may specify a less stringent program for integrity testing during the life of the container. However, note that industry standards may specify more stringent integrity testing requirements for double-walled tanks not equipped with an interstitial space (e.g., formal non-destructive testing).

Section 112.8(c)(6) also requires that the owner or operator frequently inspect the outside of the container for signs of deterioration, discharges, or accumulation of oil inside diked areas (for a double-walled tank, this inspection requirement applies to the inner tank). To comply with the requirement to frequently inspect the outside of the tank, an owner or operator must inspect the interstitial spaces of a shop-built double-wall AST. Typically this is accomplished by an inspection port (which can be visually inspected or used in conjunction with a dip stick, camera, or visual leak indicator), a drain plug, sensors or other equivalent means to detect a discharge into the interstitial (annular) space from the inner primary container. EPA recommends the use of automatic detection devices to detect discharges into the interstitial space. Once a discharge is discovered in the interstice, corrective action is typically required by industry standards. After a discharge to the interstitial space has occurred, the system is no longer operating as a double-walled tank (because the external tank is serving as the primary container unless and until appropriate repairs are made in accordance with the applicable industry standard).

Owners or operators should conduct integrity testing and inspections in accordance with industry standards, when applicable. One industry standard to consider is "SP001, Standard for Inspection of In-Service Shop-Fabricated Aboveground Tanks for Storage of Combustible and Flammable Liquids."

For more information on secondary containment requirements for double-walled tanks see *Chapter 4: Secondary Containment and Impracticability, Section 4.4.5.*

7.5.2 Integrity Testing and Inspection Requirements for Bulk Storage Containers at Onshore Facilities – Environmental Equivalence

In December 2008, EPA amended the requirements at §§112.8(c)(6) and 112.12(c)(6) to provide flexibility in complying with the bulk storage container integrity testing requirements. EPA modified the provision to allow an owner or operator to consult and rely on industry standards to determine the appropriate qualifications for personnel performing tests and inspections, as well as the type and frequency of integrity testing required for a particular container size and configuration.

The integrity testing requirements are subject to the environmental equivalence provision, but given the increased flexibility, there may be few, if any, instances where a PE would determine that a deviation is

[143] SP001 Standard for the Inspection of Aboveground Storage Tanks, 5th Edition, Issued September 2011.

appropriate. This is because the rule allows inspection requirements outlined in industry standards to be used without the need for environmental equivalence determinations certified by a PE (see 73 FR 74265, December 5, 2008).

As with other requirements eligible for environmental equivalence provision, a facility owner or operator may not rely solely on measures that are required by other sections of the rule (e.g., secondary containment) to provide "equivalent environmental protection" for integrity testing required under §112.8(c)(6) or §112.12(c)(6). Otherwise, the deviation provision would allow for approaches that provide a lesser degree of protection overall.

In any case where the owner or operator of a facility uses an alternative means of meeting the integrity testing requirement of §112.8(c)(6) or §112.12(c)(6), the SPCC Plan must provide the reason for the deviation, describe the alternative approach, which is most likely to be a site-specific inspection program (i.e., hybrid inspection program), and explain how it achieves equivalent environmental protection (§112.7(a)(2)), while considering good engineering practice and industry standards. In cases where industry standards apply to a container, the PE would need to explain how an inspection or test that deviates from an applicable industry standard is environmentally equivalent to following established industry standards and how it will be implemented in the field. This determination is site-specific and based on good engineering practice as determined by the certifying PE. The hybrid inspection program should include the recommended minimal elements described in *Section 7.5.3* for a PE-developed site-specific integrity testing program. *Figure 7-4* provides a summary of integrity testing and inspection program documentation for bulk storage containers at onshore facilities, by type of SPCC Plan and standard applicability case.

The following sections describe situations in which a hybrid inspection program is developed to comply with the bulk storage container inspection requirements of §§112.8(c)(6) and 112.12(c)(6).

Hybrid Inspection Program Rather than an Applicable Industry Standard

Although the rule requires that the Plan preparer consider industry standards when developing an inspection program, the SPCC Plan can include an environmentally equivalent (i.e., hybrid) inspection program when the owner or operator and the certifying PE determine that another inspection approach would be more appropriate or cost effective, based on site-specific factors. The SPCC Plan must include the reason for deviating from the rule requirements, and describe the alternative method in detail, including how it is environmentally equivalent.

An environmentally equivalent approach to following the applicable industry standard verbatim may be a hybrid inspection program that is based on elements designed to minimize the risk of container failure and allow detection of leaks before they impact navigable waters or adjoining shorelines. These elements may be based on a combination of various industry standards and good engineering practice and should include the recommended minimal elements described in *Section 7.5.3* for a PE-developed site-specific integrity testing program (or hybrid inspection program). Alternative measures may, for example, prevent container failure by minimizing the container's exposure to conditions that promote corrosion (e.g., direct contact with soil), or they may enable facility personnel to detect leaks and other container integrity problems early so these problems can

be addressed before more severe integrity failure occurs. The ability to use an environmentally equivalent alternative to integrity testing in accordance with an applicable industry standard may be influenced by the tank configuration and adequacy of secondary containment. The facility owner/operator may determine that alternatives to inspection frequency and type of testing and inspections may be more appropriate according to site-specific conditions.

If a Tier II qualified facility owner or operator chooses to develop an alternative inspection program rather than follow an applicable industry standard, then he must have a PE certify the environmentally equivalent measures as described in §112.6(b)(4). A Tier I qualified facility owner or operator cannot deviate from applicable industry standards when following the requirements for Tier I qualified facilities in §112.6(a).

Hybrid Inspection Program that Deviates from a Portion of an Industry Standard

It may be appropriate to deviate from portions of an industry standard under certain circumstances. Although the Plan preparer must determine, in accordance with industry standards, the appropriate qualifications for personnel performing tests and inspections, and the frequency and type of testing and inspections when developing the inspection and/or testing program, the inspection program can deviate from a portion of a standard when another approach would be more appropriate or cost effective, based on site-specific factors. The SPCC Plan must document the environmentally equivalent alternative, the reason for deviating from the rule requirement, and describe the alternative method in detail, including how it is environmentally equivalent.[144] The PE should document in the Plan what industry standard applies, how the hybrid inspection program deviates from the applicable industry standard, and how the inspection program meets the minimal recommended elements described in *Section 7.5.3*.

If a Tier II qualified facility owner or operator chooses to deviate from a portion of an applicable industry standard, then he must have a PE certify the environmentally equivalent measures as described in §112.6(b)(4). A Tier I qualified facility owner or operator cannot deviate from applicable industry standards when following the requirements for Tier I qualified facilities in §112.6(a).

No Applicable Industry Standard

Industry standards are often developed to address a particular industry sector or type of container or equipment. The scope of a standard may limit how it should be applied by specifying the type of containers or equipment, their service conditions, the specific gravity of stored products, or other factors. Two commonly used steel tank inspection standards are STI SP001[145] and API 653.[146] The scope of these two standards addresses many of the steel storage tanks in service at SPCC-regulated facilities and it is likely that one of these inspection standards can be applied. However, if in the judgment of a PE or qualified facility owner/operator, no industry standard applies to a particular container, then the Plan preparer should consider the manufacturer's

---

144 See 73 FR 74264 (December 5, 2008)

145 STI Standard SP-001, "Standard for the Inspection of Aboveground Storage Tanks," 5th Edition September 2011.

146 API Standard 653, "Tank Inspection, Repair, Alteration, and Reconstruction," Fourth Edition, American Petroleum Institute, April 2009 Addendum 2 January 2012.

specifications and instructions for the proper use and maintenance of the equipment, appurtenance, or container. If no industry standards or manufacturer's instructions apply, the Plan preparer may also call upon his/her professional experience and/or consult with tank inspection professionals to develop site-specific inspection and testing requirements for the facility or equipment that are in accordance with good engineering practice and document them in the Plan.

A customized, site-specific inspection program (i.e., hybrid inspection program) should be based on relevant industry standards (in whole or in part) and other good engineering principles. The hybrid inspection program should be designed to measure the structural soundness of a container shell, bottom, and/or floor to contain oil, and may include leak testing to determine whether the container will discharge oil. API 653 and STI SP001 provide the foundation for integrity testing and inspecting containers, and in many cases it may still be appropriate to consider these standards when developing a hybrid inspection program.

A PE does not need to provide and certify an environmental equivalence justification for implementing a hybrid inspection program when industry standards do not apply to a container or the container is outside the scope of the standard. However, the PE attests in the Plan certification that required inspections and testing have been established and that the Plan has been prepared in accordance with good engineering practice, including applicable industry standards. The PE should document in the Plan why current industry standards do not apply and how the hybrid inspection program meets the minimal recommended elements described in *Section 7.5.3*.

Tip – AFVO containers and tanks operated at elevated temperatures

Although existing industry standards are not specific to integrity testing of AFVO bulk storage containers or tanks operated at elevated temperatures (e.g. asphalt), facilities with these storage containers can follow API Standard 653, "Tank Inspection, Repair, Alteration, and Reconstruction" because the scope is written broadly to include any steel tank constructed in accordance with a tank specification.

The Plan must describe the procedures for this inspection program and the facility owner or operator must keep a record of inspections and tests for three years. Industry standards often advise that records for formal inspections and tests be maintained for the life of the container. These records can be helpful to inform changes in the inspection program.

It is unlikely that qualified facility owner/operators will have bulk storage containers for which no industry standard applies. However, if a qualified facility owner or operator determines that no industry standard applies, then he should follow the procedures described above to develop an inspection program for bulk storage containers. No environmental equivalence determination is necessary in this case and a PE does not need to certify the hybrid inspection program. However, a qualified facility owner/ operator who develops a hybrid inspection program should consider consulting with a tank inspection professional or a PE. The qualified facility owner/operator should also clearly explain why current industry standards do not apply and how the hybrid inspection program meets the minimal recommended elements described in *Section 7.5.3*.

AFVO Bulk Storage Containers

The inspection and/or testing requirements for AFVO at §112.12(c)(6)(i) are identical to those described at §112.8(c)(6). The SPCC rule also provides differentiated, more flexible, alternative inspection requirements at

§112.12(c)(6)(ii) for AFVO containers that meet certain criteria (see *Section 7.2.4*). A facility owner/operator with AFVO bulk storage containers may follow an applicable industry standard, such as API 653, to conduct inspections in accordance with the requirements of §112.12(c)(6)(i), follow the requirements of §112.12(c)(6)(ii) (if applicable), or provide an environmentally equivalent measure in the SPCC Plan in accordance with §112.7(a)(2) of the SPCC rule.

The facility owner or operator has flexibility to make an environmental equivalence determination, in accordance with §112.7(a)(2), to address those bulk storage containers that have alternative configurations and meet the intent of the criteria in §112.12(c)(6)(ii) to minimize internal and external corrosion of the container and allow personnel to visually identify a discharge. For example, the criteria in §112.12(c)(6)(ii) requires that bulk storage containers be subject to 21 CFR part 110. However, bulk storage containers that store food oil and are built according to industry standards (such as 3–A Sanitary Standards) may have additional design features to minimize internal and external corrosion of the container and allow for visual detection of a discharge that provide equivalent environmental protection to 21 CFR part 110. Container configurations built according to 3–A Sanitary Standards typically include "manholes" that facilitate complete access for examination of the entire internal surface. These containers also typically have an outer shell (i.e., a double wall) that is sealed completely such as with completely welded seams so that the container integrity is maintained because insulation is less likely to be exposed to moisture.

If a hybrid inspection program is used to meet the integrity testing requirements in §112.12(c)(6), the Plan must state the reasons for nonconformance and explain how the hybrid inspection program provides equivalent environmental protection. The Plan should also address how the program effectively minimizes the risk of container failure and allows detection of leaks before they become significant.

A PE must review and certify the environmental equivalence determination. If a PE develops a hybrid inspection program for a facility, rather than uses an applicable industry standard, then the PE must describe why the hybrid inspection program does not follow the applicable industry consensus standard and how the hybrid inspection program is environmentally equivalent to the industry standard and meets the minimal recommended elements described in *Section 7.5.3*.

7.5.3 Suggested Minimum Elements for a PE-Developed Site-Specific Integrity Testing Program (Hybrid Inspection Program)

Although EPA requires inspection, evaluation, and testing in accordance with industry standards, it does not require that inspections and tests be performed according to a specific standard. Consistent with the environmental equivalence provision in §112.7(a)(2), the PE may use industry standards along with other good engineering practices to develop a customized inspection and testing program for the facility (a "hybrid" inspection program), considering the equipment type and condition, characteristics of products stored and handled at the facility, and other site-specific factors. The PE may also develop a hybrid program in the rare cases where industry standards do not apply to a container. The hybrid program should be designed to measure the structural soundness of a container shell, bottom, and/or floor to contain oil, and may include leak testing to determine whether the container will discharge oil. The components of a hybrid inspection program would likely include frequent visual inspections by the owner as well as periodic formal inspections (plus integrity testing, as

appropriate) by a certified inspector. Alternatively, the PE can recommend an inspection program following a specific standard, even when the standard does not specifically identify the container in its scope, if he believes that the inspection elements of that standard are appropriate for the container(s) at the facility and in accordance with good engineering practices.

Any hybrid inspection program should include an evaluation of the principal elements that would cause a tank to fail, and how the inspection program addresses finding such conditions, or prevents such conditions from continuing to the point of failure. For example, internal and external corrosion conditions must be considered, and a testing method developed to assure that the condition is identified and measured. Conditions that may lead to a structural failure, for example a failing foundation, should be identified and evaluation methods developed to identify the condition. In all cases, careful consideration should be given to discovering such conditions that may not be identifiable from visual examination, such as the bottom of floor plates. Hybrid programs should also include evaluation of container modifications made since last examination that may degrade integrity or lead to failure.

The following is a partial list of items to consider regarding the elements of a hybrid inspection program.

1) For shop-built tanks:

- Visually inspect exterior of tank;
- Evaluate external pitting;
- Evaluate hoop stress and longitudinal stress risks where corrosion of the shell is present;
- Evaluate condition and operation of appurtenances;
- Evaluate welds;
- Establish corrosion rates and determine the inspection interval and suitability for continued service;
- Evaluate tank bottom where it is in contact with ground and no cathodic protection is provided;
- Evaluate the structural integrity of the foundation;
- Evaluate anchor bolts in areas where required; and
- Evaluate the tank to determine whether it is hydraulically sound and not leaking.

2) For field-erected tanks:

- Evaluate foundation;
- Evaluate settlement;

- Determine safe product fill height;
- Determine shell corrosion rate and remaining life;
- Determine bottom corrosion rate and remaining life;
- Determine the inspection interval and suitability for continued service;
- Evaluate welds;
- Evaluate coatings and linings;
- Evaluate repairs for risk of brittle fracture; and
- Evaluate the tank to determine whether it is hydraulically sound and not leaking.

EPA suggests that an appropriately trained and qualified inspector conduct a hybrid inspection and provide a detailed report of the findings. The qualifications of the tank inspector will depend on the condition and circumstances of the tank (e.g., size, field-erected or shop-built), and a tank inspector should only conduct an inspection to the extent he/she is qualified to do so. A registered PE may be able to perform the hybrid inspection or could have a certified tank inspector (e.g., STI or API) complete the inspection.[147] Either way, the hybrid inspection program should be reviewed and certified by a PE in accordance with §112.3(d) (or §112.6(b)(4) for Tier II qualified facilities).

EPA inspectors may review checklists that are used by facility personnel to conduct the frequent inspections. *Table 7-4* provides an example of the type of information that may be included on an owner/operator-performed inspection checklist.

[147] Note that industry inspection standards require the inspector's certification number on these reports.

Table 7-4: Owner/Operator tank inspection checklist (from Appendix F of 40 CFR part 112).

I.	Check tanks for leaks, specifically looking for:	
	A.	Drip marks;
	B.	Discoloration of tanks;
	C.	Puddles containing spilled or leaked material;
	D.	Corrosion;
	E.	Cracks; and
	F.	Localized dead vegetation.
II.	Check foundation for:	
	A.	Cracks;
	B.	Discoloration;
	C.	Puddles containing spilled or leaked material;
	D.	Settling;
	E.	Gaps between tank and foundation; and
	F.	Damage caused by vegetation roots.
III.	Check piping for:	
	A.	Droplets of stored material;
	B.	Discoloration;
	C.	Corrosion;
	D.	Bowing of pipe between supports;
	E.	Evidence of stored material seepage from valves or seals; and
	F.	Localized dead vegetation.

7.6 Documentation Requirements and Role of the EPA Inspector

When evaluating the SPCC Plan the EPA inspector will need to review the scope of the inspection program identified in the Plan and determine whether the facility owner/operator is implementing the program as described. Additionally, if there have been any changes or alterations to bulk storage containers at the facility, the EPA inspector will need to identify whether those alterations were performed in accordance with industry standards and whether additional evaluations were conducted and documented.

7.6.1 Evaluating Tank Re-Rating Alterations

Chapter 2: SPCC Rule Applicability, Section 2.7.3 describes how to calculate the storage capacity for bulk storage containers and discusses appropriate methods for altering the capacity of a bulk storage container (i.e., tank re-rating). Re-rating a tank's storage capacity is permitted when the alteration is completed in accordance with applicable industry standards and good engineering practice. As discussed in Chapter 2: SPCC Rule Applicability, Section 2.7.3, any container alteration will require a technical amendment to the SPCC Plan certified by a PE in accordance with §112.5. Additionally, tank alterations which change the original shell capacity may affect secondary containment capacity necessary to comply with SPCC requirements and FRP applicability and requirements under 40 CFR part 112 subpart D. Any subsequent changes to the shell capacity (e.g., to increase capacity) will require a re-assessment of SPCC compliance and FRP applicability.

Since this type of alteration may have a significant impact on secondary containment capacity, compliance with SPCC rule requirements, and FRP applicability, the EPA inspector must carefully review these alterations. This review should consider relevant SPCC requirements and Plan documentation, industry standards, records, and field observations as described below.

Relevant SPCC Requirements and Plan Documentation:

The EPA inspector should consider the following questions when evaluating whether the SPCC Plan appropriately addresses tank alterations completed at the facility:

- Do all relevant sections of the SPCC Plan reflect the current container capacity and was the technical amendment to the Plan documented and certified by a PE?
  - The certifying PE must sign an amendment to the SPCC Plan. As part of this certification, the PE verifies that the modifications to the tank (e.g., installation of overflow ports or new tank bottom) were done in accordance with industry standards and identifies the standard used (e.g., API 653).
- Have operating procedures that may be affected by the alteration been updated in the Plan to reflect the current tank capacity?
- If the alteration includes an overflow nozzle and the associated overflow pipe is equipped with a valve,[148] does the Plan clearly explain the purpose of the valve and identify the reasons the valve may be closed, including any implications for 40 CFR part 112 requirements when the valve is closed and the capacity of the tank reverts to a larger capacity? Each time the valve is closed, was a technical amendment of the SPCC Plan completed to address:
  - Revised tank capacity;
  - Adequacy of secondary containment capacity; and

[148] A valve is not recommended unless otherwise required by code.

- Updates to tank transfer procedures (to identify change in maximum capacity of the tank), facility diagram, tank information and any other relevant SPCC requirements.

- Additionally, has the facility owner/operator determined FRP applicability based on tank capacity when the valve is both open and closed? If the facility is FRP-subject when the valve is closed then was an FRP submitted to the EPA regional office?

Relevant Industry Standards:

API Standard 650, *Welded Tanks for Oil Storage*,[149] and API Standard 653, *Tank Inspection, Repair, Alteration, and Reconstruction,*[150] include specifications for tank construction and inspections (respectively) that are relevant when re-rating a tank. When evaluating a tank that has been re-rated to a lower storage capacity, the EPA inspector should verify that the documentation of the tank alterations describe conformance with industry standards, which stipulate the following:[151]

API 650 Specifications:

- When emergency overflow slots are used, the overflow slots are covered with a corrosion-resistant coarse-mesh screen and provided with weather shields (the closed area of the screen must be deducted to determine the net open area).

- The overflow slots are sized to discharge at the pump-in rates for the tank. Overflow discharge rates were determined by using the net open area (less screen) and using a product level (for determining head pressure) not exceeding the top of the overflow opening.

- The floating-roof seal does not interfere with the operation of the emergency overflow openings.

- Overflow slots are not placed over the stairway or nozzles unless restricted by tank diameter/height or unless overflow piping, collection headers, or troughs are specified by the Purchaser [e.g., facility owner/operator] to divert flow.

API 653 Specifications:

API 653 provides requirements on installing new penetrations (such as a nozzle) in existing tanks. The standard requires:

---

149 API Standard 650, "Welded Tanks for Oil Storage," Eleventh Edition, American Petroleum Institute, June 2007 Addendum 3 August 2011, Errata, October 2011.

150 API Standard 653, "Tank Inspection, Repair, Alteration, and Reconstruction," Fourth Edition, American Petroleum Institute, April 2009 Addendum 2 January 2012.

151 Please note that these are summaries. EPA inspectors should refer to the full text of the relevant industry standards when conducting an evaluation of a tank alteration.

- All design, work execution, materials, welding procedures, examination, and testing methods be approved by the authorized inspector or by an engineer experienced in storage tank design.
- New shell penetrations (i.e. nozzles) be in accordance with material, design, and stress relief requirements of API 650, and in accordance with relevant portions of API 653.
- Proper spacing of welds.
- Examinations be performed in accordance with the standard:
  - Penetrations (i.e. nozzles) located on a shell joint must receive additional shell radiography in accordance with API 650.
  - Nozzle neck to shell welds and reinforcing plate to shell and nozzle neck welds must be examined by magnetic particle or liquid penetrant examination.
- When penetrations are installed using insert plates as described in the standard, the completed butt welds between the insert plate and the shell plate must be fully radiographed.
- If the shell course where the nozzle is installed is thicker than ½ inch and shell material does not meet current API 650 and API 653 design metal temperature the overflow nozzle must be installed with an insert plate.

Records:

When an EPA inspector is evaluating a tank that has been re-rated to a lower storage capacity, the EPA inspector should request/review the following records:

- Documentation from a PE that the overflow port is sized based on filling the tank (i.e., fill rate) without substantially increasing the liquid level above the bottom of the overflow opening and is in accordance with API 653;
- Documentation in the owner/operator records on what modifications were made and when, and the maximum liquid level;
- Records that the overflow was inspected by an API 653 certified inspector or reviewed by a tank engineer;
- Documentation on materials, welding procedure, examinations, and testing methods; and
- Records required by the standards. API 653 requires that records of alterations be kept on file. When a tank is evaluated, repaired, altered, or reconstructed the following documentation is maintained in the owner/operators' tank records:
  - Calculations on the following:

  - Evaluation of the component for integrity, including brittle fracture considerations;
  - Re-rating (including liquid level); and
  - Repair and alteration considerations.

- Supporting Data (as applicable):

  - Inspections;
  - Material test report/certifications;
  - Tests;
  - Radiographs;
  - Brittle fracture considerations; and
  - Construction completion record.

EPA Inspector Field Observations:

When an EPA inspector is evaluating a tank in the field that has been re-rated to a lower storage capacity, the EPA inspector should look for the following:

- Is the overflow port away from shell welds? When the shell plate, where the nozzle is located, is less than or equal to ½ inch thick, the required spacing is 6 inches from vertical welds and 3 inches from horizontal welds. Other spacing is required for thicker shell plates.
- If the overflow port is a nozzle, the nozzle must have a reinforcing plate or be installed with a thickened insert plate.
- If the overflow nozzle has an overflow pipe, check that it is supported from the shell.
- Check to see if the overflow port's circumference appears proportional to the circumference of the piping supplying the tank with product.
- Does there appear to be a blank flange (skillet) installed between the nozzle and the overflow pipe or any flange along the overflow pipe? This could be difficult to view from ground level, but if a gap exists between the nozzle flange and the overflow pipe fitting or between two flanges along the piping, ask the owner/operator if the alteration has been modified.

The tank may have a new nameplate indicating what modifications were made, the date, and the maximum liquid level. NOTE: API 653 Section 13 covers requirements for nameplates for reconstructed tanks and tanks without nameplates, but does not specifically require the owner/operator to install a new nameplate for altered tanks.

7.6.2 Evaluating Inspection, Evaluation and Testing Programs

The facility SPCC Plan must describe the scope and schedule of testing and examinations to be performed on bulk storage containers (as required in §§112.3(d)(1)(iv), 112.7(e), 112.8(c)(6), 112.9(c)(3), and 112.12(c)(6)), and should reference an applicable industry inspection standard or describe an equivalent program (i.e., hybrid inspection program) developed by the PE, in accordance with good engineering practice. If an SPCC Plan specifies a hybrid inspection and testing program, then the EPA inspector should verify that the testing program covers minimum recommended elements for the inspections, the frequency of inspections, and their scope (e.g., wall thickness, footings, tank supports). In cases where the hybrid inspection and testing program is used in lieu of applicable industry standards, the EPA inspector should verify that the Plan includes an environmental equivalence determination, certified by a PE. See *Section 7.5.3* for a list of recommended minimum elements.

If an owner or operator has yet to implement the integrity testing program, the SPCC Plan should establish and document a schedule (in accordance with good engineering practice and the introductory paragraph of §112.7) that describes the projected implementation of the integrity testing program for the aboveground bulk storage containers at the facility. The EPA inspector should pay close attention to the scheduling of integrity testing to ensure that the facility is implementing any schedule associated with §112.7. The EPA inspector should also review the rationale for any inspection schedule that extends beyond the frequency identified in applicable inspection standards (particularly if no baseline exists for the tanks).

A hybrid testing program may be appropriate for a facility where an industry inspection standard does not yet contain enough specificity for a facility's particular tank(s) and/or configuration, or while modifications to an existing industry inspection standard are under consideration. For example, a tank user may have made a request to the industry standard-setting organizations recommending a change or modification to a standard. Both API and STI have mechanisms to allow tank users (and the regulatory community) to request changes to their respective inspection standards. In this case, the modification to a standard may be proposed, but not yet accepted by the standard-setting organization. In the meantime, the facility is still subject to the SPCC requirements to develop an inspection and testing program in accordance with industry standards. In this scenario, a hybrid inspection and testing program may be appropriate. When reviewing the scope and schedule of a hybrid program, the EPA inspector should ensure that a PE has attested that the program has been developed in accordance with good engineering practice and is being implemented at the facility.

The owner or operator of the facility must maintain records of all visual inspections and integrity testing, as required by the SPCC rule in §112.7(e). The owner or operator must keep written procedures and a record of the inspections and tests, signed by the appropriate supervisor or inspector, with the SPCC Plan for a period of three years.[152] Records do not need to be specifically created for this purpose, and may follow the format of records kept under usual and customary business practices, including electronic records. For example, it may be usual and customary to keep inspection records for a drum storage area rather than for each individual drum. These records should cover the frequent inspections performed by facility personnel. Also, industry standards

[152] Facility Response Plan holders are required to maintain inspection records for five years.

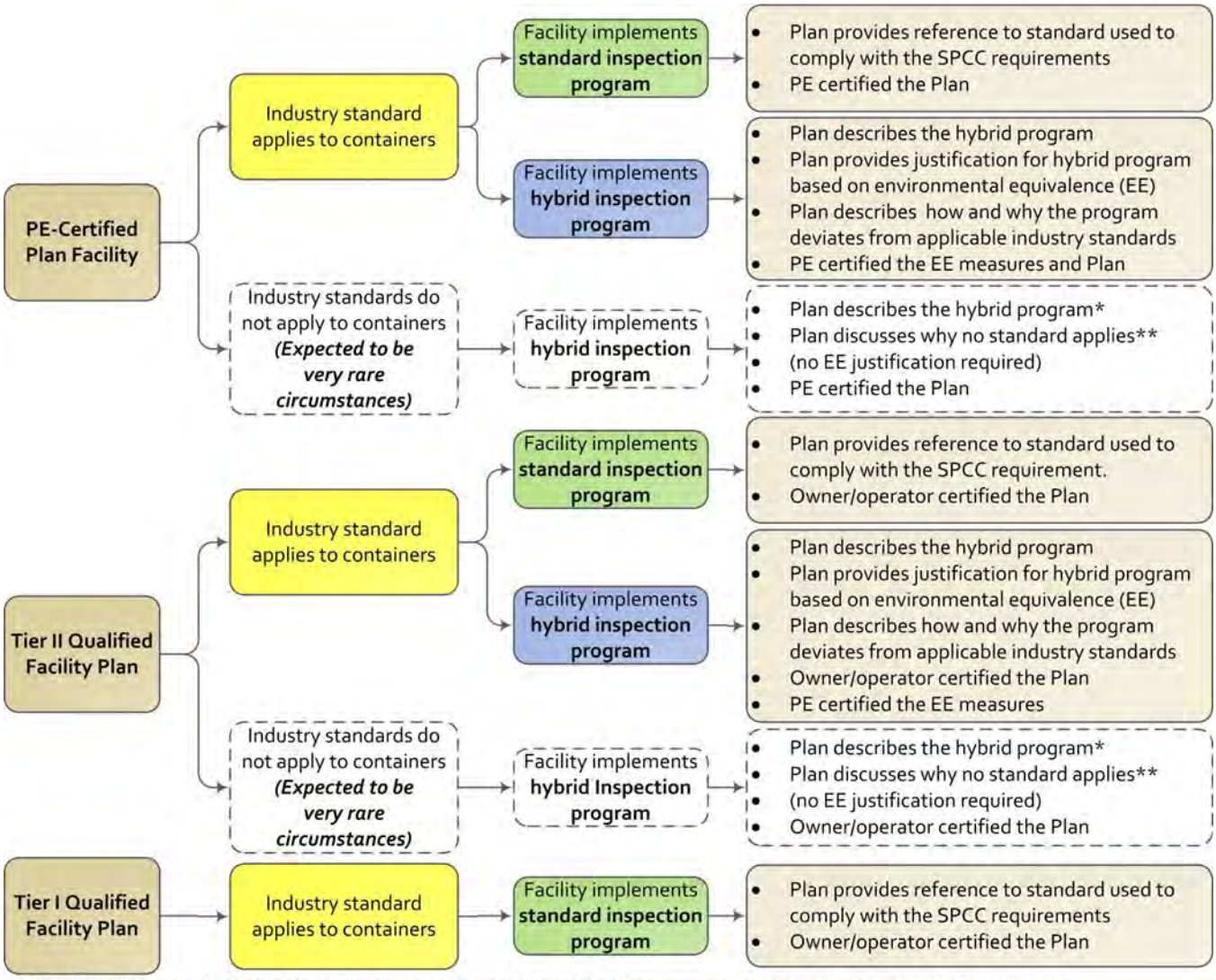
generally provide example guidelines for formal tank inspections, as well as sample checklists. The EPA inspector should review the inspection checklists used by the facility to verify that they are in accordance with the inspection and testing program as certified in the SPCC Plan. The tank inspection checklist from Appendix F of 40 CFR part 112, reproduced as *Table 7-4* in this chapter, provides an example of the type of information that may be included on an owner/operator-performed inspection checklist. Industry standards, such as STI SP001, also provide example inspection checklists.

The EPA inspector should review the description of the integrity testing/inspection program in the SPCC Plan and determine whether it follows an industry standard; deviates from applicable standards; or indicates that no industry standard applies to certain containers. If the program follows an industry standard, the EPA inspector should review the program to verify that it follows the applicable elements of the standard. If an inspection program deviates from industry standards, or the SPCC Plan indicates that no industry standard applies to a particular container, the EPA inspector should review the rationale described in the SPCC Plan and check that the alternative inspection program addresses the recommended minimal elements of a hybrid inspection program described in *Section 7.5.3*.

If an SPCC Plan contains measures that deviate from an applicable industry standard, based on environmental equivalence, then the EPA inspector should look for a clear rationale for the development of the inspection and testing program, paying close attention to the referenced industry standard. The Plan should address how the alternative approach complies or deviates from industry inspection standards and how it will be implemented in the field.

Figure 7-4 summarizes the type of documentation the EPA inspector should look for when reviewing the use of industry standards to meet SPCC integrity testing and inspection requirements for different types of SPCC Plan and industry standard applicability cases.

Figure 7-4: Summary of integrity testing and inspection program documentation for bulk storage containers at onshore facilities, by type of SPCC Plan and standard applicability case.



** Plan describes how the hybrid inspection program meets the minimal recommended elements described in Section 7.5.3.*
*** EPA Inspector should review carefully to confirm that industry standards do not apply*

The EPA inspector should also review records of frequent visual inspections by facility personnel as well as records of regular integrity testing of the container. Both API 653 and STI SP001 contain details on determining a container's suitability for continued service; the maintenance of comparison records at the facility aid in making this determination. Though §112.7(e) requires retention of all records for a period of three years, industry standards often advise that certified inspection and non-destructive examination reports be maintained for the *life of the container*.

In cases where the SPCC Plan has not identified a regularly scheduled inspection and testing program, the EPA inspector should request information on the anticipated schedule (e.g., when a baseline has not been established). If the facility has not performed any formal inspections or integrity testing of bulk storage containers so far, the EPA inspector should verify that the SPCC Plan describes: (1) the strategy for implementing an inspection and testing program and collecting baseline conditions within ten years of the installation date of the tank, or during the first five-year Plan cycle (or another schedule as identified and certified by a PE); and (2) the ongoing testing program that will be established once the baseline information has been collected (including the applicable industry standard that serves as the basis for the program). When the inspection program establishes inspection priorities for multiple containers, the EPA inspector should consider the rationale for these priorities as described in the SPCC Plan and verify implementation.

The EPA inspector should review records of regular and periodic inspections and tests of buried and aboveground piping, valves, and appurtenances. As described throughout this section, such inspections may be visual or involve other methods.

At oil production facilities, the EPA inspector should review records for inspections of bulk storage containers (including flow-through process vessels and produced water containers), piping associated with transfer operations, and flowlines or intra-facility gathering lines. When reviewing a maintenance program, such as the flowline maintenance program required under §112.9(d)(4) for oil production facilities, the EPA inspector should verify that the Plan describes how the flowlines are configured, monitored, and maintained to prevent discharges and whether the frequency and type of testing will allow for the implementation of a contingency plan when secondary containment is not provided for these lines (in accordance with §112.9(d)(3)). The EPA inspector should also verify that the program is implemented in the field; this can be done, for example, by verifying that facility personnel responsible for the maintenance of the equipment are aware of the flowline locations and are familiar with maintenance procedures, including replacement of damaged and/or leaking flowlines.

In summary, the EPA inspector should verify that the owner or operator has reports that document the implementation of the testing, evaluation, or inspection criteria set forth in the Plan. As applicable, the EPA inspector should also verify that the recommended actions that affect the potential for a discharge have been taken to ensure the integrity of the container/piping until the next scheduled inspection or replacement of the container/piping. Specifically, if the tank integrity evaluation/testing report recommends and/or requires repairs then the EPA inspector should request documentation that confirms that the repair was completed or identifies the rationale why the particular repair was not performed. When an inspection procedure is outlined in the Plan that does not meet the specific SPCC requirement, the EPA inspector should verify that the Plan includes a discussion of an environmentally equivalent measure in accordance with §112.7(a)(2). Implementation of the SPCC Plan as certified by the PE is the responsibility of the facility owner/operator (§112.3(d)(2)).

By certifying an SPCC Plan, the PE attests that the Plan has been prepared in accordance with good engineering practice, that it meets the requirements of 40 CFR part 112, and that it is adequate for the facility. Thus, if testing, evaluation, or inspection procedures have been reviewed by the certifying PE and are properly documented, they should generally be considered acceptable by the EPA inspector. However, if testing,

evaluation, or inspection procedures appear to be at odds with recognized industry standards with no rationale provided, do not meet the overall objective of oil spill response/prevention, or appear to be inadequate for the facility, appropriate follow-up action may be warranted. In this case, the EPA inspector should clearly document any concerns to assist review and follow-up by the Regional Administrator, where necessary. The EPA inspector may also request additional information from the facility owner or operator regarding the testing, evaluation, or inspection procedures provided in the Plan.

7.7 Summary of Industry Standards and Regulations

Industry standards are technical guidelines created by experts in a particular industry for use throughout that industry. These guidelines assist in establishing common levels of safety and common practices for manufacture, maintenance, and repair. Standards-developing organizations use a consensus process to establish the minimum accepted industry practice. The SPCC rule (§112.3(d)(1)(iii)) requires that a PE attest that the Plan is prepared in accordance with good engineering practices, including the consideration of applicable industry standards. Similarly, §112.6(a)(1)(iii) and §112.6(b)(1)(iii) require that the owner or operator of a qualified facility certify that the Plan is prepared in accordance with accepted and sound industry practices and standards. Standards play a role in determining good engineering practice when developing spill prevention procedures and an inspection program for an SPCC-regulated facility.

FYI – Industry standard scope

The scope of a standard will describe the type of tanks that are subject to the standard.

For example, API Standard 653, "Tank Inspection, Repair, Alteration, and Reconstruction," applies to tanks built to API 650 and API 12C specifications.

API 12R1, "Recommended Practice for Setting, Maintenance, Inspection, Operation, and Repair of Tanks in Production Service," pertains to tanks employed in production service or other similar service.

Implementing the inspection program based on a particular industry standard is ultimately up to the owner/operator. When an owner/operator indicates in the SPCC Plan that he intends to use a standard to comply with a particular rule requirement (e.g., integrity testing), then it is mandatory to implement the relevant portions of the standard (i.e., those that address integrity testing of the container). It is important to note that the principles on which industry consensus standards are based may have broad application with regard to meeting the SPCC rule's performance-based requirement for integrity testing bulk storage containers. In the unlikely situation where the scope of available inspection standards does not include a particular tank, the inspection protocols outlined in the standards may serve as a guide for developing a hybrid inspection program.

Although these guidelines are often grouped together under the term "standards," several other terms are used to differentiate among the types of guidelines:

- **Standard (or code)**—set of instructions or guidelines. Use of a particular standard is voluntary. Some groups draw a distinction between a standard and a code. The American Society of Mechanical Engineers (ASME), for example, stipulates that a code is a standard that "has been adopted by one or more governmental bodies and has the force of law..."

- **Recommended practice**—advisory document often useful for a particular situation.
- **Specification**—may be one element of a code or standard or may be used interchangeably with these terms.

This section provides an overview and description of the scope and key elements of pertinent industry inspection standards, including references to relevant sections of the standards. In each case, the purpose is to allow EPA inspectors to be familiar with the general scope and requirements. However, industry standards may be developed or revised over time. For more detailed and complete information, EPA inspectors should review the text of the actual standards. This Chapter reflects the content of the standards at the time EPA revised this Guidance. When words such as "must," "required," and "necessary," or other such terms are used in this section, they are used in describing what the various standards specify and are not considered requirements imposed by EPA, unless otherwise stated in the regulations.

Table 7-5 summarizes the facility components covered by selected industry standards and recommended practices for tanks, valves, pipes, and appurtenances that are discussed in this section. Additional standards and/or equipment manufacturers' standards may also apply.

Table 7-5: Summary of facility components covered in industry standards for inspection, evaluation, and testing.

Facility Component(s) Covered in Standard or Recommended Practice	Potentially Relevant Standards and Recommended Practices									
	API 653	STI SP001	API 570	API RP* 575	API RP* 574	API 12R1	API 1110	ASME B31.3	ASME B31.4	FTPI RP
New equipment						✓	✓	✓	✓	
Equipment that has been in service	✓	✓	✓	✓	✓	✓	✓		✓	
Shop-built AST	✓	✓		✓		✓				
Field-erected AST	✓	✓		✓		✓				
Fiberglass Reinforced Plastic tanks										✓
Container supports or foundation	✓	✓		✓		✓				
Diked area		✓								
Aboveground valves, piping, and appurtenances		✓	✓	✓	✓		✓	✓	✓	
Underground piping			✓		✓					
Offshore valves, piping, and appurtenances									✓	

* Recommended practice.

The standards that facility personnel must use for inspecting and testing at a particular facility would be specified in the SPCC Plan by the Plan preparer. If the PE requires the use of a specific standard for implementation of the Plan, the owner or operator must also reference that standard in the Plan (67 FR 47057, July 17, 2002). All actions (e.g., visual inspection or testing) performed by facility personnel must be appropriately documented and maintained in permanent facility records as per §112.7(e). Note, however, that certain industry standards may specify that an owner or operator maintain records for longer than three years, in which case the owner or operator should keep comparison records of integrity inspections and tests as directed in the standard in order to identify changing conditions of the oil storage container. Records of inspections and tests kept under usual and customary business practices satisfy the recordkeeping requirements.

In a case where the PE determines that industry inspection standards may not be appropriate in their entirety for a facility's particular tanks and configuration, this section discusses the minimum recommended elements for a hybrid inspection program.

7.7.1 API Standard 653 – Tank Inspection, Repair, Alteration, and Reconstruction

API Standard 653 – Tank Inspection, Repair, Alteration, and Reconstruction (API 653)[153] provides the minimum requirements for maintaining the integrity of carbon and alloy steel tanks built to API Standard 650 (Welded Steel Tanks for Oil Storage) and its predecessor, API 12C (Welded Oil Storage Tanks). API 653 may also be used for any steel tank constructed to a tank specification.[154]

API 653 covers the maintenance, inspection, repair, alteration, relocation, and reconstruction of welded or riveted, non-refrigerated, atmospheric pressure, aboveground, field-fabricated, vertical storage tanks after they have been placed in service. The standard limits its scope to the tank foundation, bottom, shell, structure, roof, attached appurtenances, and nozzles to the face of the first flange, first threaded joint, or first welded-end connection. The standard is intended for use by those facilities that utilize engineering and inspection personnel technically trained and experienced in tank design, fabrication, repair, construction, and inspection. Section 1 of the standard introduces the standard and details its scope. Sections 2 and 3 of the standard list the works cited and definitions used in the standard, respectively.

The standard requires that a tank evaluation be conducted when tank inspection results reveal a change in a tank from its original physical condition. Sections 4 and 5 of the standard describe procedures for evaluating an existing tank's suitability for continued operation or a change of service; for making decisions about repairs or alterations; or when considering dismantling, relocating, or reconstructing an existing tank. Section 4 of the standard details the procedures to follow in evaluating the roof, shell, bottom, and foundation of the tank. Section 5 of the standard provides a decision tree to evaluate a tank's risk of brittle fracture.

---

153 API Standard 653, "Tank Inspection, Repair, Alteration, and Reconstruction," Fourth Edition, American Petroleum Institute, April 2009 Addendum 2 January 2012.

154 See Section 1.1.3 of API Standard 653.

Section 6 of the standard focuses on factors to consider when establishing inspection intervals and covers detailed procedures for performing external and internal tank integrity inspections. Inspection intervals are largely dependent upon a tank's service history. The standard establishes time intervals for when routine in-service inspections of the tank exterior are to be conducted by the owner/operator and when external visual inspections are to be conducted by an authorized inspector. External ultrasonic thickness (UT) inspections may also be conducted periodically to measure the thickness of the shell and are used to determine the rate of corrosion. Time intervals for external UT inspections are also provided and are based on whether the corrosion rate is known.

Internal inspections (Section 6.4 of the standard) primarily focus on measuring the thickness of the tank bottom and assessing its integrity. Measured or anticipated corrosion rates of the tank bottom can be used to establish internal inspection intervals; however, the inspection interval cannot exceed 30 years using these criteria if the tank has a release prevention barrier and 20 years if the tank does not have a release prevention barrier. Alternatively, risk-based inspection (RBI) procedures, which focus attention specifically on the equipment and associated deterioration mechanisms presenting the most risk to the facility (Section 6.4.2.4 of the standard), can be used to establish internal inspection intervals; an RBI may increase or decrease the inspection interval. API 653 states that an RBI assessment shall be reviewed and approved by an authorized tank inspector and a tank design/corrosion engineer. If a facility chooses to use RBI in the development of a tank integrity testing program, the EPA inspector should verify that these parties conducted the initial RBI assessment.

An external inspection (Section 6.5 of the standard) can be used in place of an internal inspection to determine the bottom plate thickness in cases where the external tank bottom is accessible due to construction, size, or other aspects. If chosen, this option should be documented and included as part of the tank's permanent record. Owners/operators should maintain records that detail construction, inspection history, and repair/alteration history for the tank (Section 6.8 of the standard). Section 6.9 of the standard stipulates that detailed reports should be filed for every inspection performed.

Sections 7 through 11 of API 653 do not address integrity testing, but instead focus on the repair, alteration, and reconstruction of tanks. Section 12 provides specific criteria for examining and testing repairs made to tanks. Section 13 addresses the specific requirements for recording any evaluations, repairs, alterations, or reconstructions that have been performed on a tank in accordance with this standard.

Several annexes provide additional information:

- Annex A to API 653 provides background information on previously published editions of API welded steel storage tank standards.
- Annex B details the approaches that are used to monitor and evaluate the settlement of a tank bottom.

- Annex C provides sample checklists that the owner/operator can use when developing inspection intervals and specific procedures for internal and external inspections of both in-service and out-of-service tanks.
- Annex D focuses on the requirements for authorized inspector certification. Certification of authorized tank inspectors, which is valid for three years from the date of issue, requires the successful completion of an examination, as well as a combination of education and experience.
- Annex E has been removed, and is purposefully left blank.
- Annex F summarizes the non-destructive examination (NDE) requirements for reconstructed and repaired tanks.
- Annex G discusses the qualification of tank bottom examination procedures and personnel.
- Annex H provides guidance for performing a similar service assessment to establish inspection intervals for tanks for which corrosion rates have not been directly measured.
- Annex S covers the requirements for austenitic stainless steel storage tanks, constructed in accordance with API 650, Appendix S, that differ from the basic rules in the rest of API 653. Technical inquiries regarding the use of the standard can be made through API's Web site (www.api.org).

7.7.2 STI Standard SP001 – Standard for the Inspection of Aboveground Storage Tanks

STI Standard SP001 – Standard for the Inspection of Aboveground Storage Tanks (STI SP001)[155] provides inspection and evaluation criteria to determine the suitability for continued service of aboveground storage tanks until the next scheduled inspection. STI SP001 applies to the inspection of aboveground storage tanks, including shop-fabricated tanks, field-erected tanks, and portable containers, as defined in the standard, as well as their containment systems. The inspection and testing requirements for field-erected tanks are covered separately in Appendix B of the standard. Specifically, the standard applies to ASTs storing stable, flammable, and combustible liquids at atmospheric pressure with a specific gravity less than approximately 1.0, and those storing liquids with operating temperatures between ambient temperature and 200 degrees Fahrenheit (93.3°C).[156] At a minimum, the following tank components shall be inspected (as applicable): primary and secondary tanks, supports, anchors, foundation and external supports, gauges and alarms, insulation, appurtenances, normal and emergency vents, release prevention barriers, and spill control systems.

After providing general information and definitions, Section 3 of the standard addresses safety considerations, and Section 4 addresses AST inspector qualifications.

---

155 STI Standard SP-001, "Standard for the Inspection of Aboveground Storage Tanks," 5th Edition September 2011.

156 Given this operating range, the standard may not apply to certain tanks such as those containing asphalt cement.

Section 5 of the standard addresses the criteria, including AST type, size, type of installation, corrosion rate, and previous inspection history, if any, that should be used to develop a schedule of inspections for each AST.

A Table of Inspection Schedules (Table 5.5) places tanks into one of three categories and establishes different requirements regarding the type and frequency of periodic inspection by tank owner/operators as well as formal external and internal inspections by a certified inspector. The factors used for categorizing tanks include:

- Tank size,
- Whether the tank is in contact with the ground,
- The presence or absence of secondary containment or spill control, and
- The presence or absence of a continuous release detection method (CRDM).

Section 6 of the standard provides guidelines for the periodic inspections conducted by the owner or his/her designee. The owner's inspector is to complete an AST Record for each AST or tank site, as well as a Monthly Inspection Checklist and an Annual Inspection Checklist. Monthly inspections should monitor water accumulation to prevent Microbial Influenced Corrosion (MIC), and action should be taken if MIC is found. Additional requirements for field-erected tanks are in Appendix B of STI SP001.

Section 7 of the standard contains the minimum inspection requirements for formal external inspections, which are to be performed by a certified inspector. Inspections should cover the AST foundations, supports, secondary containment, drain valves, ancillary equipment, piping, vents, gauges, grounding system (if any), stairways, and coatings on the AST. Original shell thickness should be determined using one of several suggested methods. Ultrasonic Thickness Testing (UTT) readings are to be taken at different locations of the AST depending upon whether the AST is horizontal, vertical, rectangular, and/or insulated. The final report should include field data, measurements, pictures, drawings, tables, and an inspection summary, and should specify the next scheduled inspection.

Section 8 of the standard details the minimum inspection requirements for formal internal inspections, which are to be performed by a certified inspector. A formal internal inspection includes the requirements of an external inspection with some additional requirements for specific situations that are outlined in the standard. Double-wall tanks and secondary containment tanks may be inspected by checking the interstice for liquid or by other equivalent methods. For elevated ASTs where all external surfaces are accessible, the internal inspection may be conducted by examining the tank exterior using such methods as Ultrasonic Thickness Scans (UTS). For all other situations, entry into the interior of the AST is necessary. Internal inspection guidelines are detailed separately for horizontal ASTs and for vertical and rectangular ASTs in Sections 8.2 and 8.3 of the standard, respectively. Additional requirements for field-erected tanks are in Appendix B. The final report should contain elements similar to reports prepared for external inspections.

Section 9 of the standard addresses leak testing methods. For shop-fabricated ASTs, the standard references the Steel Tank Institute Recommended Practice R912, "Installation Instructions for Shop Fabricated Stationary Aboveground Storage Tanks for Flammable, Combustible Liquids." The standard also references DOT regulations for portable containers:

- 49 CFR part 173.28, Reuse, reconditioning, and remanufacturing of packaging, mainly for drums;
- 49 CFR part 178 – 49 CFR Subpart O, Testing and certification of intermediate bulk containers (IBCs); and
- 49 CFR part 180.605, or equivalent, for portable container testing and recertification.

Section 10 of the standard addresses the suitability for continued service based on the results of formal internal and/or external inspections performed by a certified inspector. For ASTs that show signs of damage caused by MIC, the criteria for assessing their suitability for continued service differ based on categories associated with the level of reduction of the shell thickness (as per Section 5 of STI SP001). For other tank damage, an engineer experienced in AST design or a tank manufacturer should determine if an inspection is required for any AST that was exposed to fire, natural disaster, excessive settlement, overpressure, or damage from cracking.

Section 11 of the standard details recordkeeping requirements. Appendix A presents supplemental technical information including terms commonly associated with ASTs, and Appendix B presents information for the inspection of field-erected ASTs.

For more information on STI SP001, please visit the Steel Tank Institute Web site, http://www.steeltank.com.

7.7.3 STI Standard SP031 - Standard for Repair of Shop Fabricated Aboveground Tanks for Storage of Combustible & Flammable Liquids

STI Standard SP031 - Standard for Repair of Shop Fabricated Aboveground Tanks for Storage of Combustible & Flammable Liquids[157] covers the repair and modification of an atmospheric-type shop fabricated carbon and stainless steel tanks. It applies to tanks storing flammable and combustible liquids at atmospheric pressure with a specific gravity not greater than 1.0. STI SP031 is referenced in STI SP001 for repairs or alterations to an AST.

[157] STI SP031 Standard for Repair of Shop Fabricated Aboveground Tanks for Storage of Combustible & Flammable Liquids 4th Edition November 2008, Revised November 2012

7.7.4 API Recommended Practice 575 – Guidelines and Methods for Inspection of Existing Atmospheric and Low-Pressure Storage Tanks

API Recommended Practice 575 – Guidelines and Methods for Inspection of Existing Atmospheric and Low-Pressure Storage Tanks[158] (API RP 575), which supplements API 653, covers the inspection of atmospheric tanks (e.g., cone roof and floating roof tanks) and low-pressure storage tanks (i.e., those that have cylindrical shells and cone or dome roofs) that have been designed to operate at pressures from atmospheric to 15 pounds per square inch gauge (psig). (API RP 572[159] covers vessels operating above 15 psig.) API RP 575 applies only to the inspection of atmospheric and low-pressure storage tanks that have been in service. In addition to describing the types of storage tanks and their construction and maintenance, API RP 575 also covers the reasons for inspection, causes of deterioration, frequency and methods of inspection, methods of repair, and the preparation of records and reports.

The recommended practice is organized as follows:

- Section 1 of API RP 575 introduces the recommended practice and details its scope.
- Section 2 lists codes, standards and related publications that are cited in the recommended practice.
- Section 3 defines terms relevant to API RP 575.
- Section 4 describes specific types of atmospheric and low-pressure storage tanks including construction materials and design standards and their use.
- Section 5 covers the reasons for inspection and causes of deterioration of both steel and non-steel storage tanks. Section 5 also covers the deterioration and failure of auxiliary equipment as well as a similar service methodology for establishing tank corrosion rates.
- Section 6 of API RP 575 addresses inspection frequency and scheduling; it mainly defers to the inspection frequency requirements described in API 653 and API RP 12R1.
- Section 7 covers the methods of inspection including the external inspection of both in-service and out-of-service tanks and the internal inspection of out-of-service tanks.
- Section 8 addresses leak testing and hydraulic integrity of tank bottoms.
- Section 9 focuses on the integrity of repairs and alterations, which stresses the importance of inspecting repairs to ensure they have been properly done.

---

158 API RP 575, "Guidelines and Methods for Inspection of Existing Atmospheric and Low-Pressure Storage Tanks," 2nd ed., American Petroleum Institute, May, 2005

159 API 572 Inspection of Pressure Vessels, 3rd Edition, November, 2009

- Section 10 addresses recordkeeping and inspection reports.
- Appendix A describes selected methods for non-destructive examination of tanks, including ultrasonic thickness measurement, ultrasonic corrosion testing, ultrasonic shear wave testing, magnetic flux testing and robotic inspection.
- Appendix B contains similar service evaluation tables for corrosion rates.
- Appendix C provides a selected bibliography.

7.7.5 API Recommended Practice 12R1 – Recommended Practice for Setting, Maintenance, Inspection, Operation, and Repair of Tanks in Oil Production Service

API Recommended Practice 12R1 – Recommended Practice for Setting, Maintenance, Inspection, Operation, and Repair of Tanks in Production Service (API RP 12R1)[160] provides guidance on new tank installations and maintenance of existing oil production tanks. These tanks are often referred to as "upstream" or "extraction and production (E&P) tanks."

This recommended practice is primarily intended for tanks fabricated to API Specifications 12B, D, F, and P that are employed in on-land production service.[161] The basic principles in this recommended practice can also be applied to other atmospheric tanks in similar oil and gas production, treating, and processing services; however, they are not applicable to refineries, marketing bulk stations, petrochemical plants, or pipeline storage facilities operated by carriers. According to the recommended practice, tanks that are fabricated to API Standards 12C or 650 should be maintained in accordance with API 653, summarized above.

The recommended practice is organized as follows:

- Sections 1, 2, and 3 describe the scope of the standard, the 19 standards it references, and the relevant definitions, respectively. The remaining four main sections describe the recommended practices.
- Section 4 provides recommended practices for setting of new or relocated tanks and connecting tanks.
- Section 5 recommends practices for safe operation and spill prevention for tanks.[162]

---

160 API Recommended Practice 12R1, "Recommended Practice for Setting, Maintenance, Inspection, Operation, and Repair of Tanks in Production Service," 5th edition. American Petroleum Institute. August 1997, Reaffirmed April 2008.

161 API Specifications 12B, D, F, and P correspond to bolted tanks for storage of production liquids, field welded tanks for storage of production liquids, shop welded tanks for storage of production liquids, and specification for fiberglass reinforced plastic tanks, respectively.

162 The scope of API RP 12R1 states that "the spill prevention and examination/inspection provisions of this recommended practice should be a companion to the spill prevention control and countermeasures (SPCC) to prevent environmental damage."

- Section 6 details the recommended practices for routine operational and external and internal condition examinations, internal and external inspections, maintenance of tanks, and recordkeeping. Tables 1 and 2 detail the type of observations, frequency, and associated personnel requirements for internal and external tank inspections. Records from these inspections should be retained with permanent equipment records.

- Section 7 provides guidance for the alteration or repair of various tank components.

API RP 12R1 also contains nine appendices detailing the recommended requirements for qualified inspectors, sample calculations for venting requirements, observations regarding shell corrosion and brittle fracture, checklists for internal and external condition examinations and inspections, details regarding the minimum thickness of tank elements, and various figures and diagrams.

7.7.6 API 570 – Piping Inspection Code: In-Service Inspection, Rating, Repair, and Alteration, of Piping Systems

API 570 – Piping Inspection Code: In-Service Inspection, Rating, Repair, and Alteration, of Piping Systems (API 570)[163] covers procedures for metallic and fiberglass reinforced plastic piping systems and their associated pressure relieving devices that have been in service. API 570 was developed for the petroleum refining and chemical process industries but may be used, where practical, for any piping system. In-service piping systems covered by API 570 include those used for process fluids, hydrocarbons, and similar flammable or toxic fluids. API states that this standard is not a substitute for the original construction requirements governing a piping system before it is placed in service. API 570 is intended for use by organizations that maintain or have access to an authorized inspection agency; a repair organization; and technically qualified piping engineers, inspectors, and examiners. The code is organized as follows:

- Section 4 outlines responsibilities and associated procedures and qualifications. The owner/user of piping systems is responsible for the piping system inspection program, inspection frequencies, and maintenance of piping systems in accordance with this standard. The owner/user organization is also responsible for activities related to the rating, repair and alteration of its piping systems.

- Section 5 addresses the specific inspection and pressure testing practices for in-service piping systems.

- Section 6 addresses the frequency and extent of inspection of piping. Inspection intervals for piping are based on the forms of degradation possible and consequence of failure. Risk-based assessment may be used to determine inspection intervals or an interval can be established which takes into account the corrosion rate and remaining life calculations; piping service

[163] API 570, "Piping Inspection Code: In-Service Inspection, Rating, Repair, and Alteration of Piping Systems," 3rd ed., American Petroleum Institute, November 2009.

classification; applicable jurisdictional requirements; and the judgment of the inspector, the piping engineer, the piping engineer supervisor, or a corrosion specialist.

Table 2 of API 570 provides maximum inspection intervals for piping based on piping service classification:

- Class 1 poses the highest potential of resulting in an immediate emergency if a leak were to occur;
- Class 2 is for services not included in other categories and includes the majority of piping;
- Class 3 is for services that are flammable but do not significantly vaporize when they leak and are not located in high-activity areas; and
- Class 4 is for services that are essentially nonflammable and nontoxic.

The maximum inspection interval for in-service aboveground piping listed in Section 6 Table 2 is as follows:

- Class 1: Thickness measurements – 5 years, visual inspection – 5 years
- Class 2: Thickness measurements – 10 years, visual inspection – 5 years
- Class 3: Thickness measurements – 10 years, visual inspection – 10 years
- Class 4: Thickness measurements – optional, visual inspection – optional

The inspection interval may be less depending on corrosion rates and remaining life. Thickness measurements must be obtained at ½ the remaining life determined from corrosion rates or the intervals listed in Table 2 whichever is less.

The type and frequency of inspections for buried piping is presented separately in Section 9 (see below).

- Section 7 addresses data evaluation, analysis, and recording. The owner/operator should maintain permanent records for all piping systems covered by API 570.
- Section 8 provides guidelines for repairing, altering, and rerating piping systems and refers to ASME B31.3 for in-service repairs.
- Section 9 addresses the inspection of buried piping. Inspecting buried process piping is different from inspecting other process piping because the inspection is hindered by the inaccessibility of the affected areas of the piping.
- Annex A, B, and C address inspector certification, requests for interpretations, examples of repairs, and the external inspection checklist for process piping, respectively.

7.7.7 API Recommended Practice 574 – Inspection Practices for Piping System Components

API Recommended Practice 574 – Inspection Practices for Piping System Components (API RP 574)[164] covers inspection practices for piping, tubing, valves (other than control valves), and fittings used in petroleum refineries and chemical plants. It addresses inspection planning processes, inspection intervals and techniques and types of records. API RP 574 is intended to supplement API 570. It does not cover inspection of specialty items, such as instrumentation and control valves. The recommended practice is organized as follows:

- Section 1 introduces the recommended practice and details its scope.
- Sections 2 and 3, respectively, list the references and definitions used throughout the recommended practice.
- Section 4, which begins the substantive portion of the recommended practice, details the types, material specifications, sizes, and other characteristics of the components of the piping system, which include the piping, tubing, valves, fittings, flanges and joints.
- Section 5 details common joining methods, i.e., welding, threading and flanging.
- Section 6 presents the rationale for inspecting the piping system: to identify active deterioration mechanisms and to specify repair, replacement, or future inspections for affected piping. It suggests examining inspection history and points to API 570 as providing the basic requirements for such an inspection program.
- Section 7 discusses the development of an inspection plan, including risk-based plans and interval-based plans. It presents considerations for monitoring the piping system components for corrosion and inspecting for damage.
- Section 8 provides guidelines for establishing the frequency and extent of inspection using the following conditions to determine the frequency of inspection: the consequences of a failure (piping classification, see summary of API 570 in *Section 7.7.6* for a description) degree of risk, amount of corrosion allowance remaining, historical data available, and regulatory requirements. It also discusses inspections on piping that is operating and not in operation.
- Section 9 outlines the safety precautions and preparatory work to be performed prior to inspecting the piping system components. The inspection tools commonly used to inspect piping are listed in Section 9.2.2 of API RP 574.
- Section 10 details the specific procedures and practices to be followed when inspecting the components of the piping system such as external and internal visual inspection, pressure tests,

[164] API RP 574, "Inspection Practices for Piping System Components," 3rd ed., American Petroleum Institute, November 2009.

and other methods. This section also covers the inspection of underground piping (Section 10.10) and new construction (Section 10.11).

- Section 11 refers to ASME B31.3 in describing the procedures a piping engineer should follow to determine the thickness at which piping and valves and flanged fittings should be retired.
- Section 12 addresses recordkeeping.
- Appendix A of the recommended practice provides an external inspection checklist for process piping.

7.7.8 API Recommended Practice 1110 – Pressure Testing of Steel Pipelines for the Transportation of Gas, Petroleum Gas, Hazardous Liquids, Highly Volatile Liquids or Carbon Dioxide

API Recommended Practice 1110 – Pressure Testing of Steel Pipelines for the Transportation of Gas, Petroleum Gas, Hazardous Liquids, Highly Volatile Liquids or Carbon Dioxide (API RP 1110)[165] provides guidance regarding the procedures, equipment, and verification of pressure test results, as well as guidance for meeting the requirements of Integrity Management set out in API Standard 1160 and ASME B31.8S. Pressure testing uses a liquid test medium (typically water) to apply internal pressure to a segment of pipe above its normal or maximum operating pressure for a fixed period of time.

The main sections of this standard are Pressure Test Planning, Pressure Test Implementation, and Pressure Test Records and Drawings. Planning for a pressure test involves safety considerations, written test procedures, pipeline operating considerations, selection of a test medium, equipment and materials, target test pressures and durations, and other related issues. There are three basic types of pressure tests based on the intended purpose:

- Spike test— a short duration, high amplitude (pressure ratio) test;
- Strength test— conducted to establish the operating pressure limit of a pipeline; and
- Leak test— used to determine if a pipeline is leaking, and can be used in combination with the other test types

For implementation of pressure tests, personnel should follow site-specific test procedures including appropriate test pressures and the duration of the pressure test. Other operational aspects of pressure test implementation address the proper qualifications of personnel, pressurization, the test period, searching for leaks, and disposal of the test medium. Lastly, adequate test records and drawings should be kept for the useful

[165] API Recommended Practice 1110, "Pressure Testing of Liquid Petroleum Pipelines," 5th edition, American Petroleum Institute, June 2007.

life of the pipeline to document the operating pressure limit of a section of pipe or to demonstrate compliance with integrity management requirements.

7.7.9 API Recommended Practice 579-1/ASME FFS-1, Fitness-for-Service, Part 3

This recommended practice[166] addresses "Assessment of Existing Equipment for Brittle Fracture" and provides guidelines for evaluating the resistance to brittle fracture of existing carbon and low alloy steel pressure vessels, piping, and storage tanks. If the results of the fitness-for-service assessment indicate that the AST is suitable for the current operating conditions, then the equipment can continue to be operated under the same conditions provided that suitable monitoring/inspection programs are established. API RP 579-1/ASME FFS-1 is intended to supplement and augment the requirements in API 653. That is, when API 653 does not provide specific evaluation procedures or acceptance criteria for a specific type of degradation, or when API 653 explicitly allows the use of fitness-for-service criteria, API RP 579-1/ASME FFS-1 may be used to evaluate the various types of degradation or test requirements addressed in API 653.

A brittle fracture assessment may be warranted based on operating conditions and/or the condition of the AST. API RP 579-1/ASME FFS-1 provides separate brittle fracture assessment procedures for continued service based on three levels. All three apply to pressure vessels, piping, and tankage, although a separate assessment procedure is provided for tankage.

- Level 1 assessments are used for equipment that meets toughness requirements in a recognized code or standard (e.g., API 650).
- Level 2 assessments exempt equipment from further assessment and qualify it for continued service based on one of three methods that utilize operating pressure and temperature; performance of a hydrotest; or the materials of construction, operating conditions, service environment, and past operating experience.
- Level 3 assessments, which normally utilize a fracture mechanics methodology, are used for tanks that do not meet the acceptance criteria for Levels 1 and 2.

A decision tree in API RP 579-1/ASME FFS-1 (Figure 3.3, Brittle Fracture Assessment for Storage Tanks) outlines this assessment procedure. The Level 1 and Level 2 brittle fracture assessment procedures are nearly identical to those found in API 653, Section 5, with a few notable exceptions: API 653 does not use the Level 1 and Level 2 designations; API 653 applies only to tanks that meet API 650 (7th edition or later) construction standards, whereas API 579-1/ASME FFS-1 applies to tanks that meet toughness requirements in the "current construction code;" and the two standards set a different limit on the maximum membrane stress (the stress forces that form within the shell as a result of the pressure of the liquid inside the vessel). There is, however, one major difference between API 653 and API 579-1/ASME FFS-1: API 653 Section 5 does not allow for an exemption of the hydrostatic test requirement whereas API 579-1/ASME FFS-1 does. API 579-1/ASME FFS-1

[166] API Recommended Practice 579, "Fitness for Service," 2nd Edition, American Petroleum Institute, June 2007.

allows for a probabilistic evaluation of the potential for brittle fracture using engineering calculations (i.e., a Level 3 assessment) in lieu of the hydrostatic test.

7.7.10 API Standard 2610 – Design, Construction, Operation, Maintenance, and Inspection of Terminal and Tank Facilities

This standard[167] has short sections on petroleum terminals, pipeline tankage facilities, refinery facilities, bulk plants, lube blending and packaging facilities, asphalt plants, and aviation service facilities. These sections mainly serve to define what is meant by each type of facility. The standard does not apply to installations covered by API Standard 2510 and API RP 12R1, as well as specific types of facilities and equipment listed in the standard. The standard lists governmental requirements and reviews that should be conducted to ensure that facilities meet applicable federal, state, or local requirements (Section 1.3); and has an extensive list of standards, codes, and specifications to use (Section 2.1) and definitions (Section 3). The standard is further organized as follows:

- Section 4 covers the site selection and spacing requirements for the design and construction of new terminal facilities.
- Section 5 addresses the methods of pollution prevention and waste management practices in the design, maintenance, and operation of petroleum terminal and tank facilities.
- Section 6 covers the safe operation of terminals and tanks including hazard identification, operating procedures, safe work practices, emergency response and control procedures, training, and other provisions.
- Section 7 covers fire prevention and protection, including tank overfill protection and inspection and maintenance programs. This section also covers considerations for special products.
- Section 8 covers aboveground petroleum storage tanks and appurtenances such as release prevention, leak detection, and air emissions. This section covers operations, inspections, maintenance, and repair for aboveground and underground tanks.
- Section 9 addresses dikes and berms.
- Section 10 covers pipe, valves, pumps, and piping systems.
- Section 11 covers loading, unloading, and product transfer facilities and activities including spill prevention and containment.
- Section 12 addresses the procedures and practices for achieving effective corrosion control.

[167] API Recommended Practice 2610, "Design, Construction, Operation, Maintenance, and Inspection of Terminal and Tank Facilities," 2nd edition, American Petroleum Institute, May 2005.

- Section 13 addresses structures, utilities, and yards.
- Section 14 covers removal or decommissioning of facilities.

All of these sections make extensive reference to the regulatory requirements and applicable industry standards.

7.7.11 RP FTPI 2007-1 Recommended Practice for the In-service Inspections of Aboveground Atmospheric Fiberglass Reinforced Plastic Tanks and Vessels

The Fiberglass Tank and Pipe Institute (FTPI) 2007-1 Recommended Practice includes recommended inspector qualifications, periodic preventive maintenance inspections, certified external inspections, certified integrity inspections, internal inspections and alternate non-intrusive inspection methods. It also includes report forms for monthly, annual and periodic preventive maintenance and certified inspections and a section on aboveground fiberglass tank fabrication information. RP FTPI 2007-1 may be used for the inspection of aboveground fiberglass tanks or vessels.

The purpose of this Recommended Practice is to provide procedures for conducting periodic preventive maintenance inspections and certified inspections of fiberglass reinforced plastic atmospheric tanks and vessels in corrosive industrial and commercial service after a set period of time and when there is a change of service. The procedures are intended to:

- Minimize maintenance costs;
- Ensure compliance with environmental and safety requirements;
- Minimize system failures; and
- Ensure that proper engineering, construction and maintenance practices are in place.

Recommended Practice FTPI 2007-1 specifies the requirements for external and internal inspections to be performed by certified inspectors as follows:

Certified External Inspections

- Every 5 years for tanks or vessels in Hazardous Substance service;
- Every 10 years for tanks/vessels greater than 10,000 gallons capacity and in other service;
- If evidence of material stress appears;
- If tank or vessel leaks occur;
- Before there is a change in service to a dissimilar stored material; or
- If a tank or vessel is relocated.

Certified Integrity Inspections

- Every 20 years for tanks/vessels in Hazardous Substance service;
- Every 20 years for tanks/vessels greater than 10,000 gallons capacity and in other service;
- If evidence of material stress appears;
- If tank or vessel leaks occur;
- Before there is a change in service to a dissimilar stored material; or
- If a tank or vessel is relocated.

7.7.12 ASME B31.3 – Process Piping

ASME B31.3 – Process Piping[168] is the generally accepted standard of minimum safety requirements for the oil, petrochemical, chemical, pharmaceutical, textile, paper, and semiconductor industries' process piping design and construction (for process piping already in service, other standards should be used, such as API 570, "Piping Inspection Code"). ASME B31.3 is written to be very broad in scope to cover a range of fluids, temperatures, and pressures. This broad coverage leaves a great deal of responsibility with the owner to use good engineering practices. The safety requirements for the design, examination, and testing of process piping vary in stringency based on four different categories of fluid service. Categories include:

- Category D for a low hazard of fluid service,
- Category M for a high hazard of fluid service,
- High Pressure for piping designated by the owner as being in high pressure fluid service[169], and
- Normal to indicate all remaining fluid services.

It is the owner's responsibility to select the appropriate fluid service category, which determines the appropriate examination requirements.

ASME B31.3 distinguishes between inspection and examination. Inspection "applies to functions performed for the owner by the owner's Inspector or the Inspector's delegates." The owner is responsible, through the Inspector, for verifying that the required examinations and testing have been completed. The examination of process piping is to be completed by an examiner who demonstrates sufficient qualifications to perform the specified examination and who has training and experience records kept by his/her employer that

---

168 ASME Code for Pressure Piping, B31.3-2008, "Process Piping," The American Society of Mechanical Engineers, revision of ASME 31.3-2006, 2008.

169 High Pressure is considered in ASME B31.3 to be pressure in excess of that allowed by the ASME b16.5 Class 2500 rating for the specified design temperature and material group; however, there are not specified pressure limitations for ASME B31.3.

can support these qualifications.[170] Different types of examinations performed include visual, radiographic, ultrasonic, in-process, liquid-penetrant, magnetic-particle, and hardness testing.

While these examinations are a part of the quality assurance procedures for new piping, leak testing should also be performed to test the overall system. According to ASME B31.3, leak testing is required for all new piping systems other than those classified as Category D, which can be examined for leaks after being put into service. Options for leak testing include hydrostatic, pneumatic, hydro pneumatic, and alternative leak tests.

The standard requires that records detailing the examination personnel's qualifications and examination procedures be kept for at least five years. Test records or the inspector's certification that the piping has passed pressure testing are also required to be retained.

7.7.13 ASME Code for Pressure Piping B31.4-2006 – Pipeline Transportation Systems for Liquid Hydrocarbons and Other Liquids

ASME Code for Pressure Piping B31.4-2006 – Pipeline Transportation Systems for Liquid Hydrocarbons and Other Liquids[171] describes "engineering requirements deemed necessary for safe design and construction of pressure piping." These requirements are for the "design, materials, construction, assembly, inspection, and testing of piping transporting liquids" such as crude oil and liquid petroleum products between various facilities. Piping includes bolting, valves, pipes, gaskets, flanges, fittings, relief devices, pressure-containing parts of other piping components, hangers and supports, and any other equipment used to prevent the overstressing of pressure-containing pipes. This code's primary purpose is to "establish requirements for safe design, construction, inspection, testing, operation, and maintenance of liquid pipeline systems for protection of the general public and operating company personnel."

The personnel inspecting the piping are deemed qualified based on their level of training and experience and should be capable of performing various inspection services such as right-of-way and grading, welding, coating, pressure testing, and pipe surface inspections. Inspections of piping material and inspections during piping construction should include the visual evaluation of all piping components. Once construction is complete, these piping components and the entire system should be tested. Testing methods include hydrostatic testing of internal pressure piping; leak testing; and qualification tests based on a visual examination, bending properties, determination of wall thickness, determination of weld joint factor, weldability, determination of yield strength, and the minimum yield strength value.

Records detailing the design, construction, and testing of the piping should be kept in the files of the operating company for the life of the facility.

---

170 ASME B31.3 does not have specific requirements for an examiner, but SNT-TC-1A, "Recommended Practice for Nondestructive Testing Personnel Qualification and Certification," acts as an acceptable guide.

171 ASME Code for Pressure Piping, B31.4-2006, "Pipeline Transportation Systems for Liquid Hydrocarbons and Other Liquids," The American Society of Mechanical Engineers, revision of ASME B31.4-2002, 2006.

7.7.14 DOT 49 CFR part 180.605 – Requirements for Periodic Testing, Inspection, and Repair of Portable Tanks and Other Portable Containers

Section 180.605[172] applies to any portable tank constructed to a DOT (e.g., 51, 56, 57, 60, or intermodal [IM]) or United Nations (UN) specification. According to these requirements, a portable tank must be inspected prior to further use if it shows evidence of a condition that might render it unsafe for use, has been damaged in an accident, has been out of service for more than a year, has been modified, or is in an unsafe operating condition. All tanks must receive an initial inspection prior to being placed into service and a periodic inspection or intermediate periodic inspection every two to five years. The timeframe between inspections depends upon the tank's specification.

Intermediate periodic inspections must include an internal and external examination of the tank and fittings, a leak test, and a test of the service equipment. The periodic inspection and test must include an external and internal inspection and a sustained air pressure leak test, unless exempted. For tanks that show evidence of damage or corrosion, an exceptional inspection and test is mandated. The extent of the inspection is dictated by the amount of damage or deterioration of the portable tank. Specification-60 tanks are further tested by filling them with water. Specification-IM or Specification-UN portable tanks must also be hydrostatically tested. Any tank that fails a test may not return to service until it is repaired and retested. An approval agency must witness the retest and certify the tank for return to service. The date of the last pressure test and visual inspection must be clearly marked on each portable tank. A written record of the dates and results of the tests, including the name and address of the person performing the test, is to be retained by the tank owner or authorized agent.

Requirements for retest and inspection of Intermediate Bulk Containers (IBCs) are specified in 49 CFR 180.352. Requirements depend on the IBC shell material. For metal, rigid plastic, and composite IBCs, they include a leakproof test and external visual inspection every 2.5 years from the date of manufacture or repair. They also require an internal inspection every 5 years to ensure that the IBC is free from damage and capable of withstanding the applicable conditions. Flexible, fiberboard, or wooden IBCs must be visually inspected prior to first use and permitted reuse. Records of each test must be kept until the next test, or for at least 2.5 years from the date of the last test.

Design standards and specifications for initial qualification and reuse performance testing for portable tanks, drums, and IBCs are contained in 49 CFR part 178, Specifications for Packaging. See http://www.ecfr.gov/cgi-bin/text-idx?c=ecfr&tpl=%2Findex.tpl.

---

172 49 CFR part 180.605, "Requirements for Periodic Testing, Inspection, and Repair of Portable Tanks," Department of Transportation, 64 FR 28052, May 24, 1999, as amended at 67 FR 15744, April 3, 2002 and 68 FR 45042 revision.

7.7.15 FAA Advisory Circular 150/5230-4A – Aircraft Fuel Storage, Handling, and Dispensing on Airports

FAA Advisory Circular 150/5230-4A – Aircraft Fuel Storage, Handling, and Dispensing on Airports[173] identifies standards and procedures for storage, handling, and dispensing of aviation fuel on airports. The Federal Aviation Administration (FAA) recommends the standards and procedures referenced in the Advisory Circular (AC) for all airports. The FAA accepts these standards as one means of complying with 14 CFR Part 139, Certification of Airports, as it pertains to fire safety in the safe storage, handling, and dispensing of fuels used in aircraft on airports but not in terms of quality control. Although airports that are not certificated under 14 CFR part 139 are not required to develop fuel safety standards, the FAA recommends that they do so.

This AC is not intended to replace airport procedures developed to meet requirements imposed because of the use of special equipment, nor to replace local regulations. For specific provisions, the other standards that are referenced in this AC are:

- For fuel storage, handling and dispensing, the National Fire Prevention Association's "Standard for Aircraft Fuel Servicing."
- For refueling and quality control procedures, the National Air Transportation Association's "Refueling and Quality Control Procedures for Airport Service and Support Operations." This provides information about fuel safety, types of aviation fuels, fueling vehicle safety, facility inspection procedures, fueling procedures, and methods for handling fuel spills. API also publishes documents pertaining to refueling and facility specifications.

The AC also requires fuel safety training for airports certificated under 14 CFR part 139. (See http://www.faa.gov/airports/resources/advisory_circulars/index.cfm.)

7.7.16 FAA Advisory Circular 150/5210-20 – Ground Vehicle Operations on Airports

FAA Advisory Circular 150/5210-20 – Ground Vehicle Operations on Airports[174] provides "guidance to airport operators in developing training programs for safe ground vehicle operations and pedestrian control on the airside of an airport." Specifically, this advisory circular provides recommended operating procedures for ground vehicles. It also provides two appendices containing samples of the training curriculum and training manual. The sample training manual in Appendix B provides airport operators with a template for developing and implementing policies or procedures for controlling ground vehicles and equipment on an airport, for example requirements for fuel trucks transporting oil. Airport operators would use the format but adapt the requirements to specific conditions found on the airport.
(See http://www.faa.gov/airports/resources/advisory_circulars/index.cfm.)

---

173 FAA Advisory Circular 150/5230-4A, "Aircraft Fuel Storage, Handling, and Dispensing on Airports," Federal Aviation Administration, U.S. Department of Transportation, June 18, 2004.

174 FAA Advisory Circular 150/5210-20, "Ground Vehicle Operations on Airports," Federal Aviation Administration, U.S. Department of Transportation, March 31, 2008.

Index

3A Sanitary Standards, 7-48

Aboveground piping
Inspection requirements, 7-21, 7-59, 7-70

Aboveground storage tank
(AST), 1-7, 4-19, 7-11

Accumulation of oil
Removal, 4-62, 7-14, 7-23

Active measures, secondary containment
Considerations in selecting, 4-25, 4-26

Definition, 4-24, 4-25

Deployment of, 4-26, 4-27

Oil-filled operational equipment, 4-27

Role of EPA Inspector, 4-27, 4-28, 4-29

Acts of war or terrorism, 1-19, 4-12, 4-65, 4-68, 5-13

Adjuvant oil, 1-21, 2-50

Airport, 1-10, 2-29, 6-10, 7-79

Alteration
Industry standard, 7-62, 7-63, 7-66, 7-67, 7-69

Storage capacity. *See* Storage capacity, Alteration

Amendment
SPCC Plan, 2-40, 3-26, 4-45, 5-18, 6-22, 7-28, 7-52

Animal fat, 1-5, 1-10, 1-18, 1-21, 1-24, 2-4, **2-5**, 2-8, 2-44, 3-6, 3-12, 3-21, 4-14, 4-37, 4-59, 5-3, 7-2, 7-10, 7-15

Appendix G template
Qualified facility. *See* Qualified facility, Appendix G template

Applicability
FRP, 1-2, 1-4, 1-5, 1-16, 2-10, 2-15, 2-19, 2-40, 2-59, 4-39, 4-44, 4-45, 4-46, 4-51, 7-52, 7-53

Applicability, SPCC
Appeal process, **2-53**

Description, **2-1**, **2-2**, 2-6, 2-8, 2-9, **2-54**, **2-61**

Flowchart, **2-60**

OWS, **5-1**, 5-3, 5-7, 5-12, 5-13

Approval of State Underground Storage Tank Programs
40 CFR part 281, 2-43

Asphalt
Asphalt cement, 1-21, 2-5

Cutback, 1-21, 2-5

Emulsions, 1-21, 2-5

Hot-mix asphalt, 1-21, 2-5

Austenitic stainless steel, 7-8, *7-15*, *7-16*, *7-17*, *7-18*, 7-64

Barrier
Secondary containment example, 4-8

Secondary containment examples, 4-9, 4-25, 4-27, 4-33

Baseline
Inspections, 7-37, 7-38, 7-56, 7-59, *See* Integrity testing, Baseline

Berm
Secondary containment example, 2-19, 3-6, 3-7, 4-8, 4-9, 4-15, 4-17, 4-18, 4-26, 4-27, 4-29, 4-32, 4-33, 4-53, 4-63, 4-64, 7-74

Best Management Practice (BMP), 2-46, 3-11, 5-4

Biodiesel, **2-8**

Blowout prevention (BOP) assembly, 3-5, 3-35, 3-36

Boom
Secondary containment example, 4-8, 4-9, 4-26, 4-27, 4-33

Breakout tank
Definition of, 2-31

Brittle fracture evaluation, 1-18, 3-3, 3-28, 7-2, 7-3, 7-20, 7-21, 7-20, 7-50, 7-55, 7-62, 7-69, 7-73, 7-74

Bulk storage container
Definition, **2-54**, 2-56, 2-57, 2-58

Integrity testing requirements, 1-23, **3-21**

Bunkered tank, 2-37, 2-43

Buried metallic tank
Testing requirements, 3-9

Buried piping
Requirements, 3-13, 3-14, 3-15, 3-16, 3-31, 4-50, 7-5, 7-21, 7-22

Certification
SPCC Plan, 1-18, 1-19, 1-20, 3-1, 3-7, 3-34, 4-8, 4-31, 4-40, 4-68, 5-17, 6-22, 7-9, 7-47, 7-52

Certification of the Applicability of the Substantial Harm Criteria. *See* FRP substantial harm criteria:certification of

Change in service, 2-40, 3-28, 7-2, 7-20, 7-21

Clean Water Act, 1-1, 1-2, **1-3**, 1-4, 1-6, 1-8, 1-9, 1-25, 2-2, 2-3, 2-7, 2-33, 2-34, 2-36, 2-52, 5-4

Collection system
Secondary containment example, 4-8, 4-10

Completely buried tank
Applicability, 2-37, 2-45

Corrosion protection, 2-46

Diagram, 6-22

Exemption, 2-7, 2-37, 2-43

Leak testing, 7-19, 7-20

Release detection, 3-9

Complex, 2-27, 2-28, 2-29, 2-31, 2-32, 2-51
Definition, 2-27

Compliance date, 1-6, 1-10, **1-11**, 1-12, **1-13**, 1-14, 1-21, 1-26

Condensate, **2-6**, 2-12, 2-24, 2-26, 2-57, 4-60, 5-5

Contact list, **6-4**

Contiguous zone, 1-1, 1-3, 1-19, 2-36

Corrosion protection
Completely buried tank, 1-14, 2-46, **3-8**, 3-9

Piping, 1-14, 2-46, **3-13**, **3-14**, 3-15, 3-16

Cost considerations
Environmental equivalence. *See* Environmental Equivalence, Consideration of costs

Countermeasure, 2-55, 4-24, 4-27, 4-44, 6-1, **6-3**, 7-32

Criteria for State, Local and Regional Oil Removal Contingency Plans, *1-28*, 4-15

Crop oil, 1-21, 2-50

Culverting
Secondary containment example, 4-9, 4-33

Curbing
Secondary containment example, 4-9, 4-24, 4-27, 4-33, 4-53, 4-58, 4-59

Current Good Manufacturing Practice in Manufacturing, Packing or Holding Human Food, *7-15*, *7-16*

Denatured ethanol, **2-7**

Department of Transportation, 1-2, 2-10, 2-27, 2-28, 2-29, 2-30, 2-31, 2-42, 2-50, 7-34

Dike
Secondary containment example, 4-53, 4-58, 4-59, 4-63, 7-74

Diked area
Accumulation of oil. *See* Visible discharge,promptly correct

Discharge
Definition, **2-33**

Disposal of recovered materials, 3-18, 6-1, 6-4, **7-24**, 7-29

DOT. *See* Department of Transportation

Double-walled tank, **4-36**, 4-37, 4-38, 7-43, 7-44

Drainage pond, 4-18

Drainage system
Secondary containment example, 3-6, 3-7, 4-8, 4-32, **4-33**, 4-34, 4-35, 4-39, 4-46, 4-50, 4-53

Drilling
Activity, 2-9, 2-13, 2-48, 4-6, 4-7, 4-63

Drip gas, 2-6

Drip pan
Secondary containment example, 4-10

Dry gas, 2-24, 2-25, 2-26, 2-46, 2-47, 5-5

Edible Oil Regulatory Reform Act, 1-5, 1-9, 2-4

Effluent treatment
System or facility, 4-33, 5-8

Eligibility criteria
Qualified facility. *See* Qualified facility

Qualified oil-filled operational equipment. *See* Qualified oil-filled operational equipment

Emergency generator, 2-47, 5-3, 6-9

Environmental Equivalence
Consideration of costs, **3-22**

Description of, **3-1**

Documentation, **3-22**, 3-23

Integrity testing, 7-43, 7-44, 7-45, 7-46

Executive Order 12777, 1-4, 2-29, 2-42

Facilities Transferring Oil or Hazardous Material in Bulk, *2-30*

Facility Response Plan, 1-2, 1-4, 1-15, 1-16, 2-59, 4-13, 4-41, 4-42, 4-44, 4-51, 4-65, 4-69, 6-2, 6-5, 6-12, 7-53

Farm
Definition, 1-21, **2-14**

Example scenarios, 2-16

Fiberglass reinforced plastic tanks, **7-75**

Fitness for service, 3-14, 7-21, 7-34, 7-73

Flowline maintenance program, **3-17**, 4-16, 7-2, 7-30, 7-32, 7-59

Flow-through process vessel, 1-24, 2-55, 3-5, 4-1, 4-61, 4-63, 4-64, 4-65, 4-66, 5-1, 5-10, 5-12, 5-13, 5-17, 5-18, 7-23, 7-24, 7-59
Alternative measures, 2-58, 3-21, 7-26

Oil production, **2-58**

Freeboard. *See* Sufficient freeboard

Free-water knockout
OWS, 2-58, 4-63, 5-3, 5-10, 5-11, 5-12

FRP. *See* Facility Response Plan

FRP substantial harm criteria
certification of, 1-16, 2-59

Gas pipeline facility, 2-25, 2-26

Gas processing plant, 2-26

Gathering line, 2-32
Definition, 4-15

Intra-facility, 2-32, 2-50, 2-51, 3-16, 3-17, 3-18, 4-15, 4-16, 6-7, 6-10, 6-22, 7-30, 7-31, 7-59

Generator, 1-25, 2-9, 2-45, 4-14

Gun barrel
OWS, 2-58, 4-63, 5-3, 5-10, 5-11, 5-12, 5-14

Gutter
Secondary containment example, 4-9, 4-33

Harmful quantities of oil, **2-33**

Hazardous substance, 1-3, 1-4, 2-3, **2-7**, 6-8, 6-16

Hazardous waste, 2-7, 2-41, 2-44, 4-19

Heater-treater
OWS, 1-24, 2-19, 2-58, 5-10, 5-12, 5-14

Hot-mix asphalt. *See* Asphalt:Hot-mix asphalt

Hybrid inspection program
Minimum components, **7-49**

Industry standards, summary of
API 570, **7-69**

API 653, **7-62**, 7-63

API RP 1110, **7-72**, 7-73

API RP 12R1, **7-68**, 7-69

API RP 574, **7-71**

API RP 575, **7-67**

ASME B31.3, **7-76**, 7-77

ASME B31.4, **7-77**

STI SP001, **7-64**, 7-66

Integrity testing
Baseline, **7-37**, 7-38, 7-40, 7-41

Schedule, 4-41, 5-12, 7-10, 7-13, **7-14**, 7-37, 7-38, 7-56, 7-59

Intermediate Bulk Container, 4-59, 7-66, 7-78

Interstice, 4-37, 7-44, 7-65

Leak testing, 3-9, 3-10, 3-13, 3-14, 3-15, 3-16, 4-41, 7-11, 7-13, 7-19, 7-23, 7-47, 7-49, 7-66, 7-77

Lease, 1-22, 2-10, **2-15**, **2-17**, 2-18, 2-19, 4-15, 4-62

Liner, **1-4**, 4-17, 4-18, *7-18*, 7-43

Manifolded, permanently. *See* Permanently manifolded

Man-made structure, **1-25**, **4-36**

Marine terminal, **2-30**, 2-31

Marine transportation-related facility. *See* Marine Terminal

Milk exemption
3A Sanitary Standards, 1-26

Milk or milk product container, 1-11, **1-26**, **2-51**

Mix container
Pesticide, **1-21**, **2-50**

Mobile facility, 2-11, 2-13, 2-14

Mobile or portable containers, 2-37, 4-59
Facility diagram, 1-22, 4-59, 6-2, 6-5, 6-8, 6-9

Inspection, 7-9, 7-34, 7-42, 7-64, 7-66

Single-use, 7-42

Tank trucks, 2-29

Mobile refueler, 1-10, 1-18, **1-20**, 1-23, 2-29, 2-30, 2-48, 4-1, 4-7, 4-16, 4-51, 4-57, 4-59, **4-60**

Most likely quantity of oil that would be discharged, 4-67, 4-68, 5-13, 6-3, *See* Secondary containment, most like quantity discharged

Motive power, 1-10, 1-18, 1-20, **2-47**, 2-48, 2-49

National Fire Protection Association, 4-36, 4-58, 7-34

National Pollutant Discharge Elimination System, 1-9, 2-46, 4-35, 5-4, 5-14

National Response Center, xvii, xix, 2-33, 4-26, 6-4

Natural disaster, 1-19, 3-33, 3-34, 4-11, 4-12, 4-65, 4-68, 5-13, 7-66

Natural gas, **2-5**, 2-6, **2-24**, 2-25, 2-26, 2-41, 2-44, 5-5

Natural gasoline, 2-6, 2-7

Navigable waters
Definition, 1-1, 1-10, 1-11, 1-25, 2-36

Reasonable expectation of a discharge, 1-21, 1-25, 2-33, 2-34, 2-35, 6-2, 7-14

Ruling, **1-25**

NFPA. *See* National Fire Protection Association

Non-transportation-related facility, **2-27**, **2-28**, 2-30, 2-31

Non-Transportation-Related Tank Truck, **1-23**, 4-1, 4-7, 4-16, 4-57, 4-59, 4-60

Notification requirements, 1-9, **6-4**, 6-5

NPDES. *See* National Pollutant Discharge Elimination System

Nuclear Power Stations, 1-25, 2-45, 2-61

Offshore Facility
Definition, **2-11**

Jurisdiction, **2-42**

Requirements, 4-7, 5-3, 5-13

Oil
Definition, **2-3**

USCG List of, 2-4

Oil Pollution Act of 1990, **1-4**, 1-9, 2-3, 2-17

Oil Pollution Prevention
40 CFR part 112, 1-1, 1-9, 1-15, 1-16, 1-28, 4-37

Oil production facility
Containers. *See* Tank battery

Flow-through process vessels. *See* Flow-through process vessels

Produced water containers. *See* Produced water

Oil recovery
Facility, 2-7, 2-25, 2-26, 2-46, 5-1, 5-2, 5-3, 5-1, 5-5, 5-14, 5-15

Oil recycling
Facility, 2-7, 2-25, 2-26, 2-46, 5-3, 5-5, 5-14

Oil spill contingency plan, 1-18, 1-20, 3-17, 3-26, 4-11, 4-13, 4-14, 4-15, 4-24, 4-27, 4-39, 4-41, 4-42, 4-44, 4-47, 4-48, 4-50, 4-62, 4-65, 4-69, 7-23, 7-31

Oil-filled equipment, 2-24, 2-37, 4-1, 4-8, 4-11, 4-14, 4-34, 4-57, 4-60, 5-3, 5-12, 6-8, 6-10, 6-12, 6-16
Applicability, 2-54

Oil-filled manufacturing equipment, 2-55, 2-56, 4-14, 4-57, 5-15, 6-8, 6-10
Flow-through process vessel. *See* Flow-through process vessel

Oil-filled operational equipment
Definition, 2-55

Overfill prevention
Requirements, 3-4, 3-5, 3-6, 3-10, 3-11, 3-12, 4-37, 4-38, 4-47, 4-54

Standards, 3-9

Overfill protection
Standards, 7-74

Partially buried
tank or container, 2-37, 2-43, 3-10, 7-11, *7-16*

Passive measure
Secondary containment, 4-2, 4-24, 4-26, 4-37, 4-64, 4-67, 4-68

Permanently closed, 1-24, 2-37, 2-40, 2-41, 5-12, 6-7

Permanently manifolded, 4-17

Personnel training, 3-3, 3-22, 3-23, 4-29, 6-3

Pesticide application equipment, **1-21**, 1-22, **2-50**

Produced water
Alternative measures, 2-58, 3-21, **4-66**, 4-67, **4-68**, 7-26, 7-27, 7-28

Applicability, **2-6**, 2-24, 2-25, 2-26, 2-41, 2-46, 5-15

Container, **2-6**, 2-7, 2-57, **2-58**, 4-1, 4-61, 4-65, 5-5, 7-59

Impracticability of secondary containment, 4-68

OWS, 5-10, 5-14

Wastewater treatment, 5-5, 5-14

Production facility
Definition, **2-12**, 2-14, 2-24

Drainage system requirements, 4-35

Example scenarios, 2-17, 2-19, 2-24, 2-25, 6-18

Flowlines and gathering lines, 2-32

OWS, **5-10**

Piping requirements, 4-15

Qualified facility
Appendix G template, 1-23, 4-47, 6-6, 7-9

Deviation from industry standard, 7-46, 7-47

Eligibility criteria, **1-19**

Facility diagram, 6-6

Self-certification, 1-18, 1-19, 3-1, 3-14, 3-23, 4-14, 4-40, 7-9, 7-10

Tier I, 1-23, 6-6, 7-46

Tier II, 1-19, 6-6, 6-22, 7-46

Qualified oil-filled operational equipment
Alternative measures, **4-13**

Eligibility criteria, **1-20**, **4-12**

Qualified facility, **4-14**

Quick drainage system
Secondary containment example, 4-38, 4-54, 4-55, 5-7, 6-3

Rack
Loading/unloading, 1-10, 1-22, 1-23, 1-24, 1-25, 2-28, 2-30, 2-45, 3-3, 3-27, 3-28, 4-1, 4-3, 4-5, 4-16, 4-38, 4-39, 4-51, 4-54, 4-55, 4-56, 4-57, 4-1, 5-7, 6-3, 6-6, 6-12

Railroad car, 2-29, **2-30**, 4-38, 4-61

RCRA. *See* Resource Conservation and Recovery Act

Reconstructed tank, 7-55

Remote impoundment
Secondary containment example, 4-33, 4-46, 4-58

Renewable fuel, 2-7, 2-8

Repair
Definition, **4-38**

Reportable discharge history, 4-11, 4-12

Reporting requirement
Discharge, 4-26, 6-4

SPCC, 2-34, 4-12, 4-65, 5-13, 6-5

Re-rating
Tank. *See* Storage capacity, tank re-rating

Resource Conservation and Recovery Act, 2-7, 2-41, 2-44

Retaining wall

Secondary containment example, 4-9, 4-33

Retention pond
Secondary containment example, 4-10

Saltwater disposal facility, 3-34, 5-3

Secondary containment
Calculation, 4-8, 4-18, 4-20, 4-21, 4-22, 4-23, 4-36, 4-53, 6-13

Example method, **4-9**

Most likely quantity discharged, 4-7, 4-8, 4-25, 4-28, 4-50, 4-51, 4-64, 4-66

Security, 1-19, 1-23, 2-54, **3-19**, 3-20, 3-21

Self-certified Plan. *See* Qualified facility, Self-certification

Sheen, **2-33**

Ships and barges, 2-31, 2-32

Shop-built containers. *See* Shop-fabricated containers

Shop-fabricated containers, 7-18

Single-family residence, heating oil container
Exemption, 1-22, 2-10, 2-21, 2-23, **2-49**

Sorbent
Secondary containment example, **4-10**, 4-24, 4-25, 4-26, 4-27, 4-28, 4-34, 4-50

SPCC Plan review, 1-9, 1-18

Spill diversion pond
Secondary containment example, 4-10

Spill mat
Secondary containment example, 4-9, 4-34

Storage capacity, **2-39**, 2-40, 7-53
Alteration, 2-38, 2-39, 2-40, 7-52, 7-53, 7-54, 7-55

Applicability, 1-2

Container, **2-37**, 2-38, 2-39, 2-40, 7-52

Facility, 1-6, 1-19, 1-21, 1-22, 1-23, 1-27, 2-1, 2-2, 2-6, 2-7, 2-10, 2-16, 2-17, 2-21, 2-22, 2-23, 2-24, 2-26, 2-27, 2-29, 2-30, **2-37**, 2-40, 2-46, 2-49, 2-50, 2-51, 2-52, 2-53, 2-58, 4-45, 5-2, 5-3, 5-5, 5-8, 5-12, 5-18, 6-2

Tank re-rating, **2-39**, 7-52

Sufficient freeboard, 2-57, 4-17, **4-19**, 4-20, **4-21**, 4-58, 4-59, 4-61, 4-64, 4-66, 5-8, 6-3
Role of EPA Inspector, 4-23

Sufficiently impervious, 4-2, **4-29**, 4-30, 4-36, 4-58
Role of EPA Inspector, 4-31

Sump
Secondary containment example, 7-32

Synthetic oil, 2-4, 2-7

Tank battery, 2-12, 2-14, 2-17, 2-18, 2-19, 2-26, 2-32, **2-57**, 2-58, 4-15, 4-51, 4-61, 4-62, 4-64, 4-65, 6-18

Tank tightness testing. *See* Leak testing

Technical Standards and Corrective Action Requirements for Owners and Operators of Underground Storage Tanks
40 CFR part 280, 2-43

Transformer, 2-9, 2-23, 2-37, 2-55, 3-7, 4-8, 4-27, 5-12, 6-6, 6-16

Transportation of Hazardous Liquids by Pipeline
40 CFR part 195, 2-51

Transportation of Natural and Other Gas by Pipeline
49 CFR part 192, 2-51

Underground storage tank, 1-18, 2-7, 2-14, **2-43**, 2-45, 2-49, 3-9, 3-13, 6-6, **6-9**

United States Coast Guard, 2-4, 2-10, 2-28, 2-30, 2-31

USCG. *See* United States Coast Guard

UST. *See* Underground storage tank

Valve
Flapper design, 3-6

Open-and-closed design, 3-6

Vandalism, 3-19, 3-20, 3-21

Vaulted tank, 2-45, 2-54, 4-36, 4-37, 6-9, 7-11

Vegetable oil, 1-5, 1-10, 1-18, 1-21, 1-24, 2-4, **2-5**, 2-44, 3-6, 3-12, 3-21, 4-14, 4-37, 4-59, 5-3, 7-2, 7-10, 7-15

Vessel. *See* Ships and barges

Visible discharge
Promptly correct, **7-14**

Wastewater treatment exemption, **5-14**

Weir
Secondary containment example, 4-9, 4-33

Wellhead, 2-6, 2-12, 2-17, 2-18, 2-19, 2-24, 2-25, 2-57, 4-15, 4-62

Wet gas, 2-24, 2-25, 3-8, 5-5

Wind turbine, **1-25**, 2-55

Workover
Activity, 2-13, 2-14, 2-42, 2-48, 4-6, 4-7, 4-63

Written commitment of manpower, equipment, and materials, 1-18, 1-20, 2-57, 4-13, 4-14, 4-15, 4-27, 4-41, **4-42**, 4-43, 4-65, 4-69, 7-23, 7-31

Appendix A: CWA 311(j)(1)(c)

CWA §§ 311(j)(1)(c)

Summary:
The President is authorized to issue regulations establishing procedures, methods, equipment, and other requirements to prevent discharges of oil from vessels and facilities.

Rule Text:
(j) National Response System

(1) In general

Consistent with the National Contingency Plan required by subsection (c)(2) of this section, as soon as practicable after October 18, 1972, and from time to time thereafter, the President shall issue regulations consistent with maritime safety and with marine and navigation laws

(c)

establishing procedures, methods, and equipment and other requirements for equipment to prevent discharges of oil and hazardous substances from vessels and from onshore facilities and off shore facilities, and to contain such discharges…

Appendix B: Selected Regulations

- 40 CFR part 109: Criteria for State, Local and Regional Oil Removal Contingency Plans
- 40 CFR part 110: Discharge of Oil
- 40 CFR part 112: Oil Pollution Prevention

Copies of the regulations provided in this appendix are current as of the publication of this guidance. Since the regulations are subject to change, the appendix is provided for informational purposes only.

The Federal Register – the official daily publication for rules, proposed rules, and notices of federal agencies and organizations – is available electronically from the U.S. Government Printing Office Web site at http://www.gpoaccess.gov/fr/.

General and permanent rules published in the Federal Register are codified in the Code of Federal Regulations (CFR), available electronically at http://www.gpoaccess.gov/cfr/. Each volume of the CFR is updated once each calendar year and is issued on a quarterly basis.

For a more frequently updated version of the CFR, refer to the Electronic Code of Federal Regulations (e-CFR) at http://www.gpoaccess.gov/ecfr/. The e-CFR is updated daily but is not an official legal edition of the CFR.

Inspectors implementing the SPCC program should always consult the aforementioned resources (or their equivalent) to obtain the current version of the regulations.

engine on a public vessel) and any discharges of such oil accumulated in the bilges of a vessel discharged in compliance with MARPOL 73/78, Annex I, as provided in 33 CFR part 151, subpart A;

(b) Other discharges of oil permitted under MARPOL 73/78, Annex I, as provided in 33 CFR part 151, subpart A; and

(c) Any discharge of oil explicitly permitted by the Administrator in connection with research, demonstration projects, or studies relating to the prevention, control, or abatement of oil pollution.

[61 FR 7421, Feb. 28, 1996]

§ 110.6 Notice.

Any person in charge of a vessel or of an onshore or offshore facility shall, as soon as he or she has knowledge of any discharge of oil from such vessel or facility in violation of section 311(b)(3) of the Act, immediately notify the National Response Center (NRC) (800–424–8802; in the Washington, DC metropolitan area, 202–426–2675). If direct reporting to the NRC is not practicable, reports may be made to the Coast Guard or EPA predesignated On-Scene Coordinator (OSC) for the geographic area where the discharge occurs. All such reports shall be promptly relayed to the NRC. If it is not possible to notify the NRC or the predesignated OCS immediately, reports may be made immediately to the nearest Coast Guard unit, provided that the person in charge of the vessel or onshore or offshore facility notifies the NRC as soon as possible. The reports shall be made in accordance with such procedures as the Secretary of Transportation may prescribe. The procedures for such notice are set forth in U.S. Coast Guard regulations, 33 CFR part 153, subpart B and in the National Oil and Hazardous Substances Pollution Contingency Plan, 40 CFR part 300, subpart E.

(Approved by the Office of Management and Budget under control number 2050–0046)

[52 FR 10719, Apr. 2, 1987. Redesignated and amended at 61 FR 7421, Feb. 28, 1996; 61 FR 14032, Mar. 29, 1996]

PART 112—OIL POLLUTION PREVENTION

Subpart A—Applicability, Definitions, and General Requirements For All Facilities and All Types of Oils

Sec.
112.1 General applicability.
112.2 Definitions.
112.3 Requirement to prepare and implement a Spill Prevention, Control, and Countermeasure Plan.
112.4 Amendment of Spill Prevention, Control, and Countermeasure Plan by Regional Administrator.
112.5 Amendment of Spill Prevention, Control, and Countermeasure Plan by owners or operators.
112.6 Qualified Facility Plan Requirements.
112.7 General requirements for Spill Prevention, Control, and Countermeasure Plans.

Subpart B—Requirements for Petroleum Oils and Non-Petroleum Oils, Except Animal Fats and Oils and Greases, and Fish and Marine Mammal Oils; and Vegetable Oils (Including Oils from Seeds, Nuts, Fruits, and Kernels)

112.8 Spill Prevention, Control, and Countermeasure Plan requirements for onshore facilities (excluding production facilities).
112.9 Spill Prevention, Control, and Countermeasure Plan Requirements for onshore oil production facilities (excluding drilling and workover facilities).
112.10 Spill Prevention, Control, and Countermeasure Plan requirements for onshore oil drilling and workover facilities.
112.11 Spill Prevention, Control, and Countermeasure Plan requirements for offshore oil drilling, production, or workover facilities.

Subpart C—Requirements for Animal Fats and Oils and Greases, and Fish and Marine Mammal Oils; and for Vegetable Oils, Including Oils from Seeds, Nuts, Fruits and Kernels

112.12 Spill Prevention, Control, and Countermeasure Plan requirements.
112.13–112.15 [Reserved]

Subpart D—Response Requirements

112.20 Facility response plans.
112.21 Facility response training and drills/exercises.
APPENDIX A TO PART 112—MEMORANDUM OF UNDERSTANDING BETWEEN THE SECRETARY

OF TRANSPORTATION AND THE ADMINISTRATOR OF THE ENVIRONMENTAL PROTECTION AGENCY
APPENDIX B TO PART 112—MEMORANDUM OF UNDERSTANDING AMONG THE SECRETARY OF THE INTERIOR, SECRETARY OF TRANSPORTATION, AND ADMINISTRATOR OF THE ENVIRONMENTAL PROTECTION AGENCY
APPENDIX C TO PART 112—SUBSTANTIAL HARM CRITERIA
APPENDIX D TO PART 112—DETERMINATION OF A WORST CASE DISCHARGE PLANNING VOLUME
APPENDIX E TO PART 112—DETERMINATION AND EVALUATION OF REQUIRED RESPONSE RESOURCES FOR FACILITY RESPONSE PLANS
APPENDIX F TO PART 112—FACILITY-SPECIFIC RESPONSE PLAN
APPENDIX G TO PART 112—TIER I QUALIFIED FACILITY SPCC PLAN

AUTHORITY: 33 U.S.C. 1251 *et seq.;* 33 U.S.C. 2720; E.O. 12777 (October 18, 1991), 3 CFR, 1991 Comp., p. 351.

SOURCE: 38 FR 34165, Dec. 11, 1973, unless otherwise noted.

EDITORIAL NOTE: Nomenclature changes to part 112 appear at 65 FR 40798, June 30, 2000.

Subpart A—Applicability, Definitions, and General Requirements for All Facilities and All Types of Oils

SOURCE: 67 FR 47140, July 17, 2002, unless otherwise noted.

§ 112.1 General applicability.

(a)(1) This part establishes procedures, methods, equipment, and other requirements to prevent the discharge of oil from non-transportation-related onshore and offshore facilities into or upon the navigable waters of the United States or adjoining shorelines, or into or upon the waters of the contiguous zone, or in connection with activities under the Outer Continental Shelf Lands Act or the Deepwater Port Act of 1974, or that may affect natural resources belonging to, appertaining to, or under the exclusive management authority of the United States (including resources under the Magnuson Fishery Conservation and Management Act).

(2) As used in this part, words in the singular also include the plural and words in the masculine gender also include the feminine and vice versa, as the case may require.

(b) Except as provided in paragraph (d) of this section, this part applies to any owner or operator of a non-transportation-related onshore or offshore facility engaged in drilling, producing, gathering, storing, processing, refining, transferring, distributing, using, or consuming oil and oil products, which due to its location, could reasonably be expected to discharge oil in quantities that may be harmful, as described in part 110 of this chapter, into or upon the navigable waters of the United States or adjoining shorelines, or into or upon the waters of the contiguous zone, or in connection with activities under the Outer Continental Shelf Lands Act or the Deepwater Port Act of 1974, or that may affect natural resources belonging to, appertaining to, or under the exclusive management authority of the United States (including resources under the Magnuson Fishery Conservation and Management Act) that has oil in:

(1) Any aboveground container;

(2) Any completely buried tank as defined in § 112.2;

(3) Any container that is used for standby storage, for seasonal storage, or for temporary storage, or not otherwise ''permanently closed'' as defined in § 112.2;

(4) Any ''bunkered tank'' or ''partially buried tank'' as defined in § 112.2, or any container in a vault, each of which is considered an aboveground storage container for purposes of this part.

(c) As provided in section 313 of the Clean Water Act (CWA), departments, agencies, and instrumentalities of the Federal government are subject to this part to the same extent as any person.

(d) Except as provided in paragraph (f) of this section, this part does not apply to:

(1) The owner or operator of any facility, equipment, or operation that is not subject to the jurisdiction of the Environmental Protection Agency (EPA) under section 311(j)(1)(C) of the CWA, as follows:

(i) Any onshore or offshore facility, that due to its location, could not reasonably be expected to have a discharge as described in paragraph (b) of

this section. This determination must be based solely upon consideration of the geographical and location aspects of the facility (such as proximity to navigable waters or adjoining shorelines, land contour, drainage, etc.) and must exclude consideration of man-made features such as dikes, equipment or other structures, which may serve to restrain, hinder, contain, or otherwise prevent a discharge as described in paragraph (b) of this section.

(ii) Any equipment, or operation of a vessel or transportation-related onshore or offshore facility which is subject to the authority and control of the U.S. Department of Transportation, as defined in the Memorandum of Understanding between the Secretary of Transportation and the Administrator of EPA, dated November 24, 1971 (appendix A of this part).

(iii) Any equipment, or operation of a vessel or onshore or offshore facility which is subject to the authority and control of the U.S. Department of Transportation or the U.S. Department of the Interior, as defined in the Memorandum of Understanding between the Secretary of Transportation, the Secretary of the Interior, and the Administrator of EPA, dated November 8, 1993 (appendix B of this part).

(2) Any facility which, although otherwise subject to the jurisdiction of EPA, meets both of the following requirements:

(i) The completely buried storage capacity of the facility is 42,000 U.S. gallons or less of oil. For purposes of this exemption, the completely buried storage capacity of a facility excludes the capacity of a completely buried tank, as defined in § 112.2, and connected underground piping, underground ancillary equipment, and containment systems, that is currently subject to all of the technical requirements of part 280 of this chapter or all of the technical requirements of a State program approved under part 281 of this chapter, or the capacity of any underground oil storage tanks deferred under 40 CFR part 280 that supply emergency diesel generators at a nuclear power generation facility licensed by the Nuclear Regulatory Commission and subject to any Nuclear Regulatory Commission provision regarding design and quality criteria, including, but not limited to, 10 CFR part 50. The completely buried storage capacity of a facility also excludes the capacity of a container that is ''permanently closed,'' as defined in § 112.2 and the capacity of intra-facility gathering lines subject to the regulatory requirements of 49 CFR part 192 or 195.

(ii) The aggregate aboveground storage capacity of the facility is 1,320 U.S. gallons or less of oil. For the purposes of this exemption, only containers with a capacity of 55 U.S. gallons or greater are counted. The aggregate aboveground storage capacity of a facility excludes:

(A) The capacity of a container that is ''permanently closed'' as defined in § 112.2;

(B) The capacity of a ''motive power container'' as defined in § 112.2;

(C) The capacity of hot-mix asphalt or any hot-mix asphalt container;

(D) The capacity of a container for heating oil used solely at a single-family residence;

(E) The capacity of pesticide application equipment and related mix containers.

(F) The capacity of any milk and milk product container and associated piping and appurtenances.

(3) Any offshore oil drilling, production, or workover facility that is subject to the notices and regulations of the Minerals Management Service, as specified in the Memorandum of Understanding between the Secretary of Transportation, the Secretary of the Interior, and the Administrator of EPA, dated November 8, 1993 (appendix B of this part).

(4) Any completely buried storage tank, as defined in § 112.2, and connected underground piping, underground ancillary equipment, and containment systems, at any facility, that is subject to all of the technical requirements of part 280 of this chapter or a State program approved under part 281 of this chapter, or any underground oil storage tanks including below-grade vaulted tanks, deferred under 40 CFR part 280, as originally promulgated, that supply emergency diesel generators at a nuclear power generation facility licensed by the Nuclear Regulatory Commission, provided

that such a tank is subject to any Nuclear Regulatory Commission provision regarding design and quality criteria, including, but not limited to, 10 CFR part 50. Such emergency generator tanks must be marked on the facility diagram as provided in § 112.7(a)(3), if the facility is otherwise subject to this part.

(5) Any container with a storage capacity of less than 55 gallons of oil.

(6) Any facility or part thereof used exclusively for wastewater treatment and not used to satisfy any requirement of this part. The production, recovery, or recycling of oil is not wastewater treatment for purposes of this paragraph.

(7) Any ''motive power container,'' as defined in § 112.2. The transfer of fuel or other oil into a motive power container at an otherwise regulated facility is not eligible for this exemption.

(8) Hot-mix asphalt, or any hot-mix asphalt container.

(9) Any container for heating oil used solely at a single-family residence.

(10) Any pesticide application equipment or related mix containers.

(11) Intra-facility gathering lines subject to the regulatory requirements of 49 CFR part 192 or 195, except that such a line's location must be identified and marked as ''exempt'' on the facility diagram as provided in § 112.7(a)(3), if the facility is otherwise subject to this part.

(12) Any milk and milk product container and associated piping and appurtenances.

(e) This part establishes requirements for the preparation and implementation of Spill Prevention, Control, and Countermeasure (SPCC) Plans. SPCC Plans are designed to complement existing laws, regulations, rules, standards, policies, and procedures pertaining to safety standards, fire prevention, and pollution prevention rules. The purpose of an SPCC Plan is to form a comprehensive Federal/State spill prevention program that minimizes the potential for discharges. The SPCC Plan must address all relevant spill prevention, control, and countermeasures necessary at the specific facility. Compliance with this part does not in any way relieve the owner or operator of an onshore or an offshore facility from compliance with other Federal, State, or local laws.

(f) Notwithstanding paragraph (d) of this section, the Regional Administrator may require that the owner or operator of any facility subject to the jurisdiction of EPA under section 311(j) of the CWA prepare and implement an SPCC Plan, or any applicable part, to carry out the purposes of the CWA.

(1) Following a preliminary determination, the Regional Administrator must provide a written notice to the owner or operator stating the reasons why he must prepare an SPCC Plan, or applicable part. The Regional Administrator must send such notice to the owner or operator by certified mail or by personal delivery. If the owner or operator is a corporation, the Regional Administrator must also mail a copy of such notice to the registered agent, if any and if known, of the corporation in the State where the facility is located.

(2) Within 30 days of receipt of such written notice, the owner or operator may provide information and data and may consult with the Agency about the need to prepare an SPCC Plan, or applicable part.

(3) Within 30 days following the time under paragraph (b)(2) of this section within which the owner or operator may provide information and data and consult with the Agency about the need to prepare an SPCC Plan, or applicable part, the Regional Administrator must make a final determination regarding whether the owner or operator is required to prepare and implement an SPCC Plan, or applicable part. The Regional Administrator must send the final determination to the owner or operator by certified mail or by personal delivery. If the owner or operator is a corporation, the Regional Administrator must also mail a copy of the final determination to the registered agent, if any and if known, of the corporation in the State where the facility is located.

(4) If the Regional Administrator makes a final determination that an SPCC Plan, or applicable part, is necessary, the owner or operator must prepare the Plan, or applicable part, within six months of that final determination and implement the Plan, or applicable part, as soon as possible, but not

later than one year after the Regional Administrator has made a final determination.

(5) The owner or operator may appeal a final determination made by the Regional Administrator requiring preparation and implementation of an SPCC Plan, or applicable part, under this paragraph. The owner or operator must make the appeal to the Administrator of EPA within 30 days of receipt of the final determination under paragraph (b)(3) of this section from the Regional Administrator requiring preparation and/or implementation of an SPCC Plan, or applicable part. The owner or operator must send a complete copy of the appeal to the Regional Administrator at the time he makes the appeal to the Administrator. The appeal must contain a clear and concise statement of the issues and points of fact in the case. In the appeal, the owner or operator may also provide additional information. The additional information may be from any person. The Administrator may request additional information from the owner or operator. The Administrator must render a decision within 60 days of receiving the appeal or additional information submitted by the owner or operator and must serve the owner or operator with the decision made in the appeal in the manner described in paragraph (f)(1) of this section.

[67 FR 47140, July 17, 2002, as amended at 71 FR 77290, Dec. 26, 2006; 73 FR 74300, Dec. 5, 2008; 74 FR 58809, Nov. 13, 2009; 76 FR 21660, Apr. 18, 2011]

§ 112.2 Definitions.

For the purposes of this part:

Adverse weather means weather conditions that make it difficult for response equipment and personnel to clean up or remove spilled oil, and that must be considered when identifying response systems and equipment in a response plan for the applicable operating environment. Factors to consider include significant wave height as specified in appendix E to this part (as appropriate), ice conditions, temperatures, weather-related visibility, and currents within the area in which the systems or equipment is intended to function.

Alteration means any work on a container involving cutting, burning, welding, or heating operations that changes the physical dimensions or configuration of the container.

Animal fat means a non-petroleum oil, fat, or grease of animal, fish, or marine mammal origin.

Breakout tank means a container used to relieve surges in an oil pipeline system or to receive and store oil transported by a pipeline for reinjection and continued transportation by pipeline.

Bulk storage container means any container used to store oil. These containers are used for purposes including, but not limited to, the storage of oil prior to use, while being used, or prior to further distribution in commerce. Oil-filled electrical, operating, or manufacturing equipment is not a bulk storage container.

Bunkered tank means a container constructed or placed in the ground by cutting the earth and re-covering the container in a manner that breaks the surrounding natural grade, or that lies above grade, and is covered with earth, sand, gravel, asphalt, or other material. A bunkered tank is considered an aboveground storage container for purposes of this part.

Completely buried tank means any container completely below grade and covered with earth, sand, gravel, asphalt, or other material. Containers in vaults, bunkered tanks, or partially buried tanks are considered aboveground storage containers for purposes of this part.

Complex means a facility possessing a combination of transportation-related and non-transportation-related components that is subject to the jurisdiction of more than one Federal agency under section 311(j) of the CWA.

Contiguous zone means the zone established by the United States under Article 24 of the Convention of the Territorial Sea and Contiguous Zone, that is contiguous to the territorial sea and that extends nine miles seaward from the outer limit of the territorial area.

Contract or other approved means means:

(1) A written contractual agreement with an oil spill removal organization that identifies and ensures the availability of the necessary personnel and

equipment within appropriate response times; and/or

(2) A written certification by the owner or operator that the necessary personnel and equipment resources, owned or operated by the facility owner or operator, are available to respond to a discharge within appropriate response times; and/or

(3) Active membership in a local or regional oil spill removal organization that has identified and ensures adequate access through such membership to necessary personnel and equipment to respond to a discharge within appropriate response times in the specified geographic area; and/or

(4) Any other specific arrangement approved by the Regional Administrator upon request of the owner or operator.

Discharge includes, but is not limited to, any spilling, leaking, pumping, pouring, emitting, emptying, or dumping of oil, but excludes discharges in compliance with a permit under section 402 of the CWA; discharges resulting from circumstances identified, reviewed, and made a part of the public record with respect to a permit issued or modified under section 402 of the CWA, and subject to a condition in such permit; or continuous or anticipated intermittent discharges from a point source, identified in a permit or permit application under section 402 of the CWA, that are caused by events occurring within the scope of relevant operating or treatment systems. For purposes of this part, the term discharge shall not include any discharge of oil that is authorized by a permit issued under section 13 of the River and Harbor Act of 1899 (33 U.S.C. 407).

Facility means any mobile or fixed, onshore or offshore building, property, parcel, lease, structure, installation, equipment, pipe, or pipeline (other than a vessel or a public vessel) used in oil well drilling operations, oil production, oil refining, oil storage, oil gathering, oil processing, oil transfer, oil distribution, and oil waste treatment, or in which oil is used, as described in appendix A to this part. The boundaries of a facility depend on several site-specific factors, including but not limited to, the ownership or operation of buildings, structures, and equipment on the same site and types of activity at the site. Contiguous or non-contiguous buildings, properties, parcels, leases, structures, installations, pipes, or pipelines under the ownership or operation of the same person may be considered separate facilities. Only this definition governs whether a facility is subject to this part.

Farm means a facility on a tract of land devoted to the production of crops or raising of animals, including fish, which produced and sold, or normally would have produced and sold, $1,000 or more of agricultural products during a year.

Fish and wildlife and sensitive environments means areas that may be identified by their legal designation or by evaluations of Area Committees (for planning) or members of the Federal On-Scene Coordinator's spill response structure (during responses). These areas may include wetlands, National and State parks, critical habitats for endangered or threatened species, wilderness and natural resource areas, marine sanctuaries and estuarine reserves, conservation areas, preserves, wildlife areas, wildlife refuges, wild and scenic rivers, recreational areas, national forests, Federal and State lands that are research national areas, heritage program areas, land trust areas, and historical and archaeological sites and parks. These areas may also include unique habitats such as aquaculture sites and agricultural surface water intakes, bird nesting areas, critical biological resource areas, designated migratory routes, and designated seasonal habitats.

Injury means a measurable adverse change, either long- or short-term, in the chemical or physical quality or the viability of a natural resource resulting either directly or indirectly from exposure to a discharge, or exposure to a product of reactions resulting from a discharge.

Loading/unloading rack means a fixed structure (such as a platform, gangway) necessary for loading or unloading a tank truck or tank car, which is

located at a facility subject to the requirements of this part. A loading/unloading rack includes a loading or unloading arm, and may include any combination of the following: piping assemblages, valves, pumps, shut-off devices, overfill sensors, or personnel safety devices.

Maximum extent practicable means within the limitations used to determine oil spill planning resources and response times for on-water recovery, shoreline protection, and cleanup for worst case discharges from onshore non-transportation-related facilities in adverse weather. It includes the planned capability to respond to a worst case discharge in adverse weather, as contained in a response plan that meets the requirements in § 112.20 or in a specific plan approved by the Regional Administrator.

Mobile refueler means a bulk storage container onboard a vehicle or towed, that is designed or used solely to store and transport fuel for transfer into or from an aircraft, motor vehicle, locomotive, vessel, ground service equipment, or other oil storage container.

Motive power container means any onboard bulk storage container used primarily to power the movement of a motor vehicle, or ancillary onboard oil-filled operational equipment. An onboard bulk storage container which is used to store or transfer oil for further distribution is not a motive power container. The definition of motive power container does not include oil drilling or workover equipment, including rigs.

Navigable waters of the United States means ''navigable waters'' as defined in section 502(7) of the FWPCA, and includes:

(1) All navigable waters of the United States, as defined in judicial decisions prior to passage of the 1972 Amendments to the FWPCA (Pub. L. 92–500), and tributaries of such waters;

(2) Interstate waters;

(3) Intrastate lakes, rivers, and streams which are utilized by interstate travelers for recreational or other purposes; and

(4) Intrastate lakes, rivers, and streams from which fish or shellfish are taken and sold in interstate commerce.

Non-petroleum oil means oil of any kind that is not petroleum-based, including but not limited to: Fats, oils, and greases of animal, fish, or marine mammal origin; and vegetable oils, including oils from seeds, nuts, fruits, and kernels.

Offshore facility means any facility of any kind (other than a vessel or public vessel) located in, on, or under any of the navigable waters of the United States, and any facility of any kind that is subject to the jurisdiction of the United States and is located in, on, or under any other waters.

Oil means oil of any kind or in any form, including, but not limited to: fats, oils, or greases of animal, fish, or marine mammal origin; vegetable oils, including oils from seeds, nuts, fruits, or kernels; and, other oils and greases, including petroleum, fuel oil, sludge, synthetic oils, mineral oils, oil refuse, or oil mixed with wastes other than dredged spoil.

Oil-filled operational equipment means equipment that includes an oil storage container (or multiple containers) in which the oil is present solely to support the function of the apparatus or the device. Oil-filled operational equipment is not considered a bulk storage container, and does not include oil-filled manufacturing equipment (flow-through process). Examples of oil-filled operational equipment include, but are not limited to, hydraulic systems, lubricating systems (*e.g.*, those for pumps, compressors and other rotating equipment, including pumpjack lubrication systems), gear boxes, machining coolant systems, heat transfer systems, transformers, circuit breakers, electrical switches, and other systems containing oil solely to enable the operation of the device.

Oil Spill Removal Organization means an entity that provides oil spill response resources, and includes any for-profit or not-for-profit contractor, cooperative, or in-house response resources that have been established in a geographic area to provide required response resources.

Onshore facility means any facility of any kind located in, on, or under any land within the United States, other than submerged lands.

Owner or operator means any person owning or operating an onshore facility or an offshore facility, and in the case of any abandoned offshore facility, the person who owned or operated or maintained the facility immediately prior to such abandonment.

Partially buried tank means a storage container that is partially inserted or constructed in the ground, but not entirely below grade, and not completely covered with earth, sand, gravel, asphalt, or other material. A partially buried tank is considered an aboveground storage container for purposes of this part.

Permanently closed means any container or facility for which:

(1) All liquid and sludge has been removed from each container and connecting line; and

(2) All connecting lines and piping have been disconnected from the container and blanked off, all valves (except for ventilation valves) have been closed and locked, and conspicuous signs have been posted on each container stating that it is a permanently closed container and noting the date of closure.

Person includes an individual, firm, corporation, association, or partnership.

Petroleum oil means petroleum in any form, including but not limited to crude oil, fuel oil, mineral oil, sludge, oil refuse, and refined products.

Produced water container means a storage container at an oil production facility used to store the produced water after initial oil/water separation, and prior to reinjection, beneficial reuse, discharge, or transfer for disposal.

Production facility means all structures (including but not limited to wells, platforms, or storage facilities), piping (including but not limited to flowlines or intra-facility gathering lines), or equipment (including but not limited to workover equipment, separation equipment, or auxiliary non-transportation-related equipment) used in the production, extraction, recovery, lifting, stabilization, separation or treating of oil (including condensate), or associated storage or measurement, and is located in an oil or gas field, at a facility. This definition governs whether such structures, piping, or equipment are subject to a specific section of this part.

Regional Administrator means the Regional Administrator of the Environmental Protection Agency, in and for the Region in which the facility is located.

Repair means any work necessary to maintain or restore a container to a condition suitable for safe operation, other than that necessary for ordinary, day-to-day maintenance to maintain the functional integrity of the container and that does not weaken the container.

Spill Prevention, Control, and Countermeasure Plan; SPCC Plan, or Plan means the document required by §112.3 that details the equipment, workforce, procedures, and steps to prevent, control, and provide adequate countermeasures to a discharge.

Storage capacity of a container means the shell capacity of the container.

Transportation-related and non-transportation-related, as applied to an onshore or offshore facility, are defined in the Memorandum of Understanding between the Secretary of Transportation and the Administrator of the Environmental Protection Agency, dated November 24, 1971, (appendix A of this part).

United States means the States, the District of Columbia, the Commonwealth of Puerto Rico, the Commonwealth of the Northern Mariana Islands, Guam, American Samoa, the U.S. Virgin Islands, and the Pacific Island Governments.

Vegetable oil means a non-petroleum oil or fat of vegetable origin, including but not limited to oils and fats derived from plant seeds, nuts, fruits, and kernels.

Vessel means every description of watercraft or other artificial contrivance used, or capable of being used, as a means of transportation on water, other than a public vessel.

Wetlands means those areas that are inundated or saturated by surface or groundwater at a frequency or duration sufficient to support, and that under normal circumstances do support, a prevalence of vegetation typically adapted for life in saturated soil conditions. Wetlands generally include playa

lakes, swamps, marshes, bogs, and similar areas such as sloughs, prairie potholes, wet meadows, prairie river overflows, mudflats, and natural ponds.

Worst case discharge for an onshore non-transportation-related facility means the largest foreseeable discharge in adverse weather conditions as determined using the worksheets in appendix D to this part.

[67 FR 47140, July 17, 2002, as amended at 71 FR 77290, Dec. 26, 2006; 73 FR 71943, Nov. 26, 2008; 73 FR 74300, Dec. 5, 2008]

§ 112.3 Requirement to prepare and implement a Spill Prevention, Control, and Countermeasure Plan.

The owner or operator or an onshore or offshore facility subject to this section must prepare in writing and implement a Spill Prevention Control and Countermeasure Plan (hereafter ''SPCC Plan'' or ''Plan''),'' in accordance with § 112.7 and any other applicable section of this part.

(a)(1) Except as otherwise provided in this section, if your facility, or mobile or portable facility, was in operation on or before August 16, 2002, you must maintain your Plan, but must amend it, if necessary to ensure compliance with this part, and implement the amended Plan no later than November 10, 2011. If such a facility becomes operational after August 16, 2002, through November 10, 2011, and could reasonably be expected to have a discharge as described in § 112.1(b), you must prepare and implement a Plan on or before November 10, 2011. If such a facility (excluding oil production facilities) becomes operational after November 10, 2011, and could reasonably be expected to have a discharge as described in § 112.1(b), you must prepare and implement a Plan before you begin operations. You are not required to prepare a new Plan each time you move a mobile or portable facility to a new site; the Plan may be general. When you move the mobile or portable facility, you must locate and install it using the discharge prevention practices outlined in the Plan for the facility. The Plan is applicable only while the mobile or portable facility is in a fixed (non-transportation) operating mode.

(2) If your drilling, production or workover facility, including a mobile or portable facility, is offshore or has an offshore component; or your onshore facility is required to have and submit a Facility Response Plan pursuant to 40 CFR 112.20(a), and was in operation on or before August 16, 2002, you must maintain your Plan, but must amend it, if necessary to ensure compliance with this part, and implement the amended Plan no later than November 10, 2010. If such a facility becomes operational after August 16, 2002, through November 10, 2010, and could reasonably be expected to have a discharge as described in § 112.1(b), you must prepare and implement a Plan on or before November 10, 2010. If such a facility (excluding oil production facilities) becomes operational after November 10, 2010, and could reasonably be expected to have a discharge as described in § 112.1(b), you must prepare and implement a Plan before you begin operations. You are not required to prepare a new Plan each time you move a mobile or portable facility to a new site; the Plan may be general. When you move the mobile or portable facility, you must locate and install it using the discharge prevention practices outlined in the Plan for the facility. The Plan is applicable only while the mobile or portable facility is in a fixed (non-transportation) operating mode.

(3) If your farm, as defined in § 112.2, was in operation on or before August 16, 2002, you must maintain your Plan, but must amend it, if necessary to ensure compliance with this part, and implement the amended Plan on or before May 10, 2013. If your farm becomes operational after August 16, 2002, through May 10, 2013, and could reasonably be expected to have a discharge as described in § 112.1(b), you must prepare and implement a Plan on or before May 10, 2013. If your farm becomes operational after May 10, 2013, and could reasonably be expected to have a discharge as described in § 112.1(b), you must prepare and implement a Plan before you begin operations.

(b) If your oil production facility as described in paragraph (a)(1) of this section becomes operational after November 10, 2011, or as described in paragraph (a)(2) of this section becomes operational after November 10, 2010,

and could reasonably be expected to have a discharge as described in §112.1(b), you must prepare and implement a Plan within six months after you begin operations.

(c) [Reserved]

(d) Except as provided in §112.6, a licensed Professional Engineer must review and certify a Plan for it to be effective to satisfy the requirements of this part.

(1) By means of this certification the Professional Engineer attests:

(i) That he is familiar with the requirements of this part ;

(ii) That he or his agent has visited and examined the facility;

(iii) That the Plan has been prepared in accordance with good engineering practice, including consideration of applicable industry standards, and with the requirements of this part;

(iv) That procedures for required inspections and testing have been established; and

(v) That the Plan is adequate for the facility.

(vi) That, if applicable, for a produced water container subject to §112.9(c)(6), any procedure to minimize the amount of free-phase oil is designed to reduce the accumulation of free-phase oil and the procedures and frequency for required inspections, maintenance and testing have been established and are described in the Plan.

(2) Such certification shall in no way relieve the owner or operator of a facility of his duty to prepare and fully implement such Plan in accordance with the requirements of this part.

(e) If you are the owner or operator of a facility for which a Plan is required under this section, you must:

(1) Maintain a complete copy of the Plan at the facility if the facility is normally attended at least four hours per day, or at the nearest field office if the facility is not so attended, and

(2) Have the Plan available to the Regional Administrator for on-site review during normal working hours.

(f) *Extension of time.* (1) The Regional Administrator may authorize an extension of time for the preparation and full implementation of a Plan, or any amendment thereto, beyond the time permitted for the preparation, implementation, or amendment of a Plan under this part, when he finds that the owner or operator of a facility subject to this section, cannot fully comply with the requirements as a result of either nonavailability of qualified personnel, or delays in construction or equipment delivery beyond the control and without the fault of such owner or operator or his agents or employees.

(2) If you are an owner or operator seeking an extension of time under paragraph (f)(1) of this section, you may submit a written extension request to the Regional Administrator. Your request must include:

(i) A full explanation of the cause for any such delay and the specific aspects of the Plan affected by the delay;

(ii) A full discussion of actions being taken or contemplated to minimize or mitigate such delay; and

(iii) A proposed time schedule for the implementation of any corrective actions being taken or contemplated, including interim dates for completion of tests or studies, installation and operation of any necessary equipment, or other preventive measures. In addition you may present additional oral or written statements in support of your extension request.

(3) The submission of a written extension request under paragraph (f)(2) of this section does not relieve you of your obligation to comply with the requirements of this part. The Regional Administrator may request a copy of your Plan to evaluate the extension request. When the Regional Administrator authorizes an extension of time for particular equipment or other specific aspects of the Plan, such extension does not affect your obligation to comply with the requirements related to other equipment or other specific aspects of the Plan for which the Regional Administrator has not expressly authorized an extension.

(g) *Qualified Facilities.* The owner or operator of a qualified facility as defined in this subparagraph may self-certify his facility's Plan, as provided in §112.6. A qualified facility is one that meets the following Tier I or Tier II qualified facility criteria:

(1) A Tier I qualified facility meets the qualification criteria in paragraph

(g)(2) of this section and has no individual aboveground oil storage container with a capacity greater than 5,000 U.S. gallons.

(2) A Tier II qualified facility is one that has had no single discharge as described in § 112.1(b) exceeding 1,000 U.S. gallons or no two discharges as described in § 112.1(b) each exceeding 42 U.S. gallons within any twelve month period in the three years prior to the SPCC Plan self-certification date, or since becoming subject to this part if the facility has been in operation for less than three years (other than discharges as described in § 112.1(b) that are the result of natural disasters, acts of war, or terrorism), and has an aggregate aboveground oil storage capacity of 10,000 U.S. gallons or less.

[67 FR 47140, July 17, 2002, as amended at 68 FR 1351, Jan. 9, 2003; 68 FR 18894, Apr. 17, 2003; 69 FR 48798, Aug. 11, 2004; 71 FR 8466, Feb. 17, 2006; 71 FR 77290, Dec. 26, 2006; 72 FR 27447, May 16, 2007; 73 FR 74301, Dec. 5, 2008, 74 FR 29141, June 19, 2009; 74 FR 58809, Nov. 13, 2009; 75 FR 63102, Oct. 14, 2010; 76 FR 21660, Apr. 18, 2011; 76 FR 64248, Oct. 18, 2011; 76 FR 72124, Nov. 22, 2011]

§ 112.4 Amendment of Spill Prevention, Control, and Countermeasure Plan by Regional Administrator.

If you are the owner or operator of a facility subject to this part, you must:

(a) Notwithstanding compliance with § 112.3, whenever your facility has discharged more than 1,000 U.S. gallons of oil in a single discharge as described in § 112.1(b), or discharged more than 42 U.S. gallons of oil in each of two discharges as described in § 112.1(b), occurring within any twelve month period, submit the following information to the Regional Administrator within 60 days from the time the facility becomes subject to this section:

(1) Name of the facility;

(2) Your name;

(3) Location of the facility;

(4) Maximum storage or handling capacity of the facility and normal daily throughput;

(5) Corrective action and countermeasures you have taken, including a description of equipment repairs and replacements;

(6) An adequate description of the facility, including maps, flow diagrams, and topographical maps, as necessary;

(7) The cause of such discharge as described in § 112.1(b), including a failure analysis of the system or subsystem in which the failure occurred;

(8) Additional preventive measures you have taken or contemplated to minimize the possibility of recurrence; and

(9) Such other information as the Regional Administrator may reasonably require pertinent to the Plan or discharge.

(b) Take no action under this section until it applies to your facility. This section does not apply until the expiration of the time permitted for the initial preparation and implementation of the Plan under § 112.3, but not including any amendments to the Plan.

(c) Send to the appropriate agency or agencies in charge of oil pollution control activities in the State in which the facility is located a complete copy of all information you provided to the Regional Administrator under paragraph (a) of this section. Upon receipt of the information such State agency or agencies may conduct a review and make recommendations to the Regional Administrator as to further procedures, methods, equipment, and other requirements necessary to prevent and to contain discharges from your facility.

(d) Amend your Plan, if after review by the Regional Administrator of the information you submit under paragraph (a) of this section, or submission of information to EPA by the State agency under paragraph (c) of this section, or after on-site review of your Plan, the Regional Administrator requires that you do so. The Regional Administrator may require you to amend your Plan if he finds that it does not meet the requirements of this part or that amendment is necessary to prevent and contain discharges from your facility.

(e) Act in accordance with this paragraph when the Regional Administrator proposes by certified mail or by personal delivery that you amend your SPCC Plan. If the owner or operator is a corporation, he must also notify by mail the registered agent of such corporation, if any and if known, in the State in which the facility is located. The Regional Administrator must specify the terms of such proposed

amendment. Within 30 days from receipt of such notice, you may submit written information, views, and arguments on the proposed amendment. After considering all relevant material presented, the Regional Administrator must either notify you of any amendment required or rescind the notice. You must amend your Plan as required within 30 days after such notice, unless the Regional Administrator, for good cause, specifies another effective date. You must implement the amended Plan as soon as possible, but not later than six months after you amend your Plan, unless the Regional Administrator specifies another date.

(f) If you appeal a decision made by the Regional Administrator requiring an amendment to an SPCC Plan, send the appeal to the EPA Administrator in writing within 30 days of receipt of the notice from the Regional Administrator requiring the amendment under paragraph (e) of this section. You must send a complete copy of the appeal to the Regional Administrator at the time you make the appeal. The appeal must contain a clear and concise statement of the issues and points of fact in the case. It may also contain additional information from you, or from any other person. The EPA Administrator may request additional information from you, or from any other person. The EPA Administrator must render a decision within 60 days of receiving the appeal and must notify you of his decision.

§ 112.5 Amendment of Spill Prevention, Control, and Countermeasure Plan by owners or operators.

If you are the owner or operator of a facility subject to this part, you must:

(a) Amend the SPCC Plan for your facility in accordance with the general requirements in § 112.7, and with any specific section of this part applicable to your facility, when there is a change in the facility design, construction, operation, or maintenance that materially affects its potential for a discharge as described in § 112.1(b). Examples of changes that may require amendment of the Plan include, but are not limited to: commissioning or decommissioning containers; replacement, reconstruction, or movement of containers; reconstruction, replacement, or installation of piping systems; construction or demolition that might alter secondary containment structures; changes of product or service; or revision of standard operation or maintenance procedures at a facility. An amendment made under this section must be prepared within six months, and implemented as soon as possible, but not later than six months following preparation of the amendment.

(b) Notwithstanding compliance with paragraph (a) of this section, complete a review and evaluation of the SPCC Plan at least once every five years from the date your facility becomes subject to this part; or, if your facility was in operation on or before August 16, 2002, five years from the date your last review was required under this part. As a result of this review and evaluation, you must amend your SPCC Plan within six months of the review to include more effective prevention and control technology if the technology has been field-proven at the time of the review and will significantly reduce the likelihood of a discharge as described in § 112.1(b) from the facility. You must implement any amendment as soon as possible, but not later than six months following preparation of any amendment. You must document your completion of the review and evaluation, and must sign a statement as to whether you will amend the Plan, either at the beginning or end of the Plan or in a log or an appendix to the Plan. The following words will suffice, ''I have completed review and evaluation of the SPCC Plan for (name of facility) on (date), and will (will not) amend the Plan as a result.''

(c) Except as provided in § 112.6, have a Professional Engineer certify any technical amendments to your Plan in accordance with § 112.3(d).

[67 FR 47140, July 17, 2002, as amended at 71 FR 77291, Dec. 26, 2006; 73 FR 74301, Dec. 5, 2008; 74 FR 58809, Nov. 13, 2009]

§ 112.6 Qualified Facilities Plan Requirements.

Qualified facilities meeting the Tier I applicability criteria in § 112.3(g)(1) are

subject to the requirements in paragraph (a) of this section. Qualified facilities meeting the Tier II applicability criteria in § 112.3(g)(2) are subject to the requirements in paragraph (b) of this section.

(a) *Tier I Qualified Facilities*—(1) *Preparation and Self-Certification of the Plan.* If you are an owner or operator of a facility that meets the Tier I qualified facility criteria in § 112.3(g)(1), you must either: comply with the requirements of paragraph (a)(3) of this section; or prepare and implement a Plan meeting requirements of paragraph (b) of this section; or prepare and implement a Plan meeting the general Plan requirements in § 112.7 and applicable requirements in subparts B and C, including having the Plan certified by a Professional Engineer as required under § 112.3(d). If you do not follow the appendix G template, you must prepare an equivalent Plan that meets all of the applicable requirements listed in this part, and you must supplement it with a section cross-referencing the location of requirements listed in this part and the equivalent requirements in the other prevention plan. To complete the template in appendix G, you must certify that:

(i) You are familiar with the applicable requirements of 40 CFR part 112;

(ii) You have visited and examined the facility;

(iii) You prepared the Plan in accordance with accepted and sound industry practices and standards;

(iv) You have established procedures for required inspections and testing in accordance with industry inspection and testing standards or recommended practices;

(v) You will fully implement the Plan;

(vi) The facility meets the qualification criteria in § 112.3(g)(1);

(vii) The Plan does not deviate from any requirement of this part as allowed by § 112.7(a)(2) and 112.7(d) or include measures pursuant to § 112.9(c)(6) for produced water containers and any associated piping; and

(viii) The Plan and individual(s) responsible for implementing this Plan have the approval of management, and the facility owner or operator has committed the necessary resources to fully implement this Plan.

(2) *Technical Amendments.* You must certify any technical amendments to your Plan in accordance with paragraph (a)(1) of this section when there is a change in the facility design, construction, operation, or maintenance that affects its potential for a discharge as described in § 112.1(b). If the facility change results in the facility no longer meeting the Tier I qualifying criteria in § 112.3(g)(1) because an individual oil storage container capacity exceeds 5,000 U.S. gallons or the facility capacity exceeds 10,000 U.S. gallons in aggregate aboveground storage capacity, within six months following preparation of the amendment, you must either:

(i) Prepare and implement a Plan in accordance with § 112.6(b) if you meet the Tier II qualified facility criteria in § 112.3(g)(2); or

(ii) Prepare and implement a Plan in accordance with the general Plan requirements in § 112.7, and applicable requirements in subparts B and C, including having the Plan certified by a Professional Engineer as required under § 112.3(d).

(3) *Plan Template and Applicable Requirements.* Prepare and implement an SPCC Plan that meets the following requirements under § 112.7 and in subparts B and C of this part: introductory paragraph of §§ 112.7, 112.7(a)(3)(i), 112.7(a)(3)(iv), 112.7(a)(3)(vi), 112.7(a)(4), 112.7(a)(5), 112.7(c), 112.7(e), 112.7(f), 112.7(g), 112.7(k), 112.8(b)(1), 112.8(b)(2), 112.8(c)(1), 112.8(c)(3), 112.8(c)(4), 112.8(c)(5), 112.8(c)(6), 112.8(c)(10), 112.8(d)(4), 112.9(b), 112.9(c)(1), 112.9(c)(2), 112.9(c)(3), 112.9(c)(4), 112.9(c)(5), 112.9(d)(1), 112.9(d)(3), 112.9(d)(4), 112.10(b), 112.10(c), 112.10(d), 112.12(b)(1), 112.12(b)(2), 112.12(c)(1), 112.12(c)(3), 112.12(c)(4), 112.12(c)(5), 112.12(c)(6), 112.12(c)(10), and 112.12(d)(4). The template in appendix G to this part has been developed to meet the requirements of 40 CFR part 112 and, when completed and signed by the owner or operator, may be used as the SPCC Plan. Additionally, you must meet the following requirements:

(i) *Failure analysis, in lieu of the requirements in § 112.7(b).* Where experience indicates a reasonable potential

for equipment failure (such as loading or unloading equipment, tank overflow, rupture, or leakage, or any other equipment known to be a source of discharge), include in your Plan a prediction of the direction and total quantity of oil which could be discharged from the facility as a result of each type of major equipment failure.

(ii) *Bulk storage container secondary containment, in lieu of the requirements in §§ 112.8(c)(2) and (c)(11) and 112.12(c)(2) and (c)(11).* Construct all bulk storage container installations (except mobile refuelers and other non-transportation-related tank trucks), including mobile or portable oil storage containers, so that you provide a secondary means of containment for the entire capacity of the largest single container plus additional capacity to contain precipitation. Dikes, containment curbs, and pits are commonly employed for this purpose. You may also use an alternative system consisting of a drainage trench enclosure that must be arranged so that any discharge will terminate and be safely confined in a catchment basin or holding pond. Position or locate mobile or portable oil storage containers to prevent a discharge as described in § 112.1(b).

(iii) *Overfill prevention, in lieu of the requirements in §§ 112.8(c)(8) and 112.12(c)(8).* Ensure that each container is provided with a system or documented procedure to prevent overfills of the container, describe the system or procedure in the SPCC Plan and regularly test to ensure proper operation or efficacy.

(b) *Tier II Qualified Facilities*—(1) *Preparation and Self-Certification of Plan.* If you are the owner or operator of a facility that meets the Tier II qualified facility criteria in § 112.3(g)(2), you may choose to self-certify your Plan. You must certify in the Plan that:

(i) You are familiar with the requirements of this part;

(ii) You have visited and examined the facility;

(iii) The Plan has been prepared in accordance with accepted and sound industry practices and standards, and with the requirements of this part;

(iv) Procedures for required inspections and testing have been established;

(v) You will fully implement the Plan;

(vi) The facility meets the qualification criteria set forth under § 112.3(g)(2);

(vii) The Plan does not deviate from any requirement of this part as allowed by § 112.7(a)(2) and 112.7(d) or include measures pursuant to § 112.9(c)(6) for produced water containers and any associated piping, except as provided in paragraph (b)(3) of this section; and

(viii) The Plan and individual(s) responsible for implementing the Plan have the full approval of management and the facility owner or operator has committed the necessary resources to fully implement the Plan.

(2) *Technical Amendments.* If you self-certify your Plan pursuant to paragraph (b)(1) of this section, you must certify any technical amendments to your Plan in accordance with paragraph (b)(1) of this section when there is a change in the facility design, construction, operation, or maintenance that affects its potential for a discharge as described in § 112.1(b), except:

(i) If a Professional Engineer certified a portion of your Plan in accordance with paragraph (b)(4) of this section, and the technical amendment affects this portion of the Plan, you must have the amended provisions of your Plan certified by a Professional Engineer in accordance with paragraph (b)(4)(ii) of this section.

(ii) If the change is such that the facility no longer meets the Tier II qualifying criteria in § 112.3(g)(2) because it exceeds 10,000 U.S. gallons in aggregate aboveground storage capacity you must, within six months following the change, prepare and implement a Plan in accordance with the general Plan requirements in § 112.7 and the applicable requirements in subparts B and C of this part, including having the Plan certified by a Professional Engineer as required under § 112.3(d).

(3) *Applicable Requirements.* Except as provided in this paragraph, your self-certified SPCC Plan must comply with § 112.7 and the applicable requirements in subparts B and C of this part:

(i) *Environmental Equivalence*. Your Plan may not include alternate methods which provide environmental equivalence pursuant to § 112.7(a)(2), unless each alternate method has been reviewed and certified in writing by a Professional Engineer, as provided in paragraph (b)(4) of this section.

(ii) *Impracticability*. Your Plan may not include any determinations that secondary containment is impracticable and provisions in lieu of secondary containment pursuant to § 112.7(d), unless each such determination and alternate measure has been reviewed and certified in writing by a Professional Engineer, as provided in paragraph (b)(4) of this section.

(iii) *Produced Water Containers*. Your Plan may not include any alternative procedures for skimming produced water containers in lieu of sized secondary containment pursuant to § 112.9(c)(6), unless they have been reviewed and certified in writing by a Professional Engineer, as provided in paragraph (b)(4) of this section.

(4) *Professional Engineer Certification of Portions of a Qualified Facility's Self-Certified Plan*.

(i) As described in paragraph (b)(3) of this section, the facility owner or operator may not self-certify alternative measures allowed under § 112.7(a)(2) or (d), that are included in the facility's Plan. Such measures must be reviewed and certified, in writing, by a licensed Professional Engineer. For each alternative measure allowed under § 112.7(a)(2), the Plan must be accompanied by a written statement by a Professional Engineer that states the reason for nonconformance and describes the alternative method and how it provides equivalent environmental protection in accordance with § 112.7(a)(2). For each determination of impracticability of secondary containment pursuant to § 112.7(d), the Plan must clearly explain why secondary containment measures are not practicable at this facility and provide the alternative measures required in § 112.7(d) in lieu of secondary containment. By certifying each measure allowed under § 112.7(a)(2) and (d), the Professional Engineer attests:

(A) That he is familiar with the requirements of this part;

(B) That he or his agent has visited and examined the facility; and

(C) That the alternative method of environmental equivalence in accordance with § 112.7(a)(2) or the determination of impracticability and alternative measures in accordance with § 112.7(d) is consistent with good engineering practice, including consideration of applicable industry standards, and with the requirements of this part.

(ii) As described in paragraph (b)(3) of this section, the facility owner or operator may not self-certify measures as described in § 112.9(c)(6) for produced water containers and any associated piping. Such measures must be reviewed and certified, in writing, by a licensed Professional Engineer, in accordance with § 112.3(d)(1)(vi).

(iii) The review and certification by the Professional Engineer under this paragraph is limited to the alternative method which achieves equivalent environmental protection pursuant to § 112.7(a)(2); to the impracticability determination and measures in lieu of secondary containment pursuant to § 112.7(d); or the measures pursuant to § 112.9(c)(6) for produced water containers and any associated piping and appurtenances downstream from the container.

[73 FR 74302, Dec. 5, 2008, as amended at 74 FR 58810, Nov. 13, 2009]

§ 112.7 General requirements for Spill Prevention, Control, and Countermeasure Plans.

If you are the owner or operator of a facility subject to this part you must prepare a Plan in accordance with good engineering practices. The Plan must have the full approval of management at a level of authority to commit the necessary resources to fully implement the Plan. You must prepare the Plan in writing. If you do not follow the sequence specified in this section for the Plan, you must prepare an equivalent Plan acceptable to the Regional Administrator that meets all of the applicable requirements listed in this part, and you must supplement it with a section cross-referencing the location of requirements listed in this part and the equivalent requirements in the other prevention plan. If the Plan calls for additional facilities or procedures,

methods, or equipment not yet fully operational, you must discuss these items in separate paragraphs, and must explain separately the details of installation and operational start-up. As detailed elsewhere in this section, you must also:

(a)(1) Include a discussion of your facility's conformance with the requirements listed in this part.

(2) Comply with all applicable requirements listed in this part. Except as provided in § 112.6, your Plan may deviate from the requirements in paragraphs (g), (h)(2) and (3), and (i) of this section and the requirements in subparts B and C of this part, except the secondary containment requirements in paragraphs (c) and (h)(1) of this section, and §§ 112.8(c)(2), 112.8(c)(11), 112.9(c)(2), 112.9(d)(3), 112.10(c), 112.12(c)(2), and 112.12(c)(11), where applicable to a specific facility, if you provide equivalent environmental protection by some other means of spill prevention, control, or countermeasure. Where your Plan does not conform to the applicable requirements in paragraphs (g), (h)(2) and (3), and (i) of this section, or the requirements of subparts B and C of this part, except the secondary containment requirements in paragraph (c) and (h)(1) of this section, and §§ 112.8(c)(2), 112.8(c)(11), 112.9(c)(2), 112.10(c), 112.12(c)(2), and 112.12(c)(11), you must state the reasons for nonconformance in your Plan and describe in detail alternate methods and how you will achieve equivalent environmental protection. If the Regional Administrator determines that the measures described in your Plan do not provide equivalent environmental protection, he may require that you amend your Plan, following the procedures in § 112.4(d) and (e).

(3) Describe in your Plan the physical layout of the facility and include a facility diagram, which must mark the location and contents of each fixed oil storage container and the storage area where mobile or portable containers are located. The facility diagram must identify the location of and mark as ''exempt'' underground tanks that are otherwise exempted from the requirements of this part under § 112.1(d)(4). The facility diagram must also include all transfer stations and connecting pipes, including intra-facility gathering lines that are otherwise exempted from the requirements of this part under § 112.1(d)(11). You must also address in your Plan:

(i) The type of oil in each fixed container and its storage capacity. For mobile or portable containers, either provide the type of oil and storage capacity for each container or provide an estimate of the potential number of mobile or portable containers, the types of oil, and anticipated storage capacities;

(ii) Discharge prevention measures including procedures for routine handling of products (loading, unloading, and facility transfers, etc.);

(iii) Discharge or drainage controls such as secondary containment around containers and other structures, equipment, and procedures for the control of a discharge;

(iv) Countermeasures for discharge discovery, response, and cleanup (both the facility's capability and those that might be required of a contractor);

(v) Methods of disposal of recovered materials in accordance with applicable legal requirements; and

(vi) Contact list and phone numbers for the facility response coordinator, National Response Center, cleanup contractors with whom you have an agreement for response, and all appropriate Federal, State, and local agencies who must be contacted in case of a discharge as described in § 112.1(b).

(4) Unless you have submitted a response plan under § 112.20, provide information and procedures in your Plan to enable a person reporting a discharge as described in § 112.1(b) to relate information on the exact address or location and phone number of the facility; the date and time of the discharge, the type of material discharged; estimates of the total quantity discharged; estimates of the quantity discharged as described in § 112.1(b); the source of the discharge; a description of all affected media; the cause of the discharge; any damages or injuries caused by the discharge; actions being used to stop, remove, and mitigate the effects of the discharge; whether an evacuation may be needed;

and, the names of individuals and/or organizations who have also been contacted.

(5) Unless you have submitted a response plan under § 112.20, organize portions of the Plan describing procedures you will use when a discharge occurs in a way that will make them readily usable in an emergency, and include appropriate supporting material as appendices.

(b) Where experience indicates a reasonable potential for equipment failure (such as loading or unloading equipment, tank overflow, rupture, or leakage, or any other equipment known to be a source of a discharge), include in your Plan a prediction of the direction, rate of flow, and total quantity of oil which could be discharged from the facility as a result of each type of major equipment failure.

(c) Provide appropriate containment and/or diversionary structures or equipment to prevent a discharge as described in § 112.1(b), except as provided in paragraph (k) of this section for qualified oil-filled operational equipment, and except as provided in § 112.9(d)(3) for flowlines and intra-facility gathering lines at an oil production facility. The entire containment system, including walls and floor, must be capable of containing oil and must be constructed so that any discharge from a primary containment system, such as a tank, will not escape the containment system before cleanup occurs. In determining the method, design, and capacity for secondary containment, you need only to address the typical failure mode, and the most likely quantity of oil that would be discharged. Secondary containment may be either active or passive in design. At a minimum, you must use one of the following prevention systems or its equivalent:

(1) For onshore facilities:

(i) Dikes, berms, or retaining walls sufficiently impervious to contain oil;

(ii) Curbing or drip pans;

(iii) Sumps and collection systems;

(iv) Culverting, gutters, or other drainage systems;

(v) Weirs, booms, or other barriers;

(vi) Spill diversion ponds;

(vii) Retention ponds; or

(viii) Sorbent materials.

(2) For offshore facilities:

(i) Curbing or drip pans; or

(ii) Sumps and collection systems.

(d) Provided your Plan is certified by a licensed Professional Engineer under § 112.3(d), or, in the case of a qualified facility that meets the criteria in § 112.3(g), the relevant sections of your Plan are certified by a licensed Professional Engineer under § 112.6(d), if you determine that the installation of any of the structures or pieces of equipment listed in paragraphs (c) and (h)(1) of this section, and §§ 112.8(c)(2), 112.8(c)(11), 112.9(c)(2), 112.10(c), 112.12(c)(2), and 112.12(c)(11) to prevent a discharge as described in § 112.1(b) from any onshore or offshore facility is not practicable, you must clearly explain in your Plan why such measures are not practicable; for bulk storage containers, conduct both periodic integrity testing of the containers and periodic integrity and leak testing of the valves and piping; and, unless you have submitted a response plan under § 112.20, provide in your Plan the following:

(1) An oil spill contingency plan following the provisions of part 109 of this chapter.

(2) A written commitment of manpower, equipment, and materials required to expeditiously control and remove any quantity of oil discharged that may be harmful.

(e) *Inspections, tests, and records.* Conduct inspections and tests required by this part in accordance with written procedures that you or the certifying engineer develop for the facility. You must keep these written procedures and a record of the inspections and tests, signed by the appropriate supervisor or inspector, with the SPCC Plan for a period of three years. Records of inspections and tests kept under usual and customary business practices will suffice for purposes of this paragraph.

(f) *Personnel, training, and discharge prevention procedures.* (1) At a minimum, train your oil-handling personnel in the operation and maintenance of equipment to prevent discharges; discharge procedure protocols; applicable pollution control laws, rules, and regulations; general facility operations; and, the contents of the facility SPCC Plan.

(2) Designate a person at each applicable facility who is accountable for discharge prevention and who reports to facility management.

(3) Schedule and conduct discharge prevention briefings for your oil-handling personnel at least once a year to assure adequate understanding of the SPCC Plan for that facility. Such briefings must highlight and describe known discharges as described in §112.1(b) or failures, malfunctioning components, and any recently developed precautionary measures.

(g) *Security (excluding oil production facilities).* Describe in your Plan how you secure and control access to the oil handling, processing and storage areas; secure master flow and drain valves; prevent unauthorized access to starter controls on oil pumps; secure out-of-service and loading/unloading connections of oil pipelines; and address the appropriateness of security lighting to both prevent acts of vandalism and assist in the discovery of oil discharges.

(h) *Facility tank car and tank truck loading/unloading rack (excluding offshore facilities).*

(1) Where loading/unloading rack drainage does not flow into a catchment basin or treatment facility designed to handle discharges, use a quick drainage system for tank car or tank truck loading/unloading racks. You must design any containment system to hold at least the maximum capacity of any single compartment of a tank car or tank truck loaded or unloaded at the facility.

(2) Provide an interlocked warning light or physical barrier system, warning signs, wheel chocks or vehicle brake interlock system in the area adjacent to a loading/unloading rack, to prevent vehicles from departing before complete disconnection of flexible or fixed oil transfer lines.

(3) Prior to filling and departure of any tank car or tank truck, closely inspect for discharges the lowermost drain and all outlets of such vehicles, and if necessary, ensure that they are tightened, adjusted, or replaced to prevent liquid discharge while in transit.

(i) If a field-constructed aboveground container undergoes a repair, alteration, reconstruction, or a change in service that might affect the risk of a discharge or failure due to brittle fracture or other catastrophe, or has discharged oil or failed due to brittle fracture failure or other catastrophe, evaluate the container for risk of discharge or failure due to brittle fracture or other catastrophe, and as necessary, take appropriate action.

(j) In addition to the minimal prevention standards listed under this section, include in your Plan a complete discussion of conformance with the applicable requirements and other effective discharge prevention and containment procedures listed in this part or any applicable more stringent State rules, regulations, and guidelines.

(k) *Qualified Oil-filled Operational Equipment.* The owner or operator of a facility with oil-filled operational equipment that meets the qualification criteria in paragraph (k)(1) of this subsection may choose to implement for this qualified oil-filled operational equipment the alternate requirements as described in paragraph (k)(2) of this sub-section in lieu of general secondary containment required in paragraph (c) of this section.

(1) *Qualification Criteria—Reportable Discharge History:* The owner or operator of a facility that has had no single discharge as described in §112.1(b) from any oil-filled operational equipment exceeding 1,000 U.S. gallons or no two discharges as described in §112.1(b) from any oil-filled operational equipment each exceeding 42 U.S. gallons within any twelve month period in the three years prior to the SPCC Plan certification date, or since becoming subject to this part if the facility has been in operation for less than three years (other than oil discharges as described in §112.1(b) that are the result of natural disasters, acts of war or terrorism); and

(2) *Alternative Requirements to General Secondary Containment.* If secondary containment is not provided for qualified oil-filled operational equipment pursuant to paragraph (c) of this section, the owner or operator of a facility with qualified oil-filled operational equipment must:

(i) Establish and document the facility procedures for inspections or a monitoring program to detect equipment failure and/or a discharge; and

(ii) Unless you have submitted a response plan under §112.20, provide in your Plan the following:

(A) An oil spill contingency plan following the provisions of part 109 of this chapter.

(B) A written commitment of manpower, equipment, and materials required to expeditiously control and remove any quantity of oil discharged that may be harmful.

[67 FR 47140, July 17, 2002, as amended at 71 FR 77292, Dec. 26, 2006; 73 FR 74303, Dec. 5, 2008; 74 FR 58810, Nov. 13, 2009]

Subpart B—Requirements for Petroleum Oils and Non-Petroleum Oils, Except Animal Fats and Oils and Greases, and Fish and Marine Mammal Oils; and Vegetable Oils (Including Oils from Seeds, Nuts, Fruits, and Kernels)

SOURCE: 67 FR 47146, July 17, 2002, unless otherwise noted.

§112.8 Spill Prevention, Control, and Countermeasure Plan requirements for onshore facilities (excluding production facilities).

If you are the owner or operator of an onshore facility (excluding a production facility), you must:

(a) Meet the general requirements for the Plan listed under §112.7, and the specific discharge prevention and containment procedures listed in this section.

(b) *Facility drainage.* (1) Restrain drainage from diked storage areas by valves to prevent a discharge into the drainage system or facility effluent treatment system, except where facility systems are designed to control such discharge. You may empty diked areas by pumps or ejectors; however, you must manually activate these pumps or ejectors and must inspect the condition of the accumulation before starting, to ensure no oil will be discharged.

(2) Use valves of manual, open-and-closed design, for the drainage of diked areas. You may not use flapper-type drain valves to drain diked areas. If your facility drainage drains directly into a watercourse and not into an onsite wastewater treatment plant, you must inspect and may drain uncontaminated retained stormwater, as provided in paragraphs (c)(3)(ii), (iii), and (iv) of this section.

(3) Design facility drainage systems from undiked areas with a potential for a discharge (such as where piping is located outside containment walls or where tank truck discharges may occur outside the loading area) to flow into ponds, lagoons, or catchment basins designed to retain oil or return it to the facility. You must not locate catchment basins in areas subject to periodic flooding.

(4) If facility drainage is not engineered as in paragraph (b)(3) of this section, equip the final discharge of all ditches inside the facility with a diversion system that would, in the event of an uncontrolled discharge, retain oil in the facility.

(5) Where drainage waters are treated in more than one treatment unit and such treatment is continuous, and pump transfer is needed, provide two ''lift'' pumps and permanently install at least one of the pumps. Whatever techniques you use, you must engineer facility drainage systems to prevent a discharge as described in §112.1(b) in case there is an equipment failure or human error at the facility.

(c) *Bulk storage containers.* (1) Not use a container for the storage of oil unless its material and construction are compatible with the material stored and conditions of storage such as pressure and temperature.

(2) Construct all bulk storage tank installations (except mobile refuelers and other non-transportation-related tank trucks) so that you provide a secondary means of containment for the entire capacity of the largest single container and sufficient freeboard to contain precipitation. You must ensure that diked areas are sufficiently impervious to contain discharged oil. Dikes, containment curbs, and pits are commonly employed for this purpose. You may also use an alternative system consisting of a drainage trench enclosure that must be arranged so that any discharge will terminate and be safely confined in a facility catchment basin or holding pond.

(3) Not allow drainage of uncontaminated rainwater from the diked area into a storm drain or discharge of an effluent into an open watercourse, lake, or pond, bypassing the facility treatment system unless you:

(i) Normally keep the bypass valve sealed closed.

(ii) Inspect the retained rainwater to ensure that its presence will not cause a discharge as described in § 112.1(b).

(iii) Open the bypass valve and reseal it following drainage under responsible supervision; and

(iv) Keep adequate records of such events, for example, any records required under permits issued in accordance with §§ 122.41(j)(2) and 122.41(m)(3) of this chapter.

(4) Protect any completely buried metallic storage tank installed on or after January 10, 1974 from corrosion by coatings or cathodic protection compatible with local soil conditions. You must regularly leak test such completely buried metallic storage tanks.

(5) Not use partially buried or bunkered metallic tanks for the storage of oil, unless you protect the buried section of the tank from corrosion. You must protect partially buried and bunkered tanks from corrosion by coatings or cathodic protection compatible with local soil conditions.

(6) Test or inspect each aboveground container for integrity on a regular schedule and whenever you make material repairs. You must determine, in accordance with industry standards, the appropriate qualifications for personnel performing tests and inspections, the frequency and type of testing and inspections, which take into account container size, configuration, and design (such as containers that are: shop-built, field-erected, skid-mounted, elevated, equipped with a liner, double-walled, or partially buried). Examples of these integrity tests include, but are not limited to: visual inspection, hydrostatic testing, radiographic testing, ultrasonic testing, acoustic emissions testing, or other systems of non-destructive testing. You must keep comparison records and you must also inspect the container's supports and foundations. In addition, you must frequently inspect the outside of the container for signs of deterioration, discharges, or accumulation of oil inside diked areas. Records of inspections and tests kept under usual and customary business practices satisfy the recordkeeping requirements of this paragraph.

(7) Control leakage through defective internal heating coils by monitoring the steam return and exhaust lines for contamination from internal heating coils that discharge into an open watercourse, or pass the steam return or exhaust lines through a settling tank, skimmer, or other separation or retention system.

(8) Engineer or update each container installation in accordance with good engineering practice to avoid discharges. You must provide at least one of the following devices:

(i) High liquid level alarms with an audible or visual signal at a constantly attended operation or surveillance station. In smaller facilities an audible air vent may suffice.

(ii) High liquid level pump cutoff devices set to stop flow at a predetermined container content level.

(iii) Direct audible or code signal communication between the container gauger and the pumping station.

(iv) A fast response system for determining the liquid level of each bulk storage container such as digital computers, telepulse, or direct vision gauges. If you use this alternative, a person must be present to monitor gauges and the overall filling of bulk storage containers.

(v) You must regularly test liquid level sensing devices to ensure proper operation.

(9) Observe effluent treatment facilities frequently enough to detect possible system upsets that could cause a discharge as described in § 112.1(b).

(10) Promptly correct visible discharges which result in a loss of oil from the container, including but not limited to seams, gaskets, piping, pumps, valves, rivets, and bolts. You must promptly remove any accumulations of oil in diked areas.

(11) Position or locate mobile or portable oil storage containers to prevent a discharge as described in § 112.1(b). Except for mobile refuelers and other non-transportation-related tank

trucks, you must furnish a secondary means of containment, such as a dike or catchment basin, sufficient to contain the capacity of the largest single compartment or container with sufficient freeboard to contain precipitation.

(d) *Facility transfer operations, pumping, and facility process.* (1) Provide buried piping that is installed or replaced on or after August 16, 2002, with a protective wrapping and coating. You must also cathodically protect such buried piping installations or otherwise satisfy the corrosion protection standards for piping in part 280 of this chapter or a State program approved under part 281 of this chapter. If a section of buried line is exposed for any reason, you must carefully inspect it for deterioration. If you find corrosion damage, you must undertake additional examination and corrective action as indicated by the magnitude of the damage.

(2) Cap or blank-flange the terminal connection at the transfer point and mark it as to origin when piping is not in service or is in standby service for an extended time.

(3) Properly design pipe supports to minimize abrasion and corrosion and allow for expansion and contraction.

(4) Regularly inspect all aboveground valves, piping, and appurtenances. During the inspection you must assess the general condition of items, such as flange joints, expansion joints, valve glands and bodies, catch pans, pipeline supports, locking of valves, and metal surfaces. You must also conduct integrity and leak testing of buried piping at the time of installation, modification, construction, relocation, or replacement.

(5) Warn all vehicles entering the facility to be sure that no vehicle will endanger aboveground piping or other oil transfer operations.

[67 FR 47146, July 17, 2002, as amended at 71 FR 77293, Dec. 26, 2006; 73 FR 74304, Dec. 5, 2008]

§ 112.9 Spill Prevention, Control, and Countermeasure Plan Requirements for onshore oil production facilities (excluding drilling and workover facilities).

If you are the owner or operator of an onshore oil production facility (excluding a drilling or workover facility), you must:

(a) Meet the general requirements for the Plan listed under § 112.7, and the specific discharge prevention and containment procedures listed under this section.

(b) *Oil production facility drainage.* (1) At tank batteries and separation and treating areas where there is a reasonable possibility of a discharge as described in § 112.1(b), close and seal at all times drains of dikes or drains of equivalent measures required under § 112.7(c)(1), except when draining uncontaminated rainwater. Prior to drainage, you must inspect the diked area and take action as provided in § 112.8(c)(3)(ii), (iii), and (iv). You must remove accumulated oil on the rainwater and return it to storage or dispose of it in accordance with legally approved methods.

(2) Inspect at regularly scheduled intervals field drainage systems (such as drainage ditches or road ditches), and oil traps, sumps, or skimmers, for an accumulation of oil that may have resulted from any small discharge. You must promptly remove any accumulations of oil.

(c) *Oil production facility bulk storage containers.* (1) Not use a container for the storage of oil unless its material and construction are compatible with the material stored and the conditions of storage.

(2) Except as described in paragraph (c)(5) of this section for flow-through process vessels and paragraph (c)(6) of this section for produced water containers and any associated piping and appurtenances downstream from the container, construct all tank battery, separation, and treating facility installations, so that you provide a secondary means of containment for the entire capacity of the largest single container and sufficient freeboard to contain precipitation. You must safely confine drainage from undiked areas in a catchment basin or holding pond.

(3) Except as described in paragraph (c)(5) of this section for flow-through process vessels and paragraph (c)(6) of this section for produced water containers and any associated piping and appurtenances downstream from the

container, periodically and upon a regular schedule visually inspect each container of oil for deterioration and maintenance needs, including the foundation and support of each container that is on or above the surface of the ground.

(4) Engineer or update new and old tank battery installations in accordance with good engineering practice to prevent discharges. You must provide at least one of the following:

(i) Container capacity adequate to assure that a container will not overfill if a pumper/gauger is delayed in making regularly scheduled rounds.

(ii) Overflow equalizing lines between containers so that a full container can overflow to an adjacent container.

(iii) Vacuum protection adequate to prevent container collapse during a pipeline run or other transfer of oil from the container.

(iv) High level sensors to generate and transmit an alarm signal to the computer where the facility is subject to a computer production control system.

(5) *Flow-through process vessels.* The owner or operator of a facility with flow-through process vessels may choose to implement the alternate requirements as described below in lieu of sized secondary containment required in paragraphs (c)(2) and (c)(3) of this section.

(i) Periodically and on a regular schedule visually inspect and/or test flow-through process vessels and associated components (such as dump valves) for leaks, corrosion, or other conditions that could lead to a discharge as described in § 112.1(b).

(ii) Take corrective action or make repairs to flow-through process vessels and any associated components as indicated by regularly scheduled visual inspections, tests, or evidence of an oil discharge.

(iii) Promptly remove or initiate actions to stabilize and remediate any accumulations of oil discharges associated with flow-through process vessels.

(iv) If your facility discharges more than 1,000 U.S. gallons of oil in a single discharge as described in § 112.1(b), or discharges more than 42 U.S. gallons of oil in each of two discharges as described in § 112.1(b) within any twelve month period, from flow-through process vessels (excluding discharges that are the result of natural disasters, acts of war, or terrorism) then you must, within six months from the time the facility becomes subject to this paragraph, ensure that all flow-through process vessels subject to this subpart comply with § 112.9(c)(2) and (c)(3).

(6) *Produced water containers.* For each produced water container, comply with § 112.9(c)(1) and (c)(4); and § 112.9(c)(2) and (c)(3), or comply with the provisions of the following paragraphs (c)(6)(i) through (v):

(i) Implement, on a regular schedule, a procedure for each produced water container that is designed to separate the free-phase oil that accumulates on the surface of the produced water. Include in the Plan a description of the procedures, frequency, amount of free-phase oil expected to be maintained inside the container, and a Professional Engineer certification in accordance with § 112.3(d)(1)(vi). Maintain records of such events in accordance with § 112.7(e). Records kept under usual and customary business practices will suffice for purposes of this paragraph. If this procedure is not implemented as described in the Plan or no records are maintained, then you must comply with § 112.9(c)(2) and (c)(3).

(ii) On a regular schedule, visually inspect and/or test the produced water container and associated piping for leaks, corrosion, or other conditions that could lead to a discharge as described in § 112.1(b) in accordance with good engineering practice.

(iii) Take corrective action or make repairs to the produced water container and any associated piping as indicated by regularly scheduled visual inspections, tests, or evidence of an oil discharge.

(iv) Promptly remove or initiate actions to stabilize and remediate any accumulations of oil discharges associated with the produced water container.

(v) If your facility discharges more than 1,000 U.S. gallons of oil in a single discharge as described in § 112.1(b), or discharges more than 42 U.S. gallons of oil in each of two discharges as described in § 112.1(b) within any twelve month period from a produced water

container subject to this subpart (excluding discharges that are the result of natural disasters, acts of war, or terrorism) then you must, within six months from the time the facility becomes subject to this paragraph, ensure that all produced water containers subject to this subpart comply with § 112.9(c)(2) and (c)(3).

(d) *Facility transfer operations, oil production facility.* (1) Periodically and upon a regular schedule inspect all aboveground valves and piping associated with transfer operations for the general condition of flange joints, valve glands and bodies, drip pans, pipe supports, pumping well polish rod stuffing boxes, bleeder and gauge valves, and other such items.

(2) Inspect saltwater (oil field brine) disposal facilities often, particularly following a sudden change in atmospheric temperature, to detect possible system upsets capable of causing a discharge.

(3) For flowlines and intra-facility gathering lines that are not provided with secondary containment in accordance with § 112.7(c), unless you have submitted a response plan under § 112.20, provide in your Plan the following:

(i) An oil spill contingency plan following the provisions of part 109 of this chapter.

(ii) A written commitment of manpower, equipment, and materials required to expeditiously control and remove any quantity of oil discharged that might be harmful.

(4) Prepare and implement a written program of flowline/intra-facility gathering line maintenance. The maintenance program must address your procedures to:

(i) Ensure that flowlines and intra-facility gathering lines and associated valves and equipment are compatible with the type of production fluids, their potential corrosivity, volume, and pressure, and other conditions expected in the operational environment.

(ii) Visually inspect and/or test flowlines and intra-facility gathering lines and associated appurtenances on a periodic and regular schedule for leaks, oil discharges, corrosion, or other conditions that could lead to a discharge as described in § 112.1(b). For flowlines and intra-facility gathering lines that are not provided with secondary containment in accordance with § 112.7(c), the frequency and type of testing must allow for the implementation of a contingency plan as described under part 109 of this chapter.

(iii) Take corrective action or make repairs to any flowlines and intra-facility gathering lines and associated appurtenances as indicated by regularly scheduled visual inspections, tests, or evidence of a discharge.

(iv) Promptly remove or initiate actions to stabilize and remediate any accumulations of oil discharges associated with flowlines, intra-facility gathering lines, and associated appurtenances.

[73 FR, 74304, Dec. 5, 2008, as amended at 74 FR 58810, Nov. 13, 2009]

§ 112.10 Spill Prevention, Control, and Countermeasure Plan requirements for onshore oil drilling and workover facilities.

If you are the owner or operator of an onshore oil drilling and workover facility, you must:

(a) Meet the general requirements listed under § 112.7, and also meet the specific discharge prevention and containment procedures listed under this section.

(b) Position or locate mobile drilling or workover equipment so as to prevent a discharge as described in § 112.1(b).

(c) Provide catchment basins or diversion structures to intercept and contain discharges of fuel, crude oil, or oily drilling fluids.

(d) Install a blowout prevention (BOP) assembly and well control system before drilling below any casing string or during workover operations. The BOP assembly and well control system must be capable of controlling any well-head pressure that may be encountered while that BOP assembly and well control system are on the well.

§ 112.11 Spill Prevention, Control, and Countermeasure Plan requirements for offshore oil drilling, production, or workover facilities.

If you are the owner or operator of an offshore oil drilling, production, or workover facility, you must:

(a) Meet the general requirements listed under § 112.7, and also meet the specific discharge prevention and containment procedures listed under this section.

(b) Use oil drainage collection equipment to prevent and control small oil discharges around pumps, glands, valves, flanges, expansion joints, hoses, drain lines, separators, treaters, tanks, and associated equipment. You must control and direct facility drains toward a central collection sump to prevent the facility from having a discharge as described in § 112.1(b). Where drains and sumps are not practicable, you must remove oil contained in collection equipment as often as necessary to prevent overflow.

(c) For facilities employing a sump system, provide adequately sized sump and drains and make available a spare pump to remove liquid from the sump and assure that oil does not escape. You must employ a regularly scheduled preventive maintenance inspection and testing program to assure reliable operation of the liquid removal system and pump start-up device. Redundant automatic sump pumps and control devices may be required on some installations.

(d) At facilities with areas where separators and treaters are equipped with dump valves which predominantly fail in the closed position and where pollution risk is high, specially equip the facility to prevent the discharge of oil. You must prevent the discharge of oil by:

(1) Extending the flare line to a diked area if the separator is near shore;

(2) Equipping the separator with a high liquid level sensor that will automatically shut in wells producing to the separator; or

(3) Installing parallel redundant dump valves.

(e) Equip atmospheric storage or surge containers with high liquid level sensing devices that activate an alarm or control the flow, or otherwise prevent discharges.

(f) Equip pressure containers with high and low pressure sensing devices that activate an alarm or control the flow.

(g) Equip containers with suitable corrosion protection.

(h) Prepare and maintain at the facility a written procedure within the Plan for inspecting and testing pollution prevention equipment and systems.

(i) Conduct testing and inspection of the pollution prevention equipment and systems at the facility on a scheduled periodic basis, commensurate with the complexity, conditions, and circumstances of the facility and any other appropriate regulations. You must use simulated discharges for testing and inspecting human and equipment pollution control and countermeasure systems.

(j) Describe in detailed records surface and subsurface well shut-in valves and devices in use at the facility for each well sufficiently to determine their method of activation or control, such as pressure differential, change in fluid or flow conditions, combination of pressure and flow, manual or remote control mechanisms.

(k) Install a BOP assembly and well control system during workover operations and before drilling below any casing string. The BOP assembly and well control system must be capable of controlling any well-head pressure that may be encountered while the BOP assembly and well control system are on the well.

(l) Equip all manifolds (headers) with check valves on individual flowlines.

(m) Equip the flowline with a high pressure sensing device and shut-in valve at the wellhead if the shut-in well pressure is greater than the working pressure of the flowline and manifold valves up to and including the header valves. Alternatively you may provide a pressure relief system for flowlines.

(n) Protect all piping appurtenant to the facility from corrosion, such as with protective coatings or cathodic protection.

(o) Adequately protect sub-marine piping appurtenant to the facility against environmental stresses and

other activities such as fishing operations.

(p) Maintain sub-marine piping appurtenant to the facility in good operating condition at all times. You must periodically and according to a schedule inspect or test such piping for failures. You must document and keep a record of such inspections or tests at the facility.

Subpart C—Requirements for Animal Fats and Oils and Greases, and Fish and Marine Mammal Oils; and for Vegetable Oils, including Oils from Seeds, Nuts, Fruits, and Kernels

SOURCE: 67 FR 57149, July 17, 2002, unless otherwise noted.

§ 112.12 Spill Prevention, Control, and Countermeasure Plan requirements.

If you are the owner or operator of an onshore facility, you must:

(a) Meet the general requirements for the Plan listed under § 112.7, and the specific discharge prevention and containment procedures listed in this section.

(b) *Facility drainage.* (1) Restrain drainage from diked storage areas by valves to prevent a discharge into the drainage system or facility effluent treatment system, except where facility systems are designed to control such discharge. You may empty diked areas by pumps or ejectors; however, you must manually activate these pumps or ejectors and must inspect the condition of the accumulation before starting, to ensure no oil will be discharged.

(2) Use valves of manual, open-and-closed design, for the drainage of diked areas. You may not use flapper-type drain valves to drain diked areas. If your facility drainage drains directly into a watercourse and not into an on-site wastewater treatment plant, you must inspect and may drain uncontaminated retained stormwater, subject to the requirements of paragraphs (c)(3)(ii), (iii), and (iv) of this section.

(3) Design facility drainage systems from undiked areas with a potential for a discharge (such as where piping is located outside containment walls or where tank truck discharges may occur outside the loading area) to flow into ponds, lagoons, or catchment basins designed to retain oil or return it to the facility. You must not locate catchment basins in areas subject to periodic flooding.

(4) If facility drainage is not engineered as in paragraph (b)(3) of this section, equip the final discharge of all ditches inside the facility with a diversion system that would, in the event of an uncontrolled discharge, retain oil in the facility.

(5) Where drainage waters are treated in more than one treatment unit and such treatment is continuous, and pump transfer is needed, provide two ''lift'' pumps and permanently install at least one of the pumps. Whatever techniques you use, you must engineer facility drainage systems to prevent a discharge as described in § 112.1(b) in case there is an equipment failure or human error at the facility.

(c) *Bulk storage containers.* (1) Not use a container for the storage of oil unless its material and construction are compatible with the material stored and conditions of storage such as pressure and temperature.

(2) Construct all bulk storage tank installations (except mobile refuelers and other non-transportation-related tank trucks) so that you provide a secondary means of containment for the entire capacity of the largest single container and sufficient freeboard to contain precipitation. You must ensure that diked areas are sufficiently impervious to contain discharged oil. Dikes, containment curbs, and pits are commonly employed for this purpose. You may also use an alternative system consisting of a drainage trench enclosure that must be arranged so that any discharge will terminate and be safely confined in a facility catchment basin or holding pond.

(3) Not allow drainage of uncontaminated rainwater from the diked area into a storm drain or discharge of an effluent into an open watercourse, lake, or pond, bypassing the facility treatment system unless you:

(i) Normally keep the bypass valve sealed closed.

(ii) Inspect the retained rainwater to ensure that its presence will not cause a discharge as described in § 112.1(b).

(iii) Open the bypass valve and reseal it following drainage under responsible supervision; and

(iv) Keep adequate records of such events, for example, any records required under permits issued in accordance with §§ 122.41(j)(2) and 122.41(m)(3) of this chapter.

(4) Protect any completely buried metallic storage tank installed on or after January 10, 1974 from corrosion by coatings or cathodic protection compatible with local soil conditions. You must regularly leak test such completely buried metallic storage tanks.

(5) Not use partially buried or bunkered metallic tanks for the storage of oil, unless you protect the buried section of the tank from corrosion. You must protect partially buried and bunkered tanks from corrosion by coatings or cathodic protection compatible with local soil conditions.

(6) *Bulk storage container inspections.*

(i) Except for containers that meet the criteria provided in paragraph (c)(6)(ii) of this section, test or inspect each aboveground container for integrity on a regular schedule and whenever you make material repairs. You must determine, in accordance with industry standards, the appropriate qualifications for personnel performing tests and inspections, the frequency and type of testing and inspections, which take into account container size, configuration, and design (such as containers that are: shop-built, field-erected, skid-mounted, elevated, equipped with a liner, double-walled, or partially buried). Examples of these integrity tests include, but are not limited to: Visual inspection, hydrostatic testing, radiographic testing, ultrasonic testing, acoustic emissions testing, or other systems of non-destructive testing. You must keep comparison records and you must also inspect the container's supports and foundations. In addition, you must frequently inspect the outside of the container for signs of deterioration, discharges, or accumulation of oil inside diked areas. Records of inspections and tests kept under usual and customary business practices satisfy the recordkeeping requirements of this paragraph.

(ii) For bulk storage containers that are subject to 21 CFR part 110, are elevated, constructed of austenitic stainless steel, have no external insulation, and are shop-fabricated, conduct formal visual inspection on a regular schedule. In addition, you must frequently inspect the outside of the container for signs of deterioration, discharges, or accumulation of oil inside diked areas. You must determine and document in the Plan the appropriate qualifications for personnel performing tests and inspections. Records of inspections and tests kept under usual and customary business practices satisfy the recordkeeping requirements of this paragraph (c)(6).

(7) Control leakage through defective internal heating coils by monitoring the steam return and exhaust lines for contamination from internal heating coils that discharge into an open watercourse, or pass the steam return or exhaust lines through a settling tank, skimmer, or other separation or retention system.

(8) Engineer or update each container installation in accordance with good engineering practice to avoid discharges. You must provide at least one of the following devices:

(i) High liquid level alarms with an audible or visual signal at a constantly attended operation or surveillance station. In smaller facilities an audible air vent may suffice.

(ii) High liquid level pump cutoff devices set to stop flow at a predetermined container content level.

(iii) Direct audible or code signal communication between the container gauger and the pumping station.

(iv) A fast response system for determining the liquid level of each bulk storage container such as digital computers, telepulse, or direct vision gauges. If you use this alternative, a person must be present to monitor gauges and the overall filling of bulk storage containers.

(v) You must regularly test liquid level sensing devices to ensure proper operation.

(9) Observe effluent treatment facilities frequently enough to detect possible system upsets that could cause a discharge as described in § 112.1(b).

(10) Promptly correct visible discharges which result in a loss of oil from the container, including but not limited to seams, gaskets, piping, pumps, valves, rivets, and bolts. You must promptly remove any accumulations of oil in diked areas.

(11) Position or locate mobile or portable oil storage containers to prevent a discharge as described in § 112.1(b). Except for mobile refuelers and other non-transportation-related tank trucks, you must furnish a secondary means of containment, such as a dike or catchment basin, sufficient to contain the capacity of the largest single compartment or container with sufficient freeboard to contain precipitation.

(d) *Facility transfer operations, pumping, and facility process.* (1) Provide buried piping that is installed or replaced on or after August 16, 2002, with a protective wrapping and coating. You must also cathodically protect such buried piping installations or otherwise satisfy the corrosion protection standards for piping in part 280 of this chapter or a State program approved under part 281 of this chapter. If a section of buried line is exposed for any reason, you must carefully inspect it for deterioration. If you find corrosion damage, you must undertake additional examination and corrective action as indicated by the magnitude of the damage.

(2) Cap or blank-flange the terminal connection at the transfer point and mark it as to origin when piping is not in service or is in standby service for an extended time.

(3) Properly design pipe supports to minimize abrasion and corrosion and allow for expansion and contraction.

(4) Regularly inspect all aboveground valves, piping, and appurtenances. During the inspection you must assess the general condition of items, such as flange joints, expansion joints, valve glands and bodies, catch pans, pipeline supports, locking of valves, and metal surfaces. You must also conduct integrity and leak testing of buried piping at the time of installation, modification, construction, relocation, or replacement.

(5) Warn all vehicles entering the facility to be sure that no vehicle will endanger aboveground piping or other oil transfer operations.

[67 FR 57149, July 17, 2002, as amended at 71 FR 77293, Dec. 26, 2006; 73 FR 74305, Dec. 5, 2008]

§§ 112.13–112.15 [Reserved]

Subpart D—Response Requirements

§ 112.20 Facility response plans.

(a) The owner or operator of any non-transportation-related onshore facility that, because of its location, could reasonably be expected to cause substantial harm to the environment by discharging oil into or on the navigable waters or adjoining shorelines shall prepare and submit a facility response plan to the Regional Administrator, according to the following provisions:

(1) For the owner or operator of a facility in operation on or before February 18, 1993 who is required to prepare and submit a response plan under 33 U.S.C. 1321(j)(5), the Oil Pollution Act of 1990 (Pub. L. 101–380, 33 U.S.C. 2701 *et seq.*) requires the submission of a response plan that satisfies the requirements of 33 U.S.C. 1321(j)(5) no later than February 18, 1993.

(i) The owner or operator of an existing facility that was in operation on or before February 18, 1993 who submitted a response plan by February 18, 1993 shall revise the response plan to satisfy the requirements of this section and resubmit the response plan or updated portions of the response plan to the Regional Administrator by February 18, 1995.

(ii) The owner or operator of an existing facility in operation on or before February 18, 1993 who failed to submit a response plan by February 18, 1993 shall prepare and submit a response plan that satisfies the requirements of this section to the Regional Administrator before August 30, 1994.

(2) The owner or operator of a facility in operation on or after August 30, 1994 that satisfies the criteria in paragraph (f)(1) of this section or that is notified

by the Regional Administrator pursuant to paragraph (b) of this section shall prepare and submit a facility response plan that satisfies the requirements of this section to the Regional Administrator.

(i) For a facility that commenced operations after February 18, 1993 but prior to August 30, 1994, and is required to prepare and submit a response plan based on the criteria in paragraph (f)(1) of this section, the owner or operator shall submit the response plan or updated portions of the response plan, along with a completed version of the response plan cover sheet contained in appendix F to this part, to the Regional Administrator prior to August 30, 1994.

(ii) For a newly constructed facility that commences operation after August 30, 1994, and is required to prepare and submit a response plan based on the criteria in paragraph (f)(1) of this section, the owner or operator shall submit the response plan, along with a completed version of the response plan cover sheet contained in appendix F to this part, to the Regional Administrator prior to the start of operations (adjustments to the response plan to reflect changes that occur at the facility during the start-up phase of operations must be submitted to the Regional Administrator after an operational trial period of 60 days).

(iii) For a facility required to prepare and submit a response plan after August 30, 1994, as a result of a planned change in design, construction, operation, or maintenance that renders the facility subject to the criteria in paragraph (f)(1) of this section, the owner or operator shall submit the response plan, along with a completed version of the response plan cover sheet contained in appendix F to this part, to the Regional Administrator before the portion of the facility undergoing change commences operations (adjustments to the response plan to reflect changes that occur at the facility during the start-up phase of operations must be submitted to the Regional Administrator after an operational trial period of 60 days).

(iv) For a facility required to prepare and submit a response plan after August 30, 1994, as a result of an unplanned event or change in facility characteristics that renders the facility subject to the criteria in paragraph (f)(1) of this section, the owner or operator shall submit the response plan, along with a completed version of the response plan cover sheet contained in appendix F to this part, to the Regional Administrator within six months of the unplanned event or change.

(3) In the event the owner or operator of a facility that is required to prepare and submit a response plan uses an alternative formula that is comparable to one contained in appendix C to this part to evaluate the criterion in paragraph (f)(1)(ii)(B) or (f)(1)(ii)(C) of this section, the owner or operator shall attach documentation to the response plan cover sheet contained in appendix F to this part that demonstrates the reliability and analytical soundness of the alternative formula.

(4) *Preparation and submission of response plans—Animal fat and vegetable oil facilities.* The owner or operator of any non-transportation-related facility that handles, stores, or transports animal fats and vegetable oils must prepare and submit a facility response plan as follows:

(i) *Facilities with approved plans.* The owner or operator of a facility with a facility response plan that has been approved under paragraph (c) of this section by July 31, 2000 need not prepare or submit a revised plan except as otherwise required by paragraphs (b), (c), or (d) of this section.

(ii) *Facilities with plans that have been submitted to the Regional Administrator.* Except for facilities with approved plans as provided in paragraph (a)(4)(i) of this section, the owner or operator of a facility that has submitted a response plan to the Regional Administrator prior to July 31, 2000 must review the plan to determine if it meets or exceeds the applicable provisions of this part. An owner or operator need not prepare or submit a new plan if the existing plan meets or exceeds the applicable provisions of this part. If the plan does not meet or exceed the applicable provisions of this part, the owner or operator must prepare and submit a new plan by September 28, 2000.

(iii) *Newly regulated facilities.* The owner or operator of a newly constructed facility that commences operation after July 31, 2000 must prepare and submit a plan to the Regional Administrator in accordance with paragraph (a)(2)(ii) of this section. The plan must meet or exceed the applicable provisions of this part. The owner or operator of an existing facility that must prepare and submit a plan after July 31, 2000 as a result of a planned or unplanned change in facility characteristics that causes the facility to become regulated under paragraph (f)(1) of this section, must prepare and submit a plan to the Regional Administrator in accordance with paragraph (a)(2)(iii) or (iv) of this section, as appropriate. The plan must meet or exceed the applicable provisions of this part.

(iv) *Facilities amending existing plans.* The owner or operator of a facility submitting an amended plan in accordance with paragraph (d) of this section after July 31, 2000, including plans that had been previously approved, must also review the plan to determine if it meets or exceeds the applicable provisions of this part. If the plan does not meet or exceed the applicable provisions of this part, the owner or operator must revise and resubmit revised portions of an amended plan to the Regional Administrator in accordance with paragraph (d) of this section, as appropriate. The plan must meet or exceed the applicable provisions of this part.

(b)(1) The Regional Administrator may at any time require the owner or operator of any non-transportation-related onshore facility to prepare and submit a facility response plan under this section after considering the factors in paragraph (f)(2) of this section. If such a determination is made, the Regional Administrator shall notify the facility owner or operator in writing and shall provide a basis for the determination. If the Regional Administrator notifies the owner or operator in writing of the requirement to prepare and submit a response plan under this section, the owner or operator of the facility shall submit the response plan to the Regional Administrator within six months of receipt of such written notification.

(2) The Regional Administrator shall review plans submitted by such facilities to determine whether the facility could, because of its location, reasonably be expected to cause significant and substantial harm to the environment by discharging oil into or on the navigable waters or adjoining shorelines.

(c) The Regional Administrator shall determine whether a facility could, because of its location, reasonably be expected to cause significant and substantial harm to the environment by discharging oil into or on the navigable waters or adjoining shorelines, based on the factors in paragraph (f)(3) of this section. If such a determination is made, the Regional Administrator shall notify the owner or operator of the facility in writing and:

(1) Promptly review the facility response plan;

(2) Require amendments to any response plan that does not meet the requirements of this section;

(3) Approve any response plan that meets the requirements of this section; and

(4) Review each response plan periodically thereafter on a schedule established by the Regional Administrator provided that the period between plan reviews does not exceed five years.

(d)(1) The owner or operator of a facility for which a response plan is required under this part shall revise and resubmit revised portions of the response plan within 60 days of each facility change that materially may affect the response to a worst case discharge, including:

(i) A change in the facility's configuration that materially alters the information included in the response plan;

(ii) A change in the type of oil handled, stored, or transferred that materially alters the required response resources;

(iii) A material change in capabilities of the oil spill removal organization(s) that provide equipment and personnel to respond to discharges of oil described in paragraph (h)(5) of this section;

(iv) A material change in the facility's spill prevention and response equipment or emergency response procedures; and

(v) Any other changes that materially affect the implementation of the response plan.

(2) Except as provided in paragraph (d)(1) of this section, amendments to personnel and telephone number lists included in the response plan and a change in the oil spill removal organization(s) that does not result in a material change in support capabilities do not require approval by the Regional Administrator. Facility owners or operators shall provide a copy of such changes to the Regional Administrator as the revisions occur.

(3) The owner or operator of a facility that submits changes to a response plan as provided in paragraph (d)(1) or (d)(2) of this section shall provide the EPA-issued facility identification number (where one has been assigned) with the changes.

(4) The Regional Administrator shall review for approval changes to a response plan submitted pursuant to paragraph (d)(1) of this section for a facility determined pursuant to paragraph (f)(3) of this section to have the potential to cause significant and substantial harm to the environment.

(e) If the owner or operator of a facility determines pursuant to paragraph (a)(2) of this section that the facility could not, because of its location, reasonably be expected to cause substantial harm to the environment by discharging oil into or on the navigable waters or adjoining shorelines, the owner or operator shall complete and maintain at the facility the certification form contained in appendix C to this part and, in the event an alternative formula that is comparable to one contained in appendix C to this part is used to evaluate the criterion in paragraph (f)(1)(ii)(B) or (f)(1)(ii)(C) of this section, the owner or operator shall attach documentation to the certification form that demonstrates the reliability and analytical soundness of the comparable formula and shall notify the Regional Administrator in writing that an alternative formula was used.

(f)(1) A facility could, because of its location, reasonably be expected to cause substantial harm to the environment by discharging oil into or on the navigable waters or adjoining shorelines pursuant to paragraph (a)(2) of this section, if it meets any of the following criteria applied in accordance with the flowchart contained in attachment C-I to appendix C to this part:

(i) The facility transfers oil over water to or from vessels and has a total oil storage capacity greater than or equal to 42,000 gallons; or

(ii) The facility's total oil storage capacity is greater than or equal to 1 million gallons, and one of the following is true:

(A) The facility does not have secondary containment for each aboveground storage area sufficiently large to contain the capacity of the largest aboveground oil storage tank within each storage area plus sufficient freeboard to allow for precipitation;

(B) The facility is located at a distance (as calculated using the appropriate formula in appendix C to this part or a comparable formula) such that a discharge from the facility could cause injury to fish and wildlife and sensitive environments. For further description of fish and wildlife and sensitive environments, see Appendices I, II, and III of the ''Guidance for Facility and Vessel Response Plans: Fish and Wildlife and Sensitive Environments'' (see appendix E to this part, section 13, for availability) and the applicable Area Contingency Plan prepared pursuant to section 311(j)(4) of the Clean Water Act;

(C) The facility is located at a distance (as calculated using the appropriate formula in appendix C to this part or a comparable formula) such that a discharge from the facility would shut down a public drinking water intake; or

(D) The facility has had a reportable oil discharge in an amount greater than or equal to 10,000 gallons within the last 5 years.

(2)(i) To determine whether a facility could, because of its location, reasonably be expected to cause substantial harm to the environment by discharging oil into or on the navigable waters or adjoining shorelines pursuant to paragraph (b) of this section, the Regional Administrator shall consider the following:

(A) Type of transfer operation;

(B) Oil storage capacity;

(C) Lack of secondary containment;

(D) Proximity to fish and wildlife and sensitive environments and other areas determined by the Regional Administrator to possess ecological value;

(E) Proximity to drinking water intakes;

(F) Spill history; and

(G) Other site-specific characteristics and environmental factors that the Regional Administrator determines to be relevant to protecting the environment from harm by discharges of oil into or on navigable waters or adjoining shorelines.

(ii) Any person, including a member of the public or any representative from a Federal, State, or local agency who believes that a facility subject to this section could, because of its location, reasonably be expected to cause substantial harm to the environment by discharging oil into or on the navigable waters or adjoining shorelines may petition the Regional Administrator to determine whether the facility meets the criteria in paragraph (f)(2)(i) of this section. Such petition shall include a discussion of how the factors in paragraph (f)(2)(i) of this section apply to the facility in question. The RA shall consider such petitions and respond in an appropriate amount of time.

(3) To determine whether a facility could, because of its location, reasonably be expected to cause significant and substantial harm to the environment by discharging oil into or on the navigable waters or adjoining shorelines, the Regional Administrator may consider the factors in paragraph (f)(2) of this section as well as the following:

(i) Frequency of past discharges;

(ii) Proximity to navigable waters;

(iii) Age of oil storage tanks; and

(iv) Other facility-specific and Region-specific information, including local impacts on public health.

(g)(1) All facility response plans shall be consistent with the requirements of the National Oil and Hazardous Substance Pollution Contingency Plan (40 CFR part 300) and applicable Area Contingency Plans prepared pursuant to section 311(j)(4) of the Clean Water Act. The facility response plan should be coordinated with the local emergency response plan developed by the local emergency planning committee under section 303 of Title III of the Superfund Amendments and Reauthorization Act of 1986 (42 U.S.C. 11001 *et seq.*). Upon request, the owner or operator should provide a copy of the facility response plan to the local emergency planning committee or State emergency response commission.

(2) The owner or operator shall review relevant portions of the National Oil and Hazardous Substances Pollution Contingency Plan and applicable Area Contingency Plan annually and, if necessary, revise the facility response plan to ensure consistency with these plans.

(3) The owner or operator shall review and update the facility response plan periodically to reflect changes at the facility.

(h) A response plan shall follow the format of the model facility-specific response plan included in appendix F to this part, unless you have prepared an equivalent response plan acceptable to the Regional Administrator to meet State or other Federal requirements. A response plan that does not follow the specified format in appendix F to this part shall have an emergency response action plan as specified in paragraphs (h)(1) of this section and be supplemented with a cross-reference section to identify the location of the elements listed in paragraphs (h)(2) through (h)(10) of this section. To meet the requirements of this part, a response plan shall address the following elements, as further described in appendix F to this part:

(1) *Emergency response action plan.* The response plan shall include an emergency response action plan in the format specified in paragraphs (h)(1)(i) through (viii) of this section that is maintained in the front of the response plan, or as a separate document accompanying the response plan, and that includes the following information:

(i) The identity and telephone number of a qualified individual having full authority, including contracting authority, to implement removal actions;

(ii) The identity of individuals or organizations to be contacted in the event of a discharge so that immediate communications between the qualified individual identified in paragraph (h)(1)

of this section and the appropriate Federal officials and the persons providing response personnel and equipment can be ensured;

(iii) A description of information to pass to response personnel in the event of a reportable discharge;

(iv) A description of the facility's response equipment and its location;

(v) A description of response personnel capabilities, including the duties of persons at the facility during a response action and their response times and qualifications;

(vi) Plans for evacuation of the facility and a reference to community evacuation plans, as appropriate;

(vii) A description of immediate measures to secure the source of the discharge, and to provide adequate containment and drainage of discharged oil; and

(viii) A diagram of the facility.

(2) *Facility information*. The response plan shall identify and discuss the location and type of the facility, the identity and tenure of the present owner and operator, and the identity of the qualified individual identified in paragraph (h)(1) of this section.

(3) *Information about emergency response*. The response plan shall include:

(i) The identity of private personnel and equipment necessary to remove to the maximum extent practicable a worst case discharge and other discharges of oil described in paragraph (h)(5) of this section, and to mitigate or prevent a substantial threat of a worst case discharge (To identify response resources to meet the facility response plan requirements of this section, owners or operators shall follow appendix E to this part or, where not appropriate, shall clearly demonstrate in the response plan why use of appendix E of this part is not appropriate at the facility and make comparable arrangements for response resources);

(ii) Evidence of contracts or other approved means for ensuring the availability of such personnel and equipment;

(iii) The identity and the telephone number of individuals or organizations to be contacted in the event of a discharge so that immediate communications between the qualified individual identified in paragraph (h)(1) of this section and the appropriate Federal official and the persons providing response personnel and equipment can be ensured;

(iv) A description of information to pass to response personnel in the event of a reportable discharge;

(v) A description of response personnel capabilities, including the duties of persons at the facility during a response action and their response times and qualifications;

(vi) A description of the facility's response equipment, the location of the equipment, and equipment testing;

(vii) Plans for evacuation of the facility and a reference to community evacuation plans, as appropriate;

(viii) A diagram of evacuation routes; and

(ix) A description of the duties of the qualified individual identified in paragraph (h)(1) of this section, that include:

(A) Activate internal alarms and hazard communication systems to notify all facility personnel;

(B) Notify all response personnel, as needed;

(C) Identify the character, exact source, amount, and extent of the release, as well as the other items needed for notification;

(D) Notify and provide necessary information to the appropriate Federal, State, and local authorities with designated response roles, including the National Response Center, State Emergency Response Commission, and Local Emergency Planning Committee;

(E) Assess the interaction of the discharged substance with water and/or other substances stored at the facility and notify response personnel at the scene of that assessment;

(F) Assess the possible hazards to human health and the environment due to the release. This assessment must consider both the direct and indirect effects of the release (i.e., the effects of any toxic, irritating, or asphyxiating gases that may be generated, or the effects of any hazardous surface water runoffs from water or chemical agents used to control fire and heat-induced explosion);

(G) Assess and implement prompt removal actions to contain and remove the substance released;

(H) Coordinate rescue and response actions as previously arranged with all response personnel;

(I) Use authority to immediately access company funding to initiate cleanup activities; and

(J) Direct cleanup activities until properly relieved of this responsibility.

(4) *Hazard evaluation.* The response plan shall discuss the facility's known or reasonably identifiable history of discharges reportable under 40 CFR part 110 for the entire life of the facility and shall identify areas within the facility where discharges could occur and what the potential effects of the discharges would be on the affected environment. To assess the range of areas potentially affected, owners or operators shall, where appropriate, consider the distance calculated in paragraph (f)(1)(ii) of this section to determine whether a facility could, because of its location, reasonably be expected to cause substantial harm to the environment by discharging oil into or on the navigable waters or adjoining shorelines.

(5) *Response planning levels.* The response plan shall include discussion of specific planning scenarios for:

(i) A worst case discharge, as calculated using the appropriate worksheet in appendix D to this part. In cases where the Regional Administrator determines that the worst case discharge volume calculated by the facility is not appropriate, the Regional Administrator may specify the worst case discharge amount to be used for response planning at the facility. For complexes, the worst case planning quantity shall be the larger of the amounts calculated for each component of the facility;

(ii) A discharge of 2,100 gallons or less, provided that this amount is less than the worst case discharge amount. For complexes, this planning quantity shall be the larger of the amounts calculated for each component of the facility; and

(iii) A discharge greater than 2,100 gallons and less than or equal to 36,000 gallons or 10 percent of the capacity of the largest tank at the facility, whichever is less, provided that this amount is less than the worst case discharge amount. For complexes, this planning quantity shall be the larger of the amounts calculated for each component of the facility.

(6) *Discharge detection systems.* The response plan shall describe the procedures and equipment used to detect discharges.

(7) *Plan implementation.* The response plan shall describe:

(i) Response actions to be carried out by facility personnel or contracted personnel under the response plan to ensure the safety of the facility and to mitigate or prevent discharges described in paragraph (h)(5) of this section or the substantial threat of such discharges;

(ii) A description of the equipment to be used for each scenario;

(iii) Plans to dispose of contaminated cleanup materials; and

(iv) Measures to provide adequate containment and drainage of discharged oil.

(8) *Self-inspection, drills/exercises, and response training.* The response plan shall include:

(i) A checklist and record of inspections for tanks, secondary containment, and response equipment;

(ii) A description of the drill/exercise program to be carried out under the response plan as described in § 112.21;

(iii) A description of the training program to be carried out under the response plan as described in § 112.21; and

(iv) Logs of discharge prevention meetings, training sessions, and drills/exercises. These logs may be maintained as an annex to the response plan.

(9) *Diagrams.* The response plan shall include site plan and drainage plan diagrams.

(10) *Security systems.* The response plan shall include a description of facility security systems.

(11) *Response plan cover sheet.* The response plan shall include a completed response plan cover sheet provided in section 2.0 of appendix F to this part.

(i)(1) In the event the owner or operator of a facility does not agree with the Regional Administrator's determination that the facility could, because of its location, reasonably be expected to cause substantial harm or significant and substantial harm to the environment by discharging oil into or

on the navigable waters or adjoining shorelines, or that amendments to the facility response plan are necessary prior to approval, such as changes to the worst case discharge planning volume, the owner or operator may submit a request for reconsideration to the Regional Administrator and provide additional information and data in writing to support the request. The request and accompanying information must be submitted to the Regional Administrator within 60 days of receipt of notice of the Regional Administrator's original decision. The Regional Administrator shall consider the request and render a decision as rapidly as practicable.

(2) In the event the owner or operator of a facility believes a change in the facility's classification status is warranted because of an unplanned event or change in the facility's characteristics (i.e., substantial harm or significant and substantial harm), the owner or operator may submit a request for reconsideration to the Regional Administrator and provide additional information and data in writing to support the request. The Regional Administrator shall consider the request and render a decision as rapidly as practicable.

(3) After a request for reconsideration under paragraph (i)(1) or (i)(2) of this section has been denied by the Regional Administrator, an owner or operator may appeal a determination made by the Regional Administrator. The appeal shall be made to the EPA Administrator and shall be made in writing within 60 days of receipt of the decision from the Regional Administrator that the request for reconsideration was denied. A complete copy of the appeal must be sent to the Regional Administrator at the time the appeal is made. The appeal shall contain a clear and concise statement of the issues and points of fact in the case. It also may contain additional information from the owner or operator, or from any other person. The EPA Administrator may request additional information from the owner or operator, or from any other person. The EPA Administrator shall render a decision as rapidly as practicable and shall notify the owner or operator of the decision.

[59 FR 34098, July 1, 1994, as amended at 65 FR 40798, June 30, 2000; 66 FR 34560, June 29, 2001; 67 FR 47151, July 17, 2002]

§ 112.21 Facility response training and drills/exercises.

(a) The owner or operator of any facility required to prepare a facility response plan under § 112.20 shall develop and implement a facility response training program and a drill/exercise program that satisfy the requirements of this section. The owner or operator shall describe the programs in the response plan as provided in § 112.20(h)(8).

(b) The facility owner or operator shall develop a facility response training program to train those personnel involved in oil spill response activities. It is recommended that the training program be based on the USCG's Training Elements for Oil Spill Response, as applicable to facility operations. An alternative program can also be acceptable subject to approval by the Regional Administrator.

(1) The owner or operator shall be responsible for the proper instruction of facility personnel in the procedures to respond to discharges of oil and in applicable oil spill response laws, rules, and regulations.

(2) Training shall be functional in nature according to job tasks for both supervisory and non-supervisory operational personnel.

(3) Trainers shall develop specific lesson plans on subject areas relevant to facility personnel involved in oil spill response and cleanup.

(c) The facility owner or operator shall develop a program of facility response drills/exercises, including evaluation procedures. A program that follows the National Preparedness for Response Exercise Program (PREP) (see appendix E to this part, section 13, for availability) will be deemed satisfactory for purposes of this section. An alternative program can also be acceptable subject to approval by the Regional Administrator.

[59 FR 34101, July 1, 1994, as amended at 65 FR 40798, June 30, 2000]

APPENDIX A TO PART 112—MEMORANDUM OF UNDERSTANDING BETWEEN THE SECRETARY OF TRANSPORTATION AND THE ADMINISTRATOR OF THE ENVIRONMENTAL PROTECTION AGENCY

SECTION II—DEFINITIONS

The Environmental Protection Agency and the Department of Transportation agree that for the purposes of Executive Order 11548, the term:

(1) *Non-transportation-related onshore and offshore facilities* means:

(A) Fixed onshore and offshore oil well drilling facilities including all equipment and appurtenances related thereto used in drilling operations for exploratory or development wells, but excluding any terminal facility, unit or process integrally associated with the handling or transferring of oil in bulk to or from a vessel.

(B) Mobile onshore and offshore oil well drilling platforms, barges, trucks, or other mobile facilities including all equipment and appurtenances related thereto when such mobile facilities are fixed in position for the purpose of drilling operations for exploratory or development wells, but excluding any terminal facility, unit or process integrally associated with the handling or transferring of oil in bulk to or from a vessel.

(C) Fixed onshore and offshore oil production structures, platforms, derricks, and rigs including all equipment and appurtenances related thereto, as well as completed wells and the wellhead separators, oil separators, and storage facilities used in the production of oil, but excluding any terminal facility, unit or process integrally associated with the handling or transferring of oil in bulk to or from a vessel.

(D) Mobile onshore and offshore oil production facilities including all equipment and appurtenances related thereto as well as completed wells and wellhead equipment, piping from wellheads to oil separators, oil separators, and storage facilities used in the production of oil when such mobile facilities are fixed in position for the purpose of oil production operations, but excluding any terminal facility, unit or process integrally associated with the handling or transferring of oil in bulk to or from a vessel.

(E) Oil refining facilities including all equipment and appurtenances related thereto as well as in-plant processing units, storage units, piping, drainage systems and waste treatment units used in the refining of oil, but excluding any terminal facility, unit or process integrally associated with the handling or transferring of oil in bulk to or from a vessel.

(F) Oil storage facilities including all equipment and appurtenances related thereto as well as fixed bulk plant storage, terminal oil storage facilities, consumer storage, pumps and drainage systems used in the storage of oil, but excluding inline or breakout storage tanks needed for the continuous operation of a pipeline system and any terminal facility, unit or process integrally associated with the handling or transferring of oil in bulk to or from a vessel.

(G) Industrial, commercial, agricultural or public facilities which use and store oil, but excluding any terminal facility, unit or process integrally associated with the handling or transferring of oil in bulk to or from a vessel.

(H) Waste treatment facilities including in-plant pipelines, effluent discharge lines, and storage tanks, but excluding waste treatment facilities located on vessels and terminal storage tanks and appurtenances for the reception of oily ballast water or tank washings from vessels and associated systems used for off-loading vessels.

(I) Loading racks, transfer hoses, loading arms and other equipment which are appurtenant to a nontransportation-related facility or terminal facility and which are used to transfer oil in bulk to or from highway vehicles or railroad cars.

(J) Highway vehicles and railroad cars which are used for the transport of oil exclusively within the confines of a nontransportation-related facility and which are not intended to transport oil in interstate or intrastate commerce.

(K) Pipeline systems which are used for the transport of oil exclusively within the confines of a nontransportation-related facility or terminal facility and which are not intended to transport oil in interstate or intrastate commerce, but excluding pipeline systems used to transfer oil in bulk to or from a vessel.

(2) *Transportation-related onshore and offshore facilities* means:

(A) Onshore and offshore terminal facilities including transfer hoses, loading arms and other equipment and appurtenances used for the purpose of handling or transferring oil in bulk to or from a vessel as well as storage tanks and appurtenances for the reception of oily ballast water or tank washings from vessels, but excluding terminal waste treatment facilities and terminal oil storage facilities.

(B) Transfer hoses, loading arms and other equipment appurtenant to a non-transportation-related facility which is used to transfer oil in bulk to or from a vessel.

(C) Interstate and intrastate onshore and offshore pipeline systems including pumps and appurtenances related thereto as well as in-line or breakout storage tanks needed for the continuous operation of a pipeline system, and pipelines from onshore and offshore oil production facilities, but excluding onshore and offshore piping from wellheads to oil separators and pipelines which are used for the transport of oil exclusively within

the confines of a nontransportation-related facility or terminal facility and which are not intended to transport oil in interstate or intrastate commerce or to transfer oil in bulk to or from a vessel.

(D) Highway vehicles and railroad cars which are used for the transport of oil in interstate or intrastate commerce and the equipment and appurtenances related thereto, and equipment used for the fueling of locomotive units, as well as the rights-of-way on which they operate. Excluded are highway vehicles and railroad cars and motive power used exclusively within the confines of a nontransportation-related facility or terminal facility and which are not intended for use in interstate or intrastate commerce.

APPENDIX B TO PART 112—MEMORANDUM OF UNDERSTANDING AMONG THE SECRETARY OF THE INTERIOR, SECRETARY OF TRANSPORTATION, AND ADMINISTRATOR OF THE ENVIRONMENTAL PROTECTION AGENCY

PURPOSE

This Memorandum of Understanding (MOU) establishes the jurisdictional responsibilities for offshore facilities, including pipelines, pursuant to section 311 (j)(1)(c), (j)(5), and (j)(6)(A) of the Clean Water Act (CWA), as amended by the Oil Pollution Act of 1990 (Public Law 101–380). The Secretary of the Department of the Interior (DOI), Secretary of the Department of Transportation (DOT), and Administrator of the Environmental Protection Agency (EPA) agree to the division of responsibilities set forth below for spill prevention and control, response planning, and equipment inspection activities pursuant to those provisions.

BACKGROUND

Executive Order (E.O.) 12777 (56 FR 54757) delegates to DOI, DOT, and EPA various responsibilities identified in section 311(j) of the CWA. Sections 2(b)(3), 2(d)(3), and 2(e)(3) of E.O. 12777 assigned to DOI spill prevention and control, contingency planning, and equipment inspection activities associated with offshore facilities. Section 311(a)(11) defines the term ''offshore facility'' to include facilities of any kind located in, on, or under navigable waters of the United States. By using this definition, the traditional DOI role of regulating facilities on the Outer Continental Shelf is expanded by E.O. 12777 to include inland lakes, rivers, streams, and any other inland waters.

RESPONSIBILITIES

Pursuant to section 2(i) of E.O. 12777, DOI redelegates, and EPA and DOT agree to assume, the functions vested in DOI by sections 2(b)(3), 2(d)(3), and 2(e)(3) of E.O. 12777 as set forth below. For purposes of this MOU, the term ''coast line'' shall be defined as in the Submerged Lands Act (43 U.S.C. 1301(c)) to mean ''the line of ordinary low water along that portion of the coast which is in direct contact with the open sea and the line marking the seaward limit of inland waters.''

1. To EPA, DOI redelegates responsibility for non-transportation-related offshore facilities located landward of the coast line.

2. To DOT, DOI redelegates responsibility for transportation-related facilities, including pipelines, located landward of the coast line. The DOT retains jurisdiction for deepwater ports and their associated seaward pipelines, as delegated by E.O. 12777.

3. The DOI retains jurisdiction over facilities, including pipelines, located seaward of the coast line, except for deepwater ports and associated seaward pipelines delegated by E.O. 12777 to DOT.

EFFECTIVE DATE

This MOU is effective on the date of the final execution by the indicated signatories.

LIMITATIONS

1. The DOI, DOT, and EPA may agree in writing to exceptions to this MOU on a facility-specific basis. Affected parties will receive notification of the exceptions.

2. Nothing in this MOU is intended to replace, supersede, or modify any existing agreements between or among DOI, DOT, or EPA.

MODIFICATION AND TERMINATION

Any party to this agreement may propose modifications by submitting them in writing to the heads of the other agency/department. No modification may be adopted except with the consent of all parties. All parties shall indicate their consent to or disagreement with any proposed modification within 60 days of receipt. Upon the request of any party, representatives of all parties shall meet for the purpose of considering exceptions or modifications to this agreement. This MOU may be terminated only with the mutual consent of all parties.

Dated: November 8, 1993.

Bruce Babbitt,

Secretary of the Interior.

Dated: December 14, 1993.

Federico Peña,

Secretary of Transportation.

Dated: February 3, 1994.

Carol M. Browner,

Administrator, Environmental Protection Agency.

[59 FR 34102, July 1, 1994]

APPENDIX C TO PART 112—SUBSTANTIAL HARM CRITERIA

1.0 INTRODUCTION

The flowchart provided in Attachment C–I to this appendix shows the decision tree with the criteria to identify whether a facility ''could reasonably be expected to cause substantial harm to the environment by discharging into or on the navigable waters or adjoining shorelines.'' In addition, the Regional Administrator has the discretion to identify facilities that must prepare and submit facility-specific response plans to EPA.

1.1 Definitions

1.1.1 *Great Lakes* means Lakes Superior, Michigan, Huron, Erie, and Ontario, their connecting and tributary waters, the Saint Lawrence River as far as Saint Regis, and adjacent port areas.

1.1.2 Higher Volume Port Areas include

(1) Boston, MA;

(2) New York, NY;

(3) Delaware Bay and River to Philadelphia, PA;

(4) St. Croix, VI;

(5) Pascagoula, MS;

(6) Mississippi River from Southwest Pass, LA to Baton Rouge, LA;

(7) Louisiana Offshore Oil Port (LOOP), LA;

(8) Lake Charles, LA;

(9) Sabine-Neches River, TX;

(10) Galveston Bay and Houston Ship Channel, TX;

(11) Corpus Christi, TX;

(12) Los Angeles/Long Beach Harbor, CA;

(13) San Francisco Bay, San Pablo Bay, Carquinez Strait, and Suisun Bay to Antioch, CA;

(14) Straits of Juan de Fuca from Port Angeles, WA to and including Puget Sound, WA;

(15) Prince William Sound, AK; and

(16) Others as specified by the Regional Administrator for any EPA Region.

1.1.3 *Inland Area* means the area shoreward of the boundary lines defined in 46 CFR part 7, except in the Gulf of Mexico. In the Gulf of Mexico, it means the area shoreward of the lines of demarcation (COLREG lines as defined in 33 CFR 80.740–80.850). The inland area does not include the Great Lakes.

1.1.4 *Rivers and Canals* means a body of water confined within the inland area, including the Intracoastal Waterways and other waterways artificially created for navigating that have project depths of 12 feet or less.

2.0 DESCRIPTION OF SCREENING CRITERIA FOR THE SUBSTANTIAL HARM FLOWCHART

A facility that has the potential to cause substantial harm to the environment in the event of a discharge must prepare and submit a facility-specific response plan to EPA in accordance with appendix F to this part. A description of the screening criteria for the substantial harm flowchart is provided below:

2.1 *Non-Transportation-Related Facilities With a Total Oil Storage Capacity Greater Than or Equal to 42,000 Gallons Where Operations Include Over-Water Transfers of Oil.* A non-transportation-related facility with a total oil storage capacity greater than or equal to 42,000 gallons that transfers oil over water to or from vessels must submit a response plan to EPA. Daily oil transfer operations at these types of facilities occur between barges and vessels and onshore bulk storage tanks over open water. These facilities are located adjacent to navigable water.

2.2 *Lack of Adequate Secondary Containment at Facilities With a Total Oil Storage Capacity Greater Than or Equal to 1 Million Gallons.* Any facility with a total oil storage capacity greater than or equal to 1 million gallons without secondary containment sufficiently large to contain the capacity of the largest aboveground oil storage tank within each area plus sufficient freeboard to allow for precipitation must submit a response plan to EPA. Secondary containment structures that meet the standard of good engineering practice for the purposes of this part include berms, dikes, retaining walls, curbing, culverts, gutters, or other drainage systems.

2.3 *Proximity to Fish and Wildlife and Sensitive Environments at Facilities With a Total Oil Storage Capacity Greater Than or Equal to 1 Million Gallons.* A facility with a total oil storage capacity greater than or equal to 1 million gallons must submit its response plan if it is located at a distance such that a discharge from the facility could cause injury (as defined at 40 CFR 112.2) to fish and wildlife and sensitive environments. For further description of fish and wildlife and sensitive environments, see Appendices I, II, and III to DOC/NOAA's ''Guidance for Facility and Vessel Response Plans: Fish and Wildlife and Sensitive Environments'' (see appendix E to this part, section 13, for availability) and the applicable Area Contingency Plan. Facility owners or operators must determine the distance at which an oil discharge could cause injury to fish and wildlife and sensitive environments using the appropriate formula presented in Attachment C–III to this appendix or a comparable formula.

2.4 *Proximity to Public Drinking Water Intakes at Facilities with a Total Oil Storage Capacity Greater than or Equal to 1 Million Gallons* A facility with a total oil storage capacity greater than or equal to 1 million gallons must submit its response plan if it is located at a distance such that a discharge from the facility would shut down a public drinking water intake, which is analogous to a public water system as described at 40 CFR 143.2(c).

The distance at which an oil discharge from an SPCC-regulated facility would shut down a public drinking water intake shall be calculated using the appropriate formula presented in Attachment C–III to this appendix or a comparable formula.

2.5 *Facilities That Have Experienced Reportable Oil Discharges in an Amount Greater Than or Equal to 10,000 Gallons Within the Past 5 Years and That Have a Total Oil Storage Capacity Greater Than or Equal to 1 Million Gallons.* A facility's oil spill history within the past 5 years shall be considered in the evaluation for substantial harm. Any facility with a total oil storage capacity greater than or equal to 1 million gallons that has experienced a reportable oil discharge in an amount greater than or equal to 10,000 gallons within the past 5 years must submit a response plan to EPA.

3.0 Certification for Facilities That Do Not Pose Substantial Harm

If the facility does not meet the substantial harm criteria listed in Attachment C–I to this appendix, the owner or operator shall complete and maintain at the facility the certification form contained in Attachment C–II to this appendix. In the event an alternative formula that is comparable to the one in this appendix is used to evaluate the substantial harm criteria, the owner or operator shall attach documentation to the certification form that demonstrates the reliability and analytical soundness of the comparable formula and shall notify the Regional Administrator in writing that an alternative formula was used.

4.0 References

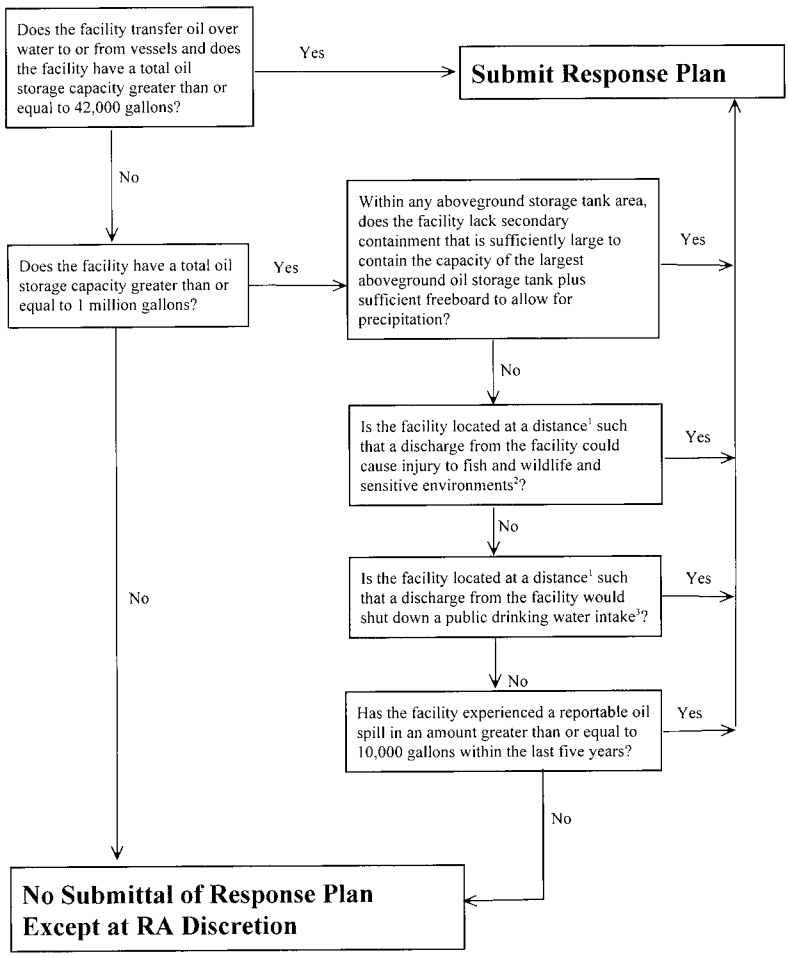
Chow, V.T. 1959. Open Channel Hydraulics. McGraw Hill.

USCG IFR (58 FR 7353, February 5, 1993). This document is available through EPA's rulemaking docket as noted in appendix E to this part, section 13.

ATTACHMENTS TO APPENDIX C

Attachment C-I

Flowchart of Criteria for Substantial Harm



[1] Calculated using the appropriate formula in Attachment C-III to this appendix or a comparable formula.

[2] For further description of fish and wildlife and sensitive environments, see Appendices I,II, and III to DOC/NOAA's "Guidance for Facility and vessel response Plans: Fish and Wildlife and Sensitive Environments" (59 FR 14713, March 29, 1994) and the applicable Area Contingency Plan.

[3] Public drinking water intakes are analogous to public water systems as described at CFR 143.2(c).

ATTACHMENT C-II—CERTIFICATION OF THE APPLICABILITY OF THE SUBSTANTIAL HARM CRITERIA

Facility Name: _____
Facility Address: _____

1. Does the facility transfer oil over water to or from vessels and does the facility have a total oil storage capacity greater than or equal to 42,000 gallons?

Yes _____ No _____

2. Does the facility have a total oil storage capacity greater than or equal to 1 million gallons and does the facility lack secondary containment that is sufficiently large to contain the capacity of the largest aboveground oil storage tank plus sufficient freeboard to allow for precipitation within any aboveground oil storage tank area?

Yes _____ No _____

3. Does the facility have a total oil storage capacity greater than or equal to 1 million gallons and is the facility located at a distance (as calculated using the appropriate formula in Attachment C–III to this appendix or a comparable formula[1]) such that a discharge from the facility could cause injury to fish and wildlife and sensitive environments? For further description of fish and wildlife and sensitive environments, see Appendices I, II, and III to DOC/NOAA's ''Guidance for Facility and Vessel Response Plans: Fish and Wildlife and Sensitive Environments'' (see appendix E to this part, section 13, for availability) and the applicable Area Contingency Plan.

Yes _____ No _____

4. Does the facility have a total oil storage capacity greater than or equal to 1 million gallons and is the facility located at a distance (as calculated using the appropriate formula in Attachment C-III to this appendix or a comparable formula[1]) such that a discharge from the facility would shut down a public drinking water intake[2]?

Yes _____ No _____

5. Does the facility have a total oil storage capacity greater than or equal to 1 million gallons and has the facility experienced a reportable oil discharge in an amount greater than or equal to 10,000 gallons within the last 5 years?

Yes _____ No _____

Certification

I certify under penalty of law that I have personally examined and am familiar with the information submitted in this document, and that based on my inquiry of those individuals responsible for obtaining this information, I believe that the submitted information is true, accurate, and complete.

_____
Signature

_____
Name (please type or print)

_____
Title

_____
Date

[1] If a comparable formula is used, documentation of the reliability and analytical soundness of the comparable formula must be attached to this form.

[2] For the purposes of 40 CFR part 112, public drinking water intakes are analogous to public water systems as described at 40 CFR 143.2(c).

ATTACHMENT C-III—CALCULATION OF THE PLANNING DISTANCE

1.0 Introduction

1.1 The facility owner or operator must evaluate whether the facility is located at a distance such that a discharge from the facility could cause injury to fish and wildlife and sensitive environments or disrupt operations at a public drinking water intake. To quantify that distance, EPA considered oil transport mechanisms over land and on still, tidal influence, and moving navigable waters. EPA has determined that the primary concern for calculation of a planning distance is the transport of oil in navigable waters during adverse weather conditions. Therefore, two formulas have been developed to determine distances for planning purposes from the point of discharge at the facility to the potential site of impact on moving and still waters, respectively. The formula for oil transport on moving navigable water is based on the velocity of the water body and the time interval for arrival of response resources. The still water formula accounts for the spread of discharged oil over the surface of the water. The method to determine oil transport on tidal influence areas is based on the type of oil discharged and the distance down current during ebb tide and up current during flood tide to the point of maximum tidal influence.

1.2 EPA's formulas were designed to be simple to use. However, facility owners or operators may calculate planning distances using more sophisticated formulas, which take into account broader scientific or engineering principles, or local conditions. Such comparable formulas may result in different planning distances than EPA's formulas. In the event that an alternative formula that is comparable to one contained in this appendix is used to evaluate the criterion in 40 CFR 112.20(f)(1)(ii)(B) or (f)(1)(ii)(C), the owner or operator shall attach documentation to the response plan cover sheet contained in appendix F to this part that demonstrates the reliability and analytical soundness of the alternative formula and shall notify the Regional Administrator in

writing that an alternative formula was used.[1]

1.3 A regulated facility may meet the criteria for the potential to cause substantial harm to the environment without having to perform a planning distance calculation. For facilities that meet the substantial harm criteria because of inadequate secondary containment or oil spill history, as listed in the flowchart in Attachment C–I to this appendix, calculation of the planning distance is unnecessary. For facilities that do not meet the substantial harm criteria for secondary containment or oil spill history as listed in the flowchart, calculation of a planning distance for proximity to fish and wildlife and sensitive environments and public drinking water intakes is required, unless it is clear without performing the calculation (e.g., the facility is located in a wetland) that these areas would be impacted.

1.4 A facility owner or operator who must perform a planning distance calculation on navigable water is only required to do so for the type of navigable water conditions (i.e., moving water, still water, or tidal- influenced water) applicable to the facility. If a facility owner or operator determines that more than one type of navigable water condition applies, then the facility owner or operator is required to perform a planning distance calculation for each navigable water type to determine the greatest single distance that oil may be transported. As a result, the final planning distance for oil transport on water shall be the greatest individual distance rather than a summation of each calculated planning distance.

1.5 The planning distance formula for transport on moving waterways contains three variables: the velocity of the navigable water (v), the response time interval (t), and a conversion factor (c). The velocity, v, is determined by using the Chezy-Manning equation, which, in this case, models the flood flow rate of water in open channels. The Chezy-Manning equation contains three variables which must be determined by facility owners or operators. Manning's Roughness Coefficient (for flood flow rates), n, can be determined from Table 1 of this attachment. The hydraulic radius, r, can be estimated using the average mid-channel depth from charts provided by the sources listed in Table 2 of this attachment. The average slope of the river, s, can be determined using topographic maps that can be ordered from the U.S. Geological Survey, as listed in Table 2 of this attachment.

1.6 Table 3 of this attachment contains specified time intervals for estimating the arrival of response resources at the scene of a discharge. Assuming no prior planning, response resources should be able to arrive at the discharge site within 12 hours of the discovery of any oil discharge in Higher Volume Port Areas and within 24 hours in Great Lakes and all other river, canal, inland, and nearshore areas. The specified time intervals in Table 3 of appendix C are to be used only to aid in the identification of whether a facility could cause substantial harm to the environment. Once it is determined that a plan must be developed for the facility, the owner or operator shall reference appendix E to this part to determine appropriate resource levels and response times. The specified time intervals of this appendix include a 3-hour time period for deployment of boom and other response equipment. The Regional Administrator may identify additional areas as appropriate.

2.0 Oil Transport on Moving Navigable Waters

2.1 The facility owner or operator must use the following formula or a comparable formula as described in §112.20(a)(3) to calculate the planning distance for oil transport on moving navigable water:

$d=v\times t\times c$; where

d: the distance downstream from a facility within which fish and wildlife and sensitive environments could be injured or a public drinking water intake would be shut down in the event of an oil discharge (in miles);

v: the velocity of the river/navigable water of concern (in ft/sec) as determined by Chezy-Manning's equation (see below and Tables 1 and 2 of this attachment);

t: the time interval specified in Table 3 based upon the type of water body and location (in hours); and

c: constant conversion factor 0.68 secω mile/hrω ft (3600 sec/hr ÷ 5280 ft/mile).

2.2 Chezy-Manning's equation is used to determine velocity:

$v=1.5/n\times r^{2/3}\times s^{1/2}$; where

v=the velocity of the river of concern (in ft/sec);

n=Manning's Roughness Coefficient from Table 1 of this attachment;

r=the hydraulic radius; the hydraulic radius can be approximated for parabolic channels by multiplying the average mid-

[1] For persistent oils or non-persistent oils, a worst case trajectory model (i.e., an alternative formula) may be substituted for the distance formulas described in still, moving, and tidal waters, subject to Regional Administrator's review of the model. An example of an alternative formula that is comparable to the one contained in this appendix would be a worst case trajectory calculation based on credible adverse winds, currents, and/or river stages, over a range of seasons, weather conditions, and river stages. Based on historical information or a spill trajectory model, the Agency may require that additional fish and wildlife and sensitive environments or public drinking water intakes also be protected.

channel depth of the river (in feet) by 0.667 (sources for obtaining the mid-channel depth are listed in Table 2 of this attachment); and

s=the average slope of the river (unitless) obtained from U.S. Geological Survey topographic maps at the address listed in Table 2 of this attachment.

TABLE 1—MANNING'S ROUGHNESS COEFFICIENT FOR NATURAL STREAMS

[NOTE: Coefficients are presented for high flow rates at or near flood stage.]

Stream description	Roughness coefficient (n)
Minor Streams (Top Width <100 ft.)	
Clean:	
Straight	0.03
Winding	0.04
Sluggish (Weedy, deep pools):	
No trees or brush	0.06
Trees and/or brush	0.10
Major Streams (Top Width >100 ft.)	
Regular section:	
(No boulders/brush)	0.035
Irregular section:	
(Brush)	0.05

TABLE 2—SOURCES OF R AND S FOR THE CHEZY-MANNING EQUATION

All of the charts and related publications for navigational waters may be ordered from:
Distribution Branch
(N/CG33)
National Ocean Service
Riverdale, Maryland 20737–1199
Phone: (301) 436–6990
There will be a charge for materials ordered and a VISA or Mastercard will be accepted.
The mid-channel depth to be used in the calculation of the hydraulic radius (r) can be obtained directly from the following sources:
Charts of Canadian Coastal and Great Lakes Waters:
Canadian Hydrographic Service
Department of Fisheries and Oceans Institute
P.O. Box 8080
1675 Russell Road
Ottawa, Ontario KIG 3H6
Canada
Phone: (613) 998–4931
Charts and Maps of Lower Mississippi River (Gulf of Mexico to Ohio River and St. Francis, White, Big Sunflower, Atchafalaya, and other rivers):
U.S. Army Corps of Engineers
Vicksburg District
P.O. Box 60
Vicksburg, Mississippi 39180
Phone: (601) 634–5000
Charts of Upper Mississippi River and Illinois Waterway to Lake Michigan:
U.S. Army Corps of Engineers
Rock Island District
P.O. Box 2004
Rock Island, Illinois 61204
Phone: (309) 794–5552
Charts of Missouri River:
U.S. Army Corps of Engineers
Omaha District
6014 U.S. Post Office and Courthouse
Omaha, Nebraska 68102
Phone: (402) 221–3900
Charts of Ohio River:
U.S. Army Corps of Engineers
Ohio River Division
P.O. Box 1159
Cincinnati, Ohio 45201
Phone: (513) 684–3002
Charts of Tennessee Valley Authority Reservoirs, Tennessee River and Tributaries:
Tennessee Valley Authority
Maps and Engineering Section
416 Union Avenue
Knoxville, Tennessee 37902
Phone: (615) 632–2921
Charts of Black Warrior River, Alabama River, Tombigbee River, Apalachicola River and Pearl River:
U.S. Army Corps of Engineers
Mobile District
P.O. Box 2288
Mobile, Alabama 36628–0001
Phone: (205) 690–2511
The average slope of the river (s) may be obtained from topographic maps:
U.S. Geological Survey
Map Distribution
Federal Center
Bldg. 41
Box 25286
Denver, Colorado 80225
Additional information can be obtained from the following sources:

1. The State's Department of Natural Resources (DNR) or the State's Aids to Navigation office;
2. A knowledgeable local marina operator; or
3. A knowledgeable local water authority (e.g., State water commission)

2.3 The average slope of the river (s) can be determined from the topographic maps using the following steps:

(1) Locate the facility on the map.

(2) Find the Normal Pool Elevation at the point of discharge from the facility into the water (A).

(3) Find the Normal Pool Elevation of the public drinking water intake or fish and wildlife and sensitive environment located downstream (B) (Note: The owner or operator should use a minimum of 20 miles downstream as a cutoff to obtain the average slope if the location of a specific public drinking water intake or fish and wildlife and sensitive environment is unknown).

(4) If the Normal Pool Elevation is not available, the elevation contours can be used to find the slope. Determine elevation of the water at the point of discharge from the facility (A). Determine the elevation of the

water at the appropriate distance downstream (B). The formula presented below can be used to calculate the slope.

(5) Determine the distance (in miles) between the facility and the public drinking water intake or fish and wildlife and sensitive environments (C).

(6) Use the following formula to find the slope, which will be a unitless value: Average Slope=[(A−B) (ft)/C (miles)] × [1 mile/5280 feet]

2.4 If it is not feasible to determine the slope and mid-channel depth by the Chezy-Manning equation, then the river velocity can be approximated on- site. A specific length, such as 100 feet, can be marked off along the shoreline. A float can be dropped into the stream above the mark, and the time required for the float to travel the distance can be used to determine the velocity in feet per second. However, this method will not yield an average velocity for the length of the stream, but a velocity only for the specific location of measurement. In addition, the flow rate will vary depending on weather conditions such as wind and rainfall. It is recommended that facility owners or operators repeat the measurement under a variety of conditions to obtain the most accurate estimate of the surface water velocity under adverse weather conditions.

2.5 The planning distance calculations for moving and still navigable waters are based on worst case discharges of persistent oils. Persistent oils are of concern because they can remain in the water for significant periods of time and can potentially exist in large quantities downstream. Owners or operators of facilities that store persistent as well as non-persistent oils may use a comparable formula. The volume of oil discharged is not included as part of the planning distance calculation for moving navigable waters. Facilities that will meet this substantial harm criterion are those with facility capacities greater than or equal to 1 million gallons. It is assumed that these facilities are capable of having an oil discharge of sufficient quantity to cause injury to fish and wildlife and sensitive environments or shut down a public drinking water intake. While owners or operators of transfer facilities that store greater than or equal to 42,000 gallons are not required to use a planning distance formula for purposes of the substantial harm criteria, they should use a planning distance calculation in the development of facility-specific response plans.

TABLE 3—SPECIFIED TIME INTERVALS

Operating areas	Substantial harm planning time (hrs)
Higher volume port area.	12 hour arrival+3 hour deployment=15 hours.
Great Lakes ...	24 hour arrival+3 hour deployment=27 hours.
All other rivers and canals, inland, and nearshore areas.	24 hour arrival+3 hour deployment=27 hours.

2.6 *Example of the Planning Distance Calculation for Oil Transport on Moving Navigable Waters.* The following example provides a sample calculation using the planning distance formula for a facility discharging oil into the Monongahela River:

(1) Solve for v by evaluating n, r, and s for the Chezy-Manning equation:

Find the roughness coefficient, n, on Table 1 of this attachment for a regular section of a major stream with a top width greater than 100 feet. The top width of the river can be found from the topographic map.

n=0.035.

Find slope, s, where A=727 feet, B=710 feet, and C=25 miles.

Solving:

$s=[(727\ ft-1710\ ft)/25\ miles]\times[1\ mile/5280\ feet]=1.3\times10^{-4}$

The average mid-channel depth is found by averaging the mid-channel depth for each mile along the length of the river between the facility and the public drinking water intake or the fish or wildlife or sensitive environment (or 20 miles downstream if applicable). This value is multiplied by 0.667 to obtain the hydraulic radius. The mid-channel depth is found by obtaining values for r and s from the sources shown in Table 2 for the Monongahela River.

Solving:

$r=0.667\times20\ feet=13.33\ feet$

Solve for v using:

$v=1.5/n\times r^{2/3}\times s^{1/2}$:

$v=[1.5/0.035]\times(13.33)^{2/3}\times(1.3\times10^{-4})^{1/2}$

$v=2.73$ feet/second

(2) Find t from Table 3 of this attachment. The Monongahela River's resource response time is 27 hours.

(3) Solve for planning distance, d:

$d=v\times t\times c$

$d=(2.73\ ft/sec)\times(27\ hours)\times(0.68\ sec\omega\ mile/hr\omega\ ft)$

$d=50$ miles

Therefore, 50 miles downstream is the appropriate planning distance for this facility.

3.0 Oil Transport on Still Water

3.1 For bodies of water including lakes or ponds that do not have a measurable velocity, the spreading of the oil over the surface must be considered. Owners or operators of facilities located next to still water bodies may use a comparable means of calculating

the planning distance. If a comparable formula is used, documentation of the reliability and analytical soundness of the comparable calculation must be attached to the response plan cover sheet.

3.2 *Example of the Planning Distance Calculation for Oil Transport on Still Water*. To assist those facilities which could potentially discharge into a still body of water, the following analysis was performed to provide an example of the type of formula that may be used to calculate the planning distance. For this example, a worst case discharge of 2,000,000 gallons is used.

(1) The surface area in square feet covered by an oil discharge on still water, A1, can be determined by the following formula,[2] where V is the volume of the discharge in gallons and C is a constant conversion factor:

$A_1=10^5\times V^{3/4}\times C$

$C=0.1643$

$A_1=10^5\times(2{,}000{,}000 \text{ gallons})^{3/4}\times(0.1643)$

$A_1=8.74\times10^8 \text{ ft}^2$

(2) The spreading formula is based on the theoretical condition that the oil will spread uniformly in all directions forming a circle. In reality, the outfall of the discharge will direct the oil to the surface of the water where it intersects the shoreline. Although the oil will not spread uniformly in all directions, it is assumed that the discharge will spread from the shoreline into a semi-circle (this assumption does not account for winds or wave action).

(3) The area of a circle=† r^2

(4) To account for the assumption that oil will spread in a semi-circular shape, the area of a circle is divided by 2 and is designated as A_2.

$A_2=(\dagger\ r^2)/2$

Solving for the radius, r, using the relationship $A_1=A_2$: $8.74\times10^8 \text{ ft}^2=(\dagger^2)/2$

Therefore, r=23,586 ft

r=23,586 ft÷5,280 ft/mile=4.5 miles

Assuming a 20 knot wind under storm conditions:

1 knot=1.15 miles/hour

20 knots×1.15 miles/hour/knot=23 miles/hr

Assuming that the oil slick moves at 3 percent of the wind's speed:[3]

23 miles/hour×0.03=0.69 miles/hour

(5) To estimate the distance that the oil will travel, use the times required for response resources to arrive at different geographic locations as shown in Table 3 of this attachment.

For example:

For Higher Volume Port Areas: 15 hrs×0.69 miles/hr=10.4 miles

For Great Lakes and all other areas: 27 hrs×0.69 miles/hr=18.6 miles

(6) The total distance that the oil will travel from the point of discharge, including the distance due to spreading, is calculated as follows:

Higher Volume Port Areas: d=10.4+4.5 miles or approximately 15 miles

Great Lakes and all other areas: d=18.6+4.5 miles or approximately 23 miles

4.0 Oil Transport on Tidal-Influence Areas

4.1 The planning distance method for tidal influence navigable water is based on worst case discharges of persistent and non-persistent oils. Persistent oils are of primary concern because they can potentially cause harm over a greater distance. For persistent oils discharged into tidal waters, the planning distance is 15 miles from the facility down current during ebb tide and to the point of maximum tidal influence or 15 miles, whichever is less, during flood tide.

4.2 For non-persistent oils discharged into tidal waters, the planning distance is 5 miles from the facility down current during ebb tide and to the point of maximum tidal influence or 5 miles, whichever is less, during flood tide.

4.3 *Example of Determining the Planning Distance for Two Types of Navigable Water Conditions*. Below is an example of how to determine the proper planning distance when a facility could impact two types of navigable water conditions: moving water and tidal water.

(1) Facility X stores persistent oil and is located downstream from locks along a slow moving river which is affected by tides. The river velocity, v, is determined to be 0.5 feet/second from the Chezy-Manning equation used to calculate oil transport on moving navigable waters. The specified time interval, t, obtained from Table 3 of this attachment for river areas is 27 hours. Therefore, solving for the planning distance, d:

d=v×t×c

d=(0.5 ft/sec)×(27 hours)×(0.68 secmile/hrft)

d=9.18 miles.

(2) However, the planning distance for maximum tidal influence down current during ebb tide is 15 miles, which is greater than the calculated 9.18 miles. Therefore, 15 miles downstream is the appropriate planning distance for this facility.

5.0 Oil Transport Over Land

5.1 Facility owners or operators must evaluate the potential for oil to be transported over land to navigable waters of the United States. The owner or operator must evaluate the likelihood that portions of a worst case discharge would reach navigable

[2] Huang, J.C. and Monastero, F.C., 1982. *Review of the State-of-the-Art of Oil Pollution Models*. Final report submitted to the American Petroleum Institute by Raytheon Ocean Systems, Co., East Providence, Rhode Island.

[3] *Oil Spill Prevention & Control*. National Spill Control School, Corpus Christi State University, Thirteenth Edition, May 1990.

waters via open channel flow or from sheet flow across the land, or be prevented from reaching navigable waters when trapped in natural or man-made depressions excluding secondary containment structures.

5.2 As discharged oil travels over land, it may enter a storm drain or open concrete channel intended for drainage. It is assumed that once oil reaches such an inlet, it will flow into the receiving navigable water. During a storm event, it is highly probable that the oil will either flow into the drainage structures or follow the natural contours of the land and flow into the navigable water. Expected minimum and maximum velocities are provided as examples of open concrete channel and pipe flow. The ranges listed below reflect minimum and maximum velocities used as design criteria.[4] The calculation below demonstrates that the time required for oil to travel through a storm drain or open concrete channel to navigable water is negligible and can be considered instantaneous. The velocities are:

For open concrete channels:
maximum velocity=25 feet per second
minimum velocity=3 feet per second
For storm drains:
maximum velocity=25 feet per second
minimum velocity=2 feet per second

5.3 Assuming a length of 0.5 mile from the point of discharge through an open concrete channel or concrete storm drain to a navigable water, the travel times (distance/velocity) are:

1.8 minutes at a velocity of 25 feet per second
14.7 minutes at a velocity of 3 feet per second
22.0 minutes for at a velocity of 2 feet per second

5.4 The distances that shall be considered to determine the planning distance are illustrated in Figure C-I of this attachment. The relevant distances can be described as follows:

D1=Distance from the nearest opportunity for discharge, X_1, to a storm drain or an open concrete channel leading to navigable water.

D2=Distance through the storm drain or open concrete channel to navigable water.

D3=Distance downstream from the outfall within which fish and wildlife and sensitive environments could be injured or a public drinking water intake would be shut down as determined by the planning distance formula.

D4=Distance from the nearest opportunity for discharge, X_2, to fish and wildlife and sensitive environments not bordering navigable water.

5.5 A facility owner or operator whose nearest opportunity for discharge is located within 0.5 mile of a navigable water must complete the planning distance calculation (D3) for the type of navigable water near the facility or use a comparable formula.

5.6 A facility that is located at a distance greater than 0.5 mile from a navigable water must also calculate a planning distance (D3) if it is in close proximity (i.e., D1 is less than 0.5 mile and other factors are conducive to oil travel over land) to storm drains that flow to navigable waters. Factors to be considered in assessing oil transport over land to storm drains shall include the topography of the surrounding area, drainage patterns, man-made barriers (excluding secondary containment structures), and soil distribution and porosity. Storm drains or concrete drainage channels that are located in close proximity to the facility can provide a direct pathway to navigable waters, regardless of the length of the drainage pipe. If D1 is less than or equal to 0.5 mile, a discharge from the facility could pose substantial harm because the time to travel the distance from the storm drain to the navigable water (D2) is virtually instantaneous.

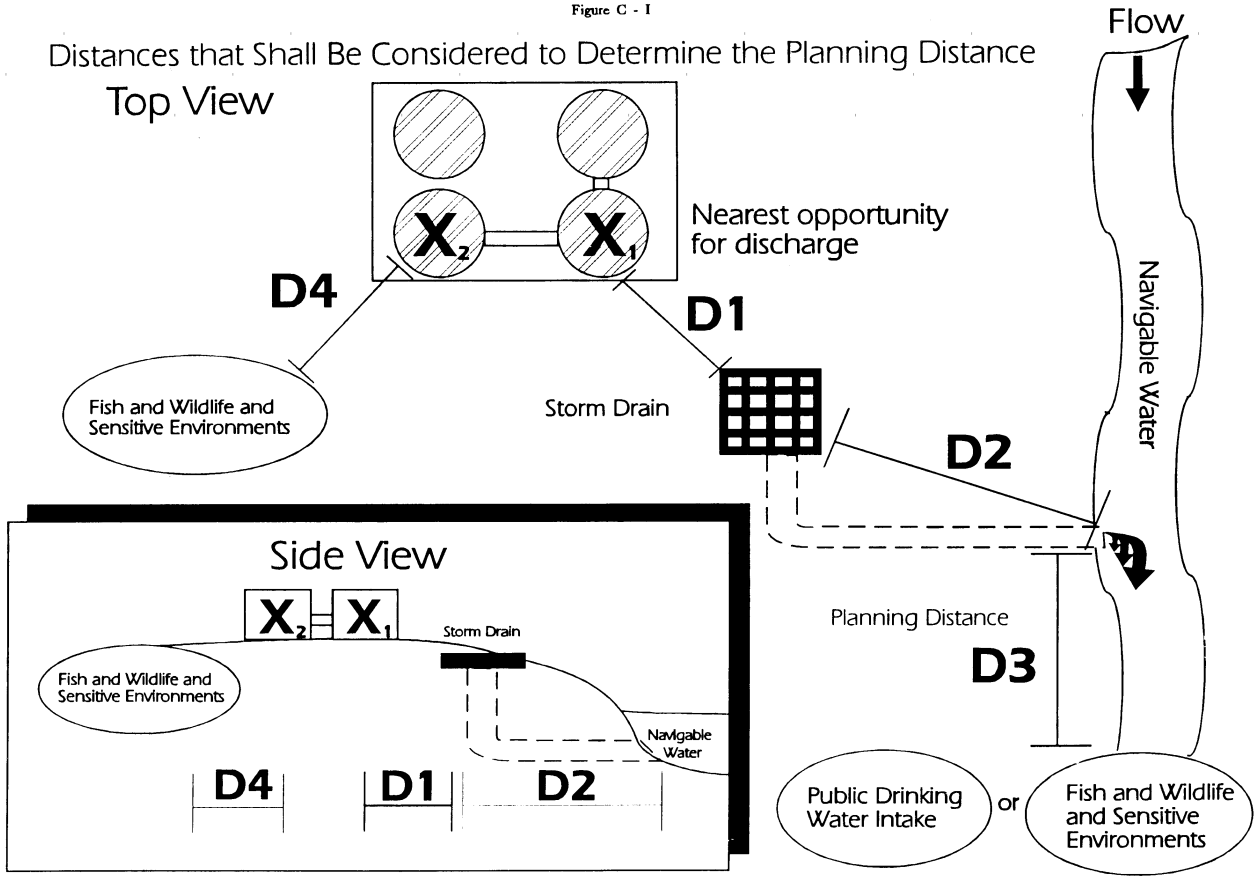
5.7 A facility's proximity to fish and wildlife and sensitive environments not bordering a navigable water, as depicted as D4 in Figure C–I of this attachment, must also be considered, regardless of the distance from the facility to navigable waters. Factors to be considered in assessing oil transport over land to fish and wildlife and sensitive environments should include the topography of the surrounding area, drainage patterns, man-made barriers (excluding secondary containment structures), and soil distribution and porosity.

5.8 If a facility is not found to pose substantial harm to fish and wildlife and sensitive environments not bordering navigable waters via oil transport on land, then supporting documentation should be maintained at the facility. However, such documentation should be submitted with the response plan if a facility is found to pose substantial harm.

[4] The design velocities were obtained from Howard County, Maryland Department of Public Works' Storm Drainage Design Manual.

Figure C - I

Distances that Shall Be Considered to Determine the Planning Distance



** Not to scale **

[59 FR 34102, July 1, 1994, as amended at 65 FR 40798, June 30, 2000; 67 FR 47152, July 17, 2002]

APPENDIX D TO PART 112—DETERMINATION OF A WORST CASE DISCHARGE PLANNING VOLUME

1.0 Instructions

1.1 An owner or operator is required to complete this worksheet if the facility meets the criteria, as presented in appendix C to this part, or it is determined by the RA that the facility could cause substantial harm to the environment. The calculation of a worst case discharge planning volume is used for emergency planning purposes, and is required in 40 CFR 112.20 for facility owners or operators who must prepare a response plan. When planning for the amount of resources and equipment necessary to respond to the worst case discharge planning volume, adverse weather conditions must be taken into consideration. An owner or operator is required to determine the facility's worst case discharge planning volume from either part A of this appendix for an onshore storage facility, or part B of this appendix for an onshore production facility. The worksheet considers the provision of adequate secondary containment at a facility.

1.2 For onshore storage facilities and production facilities, permanently manifolded oil storage tanks are defined as tanks that are designed, installed, and/or operated in such a manner that the multiple tanks function as one storage unit (i.e., multiple tank volumes are equalized). In a worst case discharge scenario, a single failure could cause the discharge of the contents of more than one tank. The owner or operator must provide evidence in the response plan that tanks with common piping or piping systems are not operated as one unit. If such evidence is provided and is acceptable to the RA, the worst case discharge planning volume would be based on the capacity of the largest oil storage tank within a common secondary containment area or the largest oil storage tank within a single secondary containment area, whichever is greater. For permanently manifolded tanks that function as one oil storage unit, the worst case discharge planning volume would be based on the combined oil storage capacity of all manifolded tanks or the capacity of the largest single oil storage tank within a secondary containment area, whichever is greater. For purposes of this rule, permanently manifolded tanks that are separated by internal divisions for each tank are considered to be single tanks and individual manifolded tank volumes are not combined.

1.3 For production facilities, the presence of exploratory wells, production wells, and oil storage tanks must be considered in the calculation. Part B of this appendix takes these additional factors into consideration and provides steps for their inclusion in the total worst case discharge planning volume. Onshore oil production facilities may include all wells, flowlines, separation equipment, storage facilities, gathering lines, and auxiliary non-transportation-related equipment and facilities in a single geographical oil or gas field operated by a single operator. Although a potential worst case discharge planning volume is calculated within each section of the worksheet, the final worst case amount depends on the risk parameter that results in the greatest volume.

1.4 Marine transportation-related transfer facilities that contain fixed aboveground onshore structures used for bulk oil storage are jointly regulated by EPA and the U.S. Coast Guard (USCG), and are termed ''complexes.'' Because the USCG also requires response plans from transportation-related facilities to address a worst case discharge of oil, a separate calculation for the worst case discharge planning volume for USCG-related facilities is included in the USCG IFR (see appendix E to this part, section 13, for availability). All complexes that are jointly regulated by EPA and the USCG must compare both calculations for worst case discharge planning volume derived by using the EPA and USCG methodologies and plan for whichever volume is greater.

PART A: WORST CASE DISCHARGE PLANNING VOLUME CALCULATION FOR ONSHORE STORAGE FACILITIES[1]

Part A of this worksheet is to be completed by the owner or operator of an SPCC-regulated facility (excluding oil production facilities) if the facility meets the criteria as presented in appendix C to this part, or if it is determined by the RA that the facility could cause substantial harm to the environment. If you are the owner or operator of a production facility, please proceed to part B of this worksheet.

A.1 SINGLE-TANK FACILITIES

For facilities containing only one aboveground oil storage tank, the worst case discharge planning volume equals the capacity of the oil storage tank. If adequate secondary containment (sufficiently large to contain the capacity of the aboveground oil storage tank plus sufficient freeboard to allow for precipitation) exists for the oil storage tank, multiply the capacity of the tank by 0.8.

(1) FINAL WORST CASE VOLUME: _____ GAL

(2) Do not proceed further.

[1] ''Storage facilities'' represent all facilities subject to this part, excluding oil production facilities.

A.2 SECONDARY CONTAINMENT—MULTIPLE-TANK FACILITIES

Are *all* aboveground oil storage tanks or groups of aboveground oil storage tanks at the facility *without* adequate secondary containment?[2]

_____ (Y/N)

A.2.1 If the answer is yes, the final worst case discharge planning volume equals the *total aboveground oil storage capacity at the facility*.

(1) FINAL WORST CASE VOLUME: _____ GAL

(2) Do not proceed further.

A.2.2 If the answer is no, calculate the total aboveground oil storage capacity of tanks without adequate secondary containment. If *all* aboveground oil storage tanks or groups of aboveground oil storage tanks at the facility have adequate secondary containment, ENTER ''0'' (zero).

_____ GAL

A.2.3 Calculate the capacity of the largest single aboveground oil storage tank within an adequate secondary containment area or the combined capacity of a group of aboveground oil storage tanks permanently manifolded together, whichever is greater, PLUS THE VOLUME FROM QUESTION A.2.2.

FINAL WORST CASE VOLUME:[3] _____ GAL

PART B: WORST CASE DISCHARGE PLANNING VOLUME CALCULATION FOR ONSHORE PRODUCTION FACILITIES

Part B of this worksheet is to be completed by the owner or operator of an SPCC-regulated oil production facility if the facility meets the criteria presented in appendix C to this part, or if it is determined by the RA that the facility could cause substantial harm. A production facility consists of all wells (producing and exploratory) and related equipment in a single geographical oil or gas field operated by a single operator.

B.1 SINGLE-TANK FACILITIES

B.1.1 For facilities containing only one aboveground oil storage tank, the worst case discharge planning volume equals the capacity of the aboveground oil storage tank plus the production volume of the well with the highest output at the facility. If adequate secondary containment (sufficiently large to contain the capacity of the aboveground oil storage tank plus sufficient freeboard to allow for precipitation) exists for the storage tank, multiply the capacity of the tank by 0.8.

B.1.2 For facilities with production wells producing by pumping, if the rate of the well with the highest output is known and the number of days the facility is unattended can be predicted, then the production volume is equal to the pumping rate of the well multiplied by the greatest number of days the facility is unattended.

B.1.3 If the pumping rate of the well with the highest output is estimated or the maximum number of days the facility is unattended is estimated, then the production volume is determined from the pumping rate of the well multiplied by 1.5 times the greatest number of days that the facility has been or is expected to be unattended.

B.1.4 Attachment D–1 to this appendix provides methods for calculating the production volume for exploratory wells and production wells producing under pressure.

(1) FINAL WORST CASE VOLUME: _____ GAL

(2) Do not proceed further.

B.2 SECONDARY CONTAINMENT—MULTIPLE-TANK FACILITIES

Are *all* aboveground oil storage tanks or groups of aboveground oil storage tanks at the facility *without* adequate secondary containment?

_____ (Y/N)

B.2.1 If the answer is yes, the final worst case volume equals the total aboveground oil storage capacity without adequate secondary containment plus the production volume of the well with the highest output at the facility.

(1) For facilities with production wells producing by pumping, if the rate of the well with the highest output is known and the number of days the facility is unattended can be predicted, then the production volume is equal to the pumping rate of the well multiplied by the greatest number of days the facility is unattended.

(2) If the pumping rate of the well with the highest output is estimated or the maximum number of days the facility is unattended is estimated, then the production volume is determined from the pumping rate of the well multiplied by 1.5 times the greatest number of days that the facility has been or is expected to be unattended.

(3) Attachment D–1 to this appendix provides methods for calculating the production volumes for exploratory wells and production wells producing under pressure.

(A) FINAL WORST CASE VOLUME: _____ GAL

(B) Do not proceed further.

[2] Secondary containment is described in 40 CFR part 112, subparts A through C. Acceptable methods and structures for containment are also given in 40 CFR 112.7(c)(1).

[3] All complexes that are jointly regulated by EPA and the USCG must also calculate the worst case discharge planning volume for the transportation-related portions of the facility and plan for whichever volume is greater.

B.2.2 If the answer is no, calculate the total aboveground oil storage capacity of tanks without adequate secondary containment. If *all* aboveground oil storage tanks or groups of aboveground oil storage tanks at the facility have adequate secondary containment, ENTER ''0'' (zero).

_____ GAL

B.2.3 Calculate the capacity of the largest single aboveground oil storage tank within an adequate secondary containment area or the combined capacity of a group of aboveground oil storage tanks permanently manifolded together, whichever is greater, plus the production volume of the well with the highest output, PLUS THE VOLUME FROM QUESTION B.2.2. Attachment D–1 provides methods for calculating the production volumes for exploratory wells and production wells producing under pressure.

(1) FINAL WORST CASE VOLUME:[4] _____ GAL

(2) Do not proceed further.

ATTACHMENTS TO APPENDIX D

ATTACHMENT D–I—METHODS TO CALCULATE PRODUCTION VOLUMES FOR PRODUCTION FACILITIES WITH EXPLORATORY WELLS OR PRODUCTION WELLS PRODUCING UNDER PRESSURE

1.0 Introduction

The owner or operator of a production facility with exploratory wells or production wells producing under pressure shall compare the well rate of the highest output well (rate of well), in barrels per day, to the ability of response equipment and personnel to recover the volume of oil that could be discharged (rate of recovery), in barrels per day. The result of this comparison will determine the method used to calculate the production volume for the production facility. This production volume is to be used to calculate the worst case discharge planning volume in part B of this appendix.

2.0 Description of Methods

2.1 Method A

If the well rate would overwhelm the response efforts (i.e., rate of well/rate of recovery ≥1), then the production volume would be the 30-day forecasted well rate for a well 10,000 feet deep or less, or the 45-day forecasted well rate for a well deeper than 10,000 feet.

(1) For wells 10,000 feet deep or less:

Production volume=30 days × rate of well.

(2) For wells deeper than 10,000 feet:

Production volume=45 days × rate of well.

2.2 Method B

2.2.1 If the rate of recovery would be greater than the well rate (i.e., rate of well/rate of recovery <1), then the production volume would equal the sum of two terms:

Production volume=discharge $volume_1$ + discharge $volume_2$

2.2.2 The first term represents the volume of the oil discharged from the well between the time of the blowout and the time the response resources are on scene and recovering oil (discharge $volume_1$).

Discharge $volume_1$=(days unattended+days to respond) × (rate of well)

2.2.3 The second term represents the volume of oil discharged from the well after the response resources begin operating until the discharge is stopped, adjusted for the recovery rate of the response resources (discharge $volume_2$).

(1) For wells 10,000 feet deep or less:

Discharge $volume_2$=[30 days − (days unattended + days to respond)] × (rate of well) × (rate of well/rate of recovery)

(2) For wells deeper than 10,000 feet:

Discharge $volume_2$=[45 days − (days unattended + days to respond)] × (rate of well) × (rate of well/rate of recovery)

3.0 Example

3.1 A facility consists of two production wells producing under pressure, which are both less than 10,000 feet deep. The well rate of well A is 5 barrels per day, and the well rate of well B is 10 barrels per day. The facility is unattended for a maximum of 7 days. The facility operator estimates that it will take 2 days to have response equipment and personnel on scene and responding to a blowout, and that the projected rate of recovery will be 20 barrels per day.

(1) First, the facility operator determines that the highest output well is well B. The facility operator calculates the ratio of the rate of well to the rate of recovery:

10 barrels per day/20 barrels per day=0.5 Because the ratio is less than one, the facility operator will use Method B to calculate the production volume.

(2) The first term of the equation is:

Discharge $volume_1$=(7 days + 2 days) × (10 barrels per day)=90 barrels

(3) The second term of the equation is:

Discharge $volume_2$=[30 days—(7 days + 2 days)] × (10 barrels per day) × (0.5)=105 barrels

(4) Therefore, the production volume is:

Production volume=90 barrels + 105 barrels=195 barrels

[4] All complexes that are jointly regulated by EPA and the USCG must also calculate the worst case discharge planning volume for the transportation-related portions of the facility and plan for whichever volume is greater.

3.2 If the recovery rate was 5 barrels per day, the ratio of rate of well to rate of recovery would be 2, so the facility operator would use Method A. The production volume would have been:

30 days × 10 barrels per day=300 barrels

[59 FR 34110, July 1, 1994; 59 FR 49006, Sept. 26, 1994, as amended at 65 FR 40800, June 30, 2000; 67 FR 47152, July 17, 2002]

APPENDIX E TO PART 112—DETERMINATION AND EVALUATION OF REQUIRED RESPONSE RESOURCES FOR FACILITY RESPONSE PLANS

1.0 Purpose and Definitions

1.1 The purpose of this appendix is to describe the procedures to identify response resources to meet the requirements of § 112.20. To identify response resources to meet the facility response plan requirements of 40 CFR 112.20(h), owners or operators shall follow this appendix or, where not appropriate, shall clearly demonstrate in the response plan why use of this appendix is not appropriate at the facility and make comparable arrangements for response resources.

1.2 Definitions.

1.2.1 *Animal fat* means a non-petroleum oil, fat, or grease of animal, fish, or marine mammal origin. Animal fats are further classified based on specific gravity as follows:

(1) Group A—specific gravity less than 0.8.

(2) Group B—specific gravity equal to or greater than 0.8 and less than 1.0.

(3) Group C—specific gravity equal to or greater than 1.0.

1.2.2 *Nearshore* is an operating area defined as extending seaward 12 miles from the boundary lines defined in 46 CFR part 7, except in the Gulf of Mexico. In the Gulf of Mexico, it means the area extending 12 miles from the line of demarcation (COLREG lines) defined in 49 CFR 80.740 and 80.850.

1.2.3 *Non-persistent oils* or *Group 1 oils* include:

(1) A petroleum-based oil that, at the time of shipment, consists of hydrocarbon fractions:

(A) At least 50 percent of which by volume, distill at a temperature of 340 degrees C (645 degrees F); and

(B) At least 95 percent of which by volume, distill at a temperature of 370 degrees C (700 degrees F); and

(2) A non-petroleum oil, other than an animal fat or vegetable oil, with a specific gravity less than 0.8.

1.2.4 *Non-petroleum oil* means oil of any kind that is not petroleum-based, including but not limited to: fats, oils, and greases of animal, fish, or marine mammal origin; and vegetable oils, including oils from seeds, nuts, fruits, and kernels.

1.2.5 *Ocean* means the nearshore area.

1.2.6 *Operating area* means Rivers and Canals, Inland, Nearshore, and Great Lakes geographic location(s) in which a facility is handling, storing, or transporting oil.

1.2.7 *Operating environment* means Rivers and Canals, Inland, Great Lakes, or Ocean. These terms are used to define the conditions in which response equipment is designed to function.

1.2.8 *Persistent oils* include:

(1) A petroleum-based oil that does not meet the distillation criteria for a non-persistent oil. Persistent oils are further classified based on specific gravity as follows:

(A) Group 2—specific gravity less than 0.85;

(B) Group 3—specific gravity equal to or greater than 0.85 and less than 0.95;

(C) Group 4—specific gravity equal to or greater than 0.95 and less than 1.0; or

(D) Group 5—specific gravity equal to or greater than 1.0.

(2) A non-petroleum oil, other than an animal fat or vegetable oil, with a specific gravity of 0.8 or greater. These oils are further classified based on specific gravity as follows:

(A) Group 2—specific gravity equal to or greater than 0.8 and less than 0.85;

(B) Group 3—specific gravity equal to or greater than 0.85 and less than 0.95;

(C) Group 4—specific gravity equal to or greater than 0.95 and less than 1.0; or

(D) Group 5—specific gravity equal to or greater than 1.0.

1.2.9 *Vegetable oil* means a non-petroleum oil or fat of vegetable origin, including but not limited to oils and fats derived from plant seeds, nuts, fruits, and kernels. Vegetable oils are further classified based on specific gravity as follows:

(1) Group A—specific gravity less than 0.8.

(2) Group B—specific gravity equal to or greater than 0.8 and less than 1.0.

(3) Group C—specific gravity equal to or greater than 1.0.

1.2.10 Other definitions are included in § 112.2, section 1.1 of appendix C, and section 3.0 of appendix F.

2.0 Equipment Operability and Readiness

2.1 All equipment identified in a response plan must be designed to operate in the conditions expected in the facility's geographic area (i.e., operating environment). These conditions vary widely based on location and season. Therefore, it is difficult to identify a single stockpile of response equipment that will function effectively in each geographic location (i.e., operating area).

2.2 Facilities handling, storing, or transporting oil in more than one operating environment as indicated in Table 1 of this appendix must identify equipment capable of successfully functioning in each operating environment.

2.3 When identifying equipment for the response plan (based on the use of this appendix), a facility owner or operator must consider the inherent limitations of the operability of equipment components and response systems. The criteria in Table 1 of this appendix shall be used to evaluate the operability in a given environment. These criteria reflect the general conditions in certain operating environments.

2.3.1 The Regional Administrator may require documentation that the boom identified in a facility response plan meets the criteria in Table 1 of this appendix. Absent acceptable documentation, the Regional Administrator may require that the boom be tested to demonstrate that it meets the criteria in Table 1 of this appendix. Testing must be in accordance with ASTM F 715, ASTM F 989, or other tests approved by EPA as deemed appropriate (see appendix E to this part, section 13, for general availability of documents).

2.4 Table 1 of this appendix lists criteria for oil recovery devices and boom. All other equipment necessary to sustain or support response operations in an operating environment must be designed to function in the same conditions. For example, boats that deploy or support skimmers or boom must be capable of being safely operated in the significant wave heights listed for the applicable operating environment.

2.5 A facility owner or operator shall refer to the applicable Area Contingency Plan (ACP), where available, to determine if ice, debris, and weather-related visibility are significant factors to evaluate the operability of equipment. The ACP may also identify the average temperature ranges expected in the facility's operating area. All equipment identified in a response plan must be designed to operate within those conditions or ranges.

2.6 This appendix provides information on response resource mobilization and response times. The distance of the facility from the storage location of the response resources must be used to determine whether the resources can arrive on-scene within the stated time. A facility owner or operator shall include the time for notification, mobilization, and travel of resources identified to meet the medium and Tier 1 worst case discharge requirements identified in sections 4.3 and 9.3 of this appendix (for medium discharges) and section 5.3 of this appendix (for worst case discharges). The facility owner or operator must plan for notification and mobilization of Tier 2 and 3 response resources as necessary to meet the requirements for arrival on-scene in accordance with section 5.3 of this appendix. An on-water speed of 5 knots and a land speed of 35 miles per hour is assumed, unless the facility owner or operator can demonstrate otherwise.

2.7 In identifying equipment, the facility owner or operator shall list the storage location, quantity, and manufacturer's make and model. For oil recovery devices, the effective daily recovery capacity, as determined using section 6 of this appendix, must be included. For boom, the overall boom height (draft and freeboard) shall be included. A facility owner or operator is responsible for ensuring that the identified boom has compatible connectors.

3.0 Determining Response Resources Required for Small Discharges—Petroleum Oils and Non-Petroleum Oils Other Than Animal Fats and Vegetable Oils

3.1 A facility owner or operator shall identify sufficient response resources available, by contract or other approved means as described in §112.2, to respond to a small discharge. A small discharge is defined as any discharge volume less than or equal to 2,100 gallons, but not to exceed the calculated worst case discharge. The equipment must be designed to function in the operating environment at the point of expected use.

3.2 Complexes that are regulated by EPA and the United States Coast Guard (USCG) must also consider planning quantities for the transportation-related transfer portion of the facility.

3.2.1 *Petroleum oils.* The USCG planning level that corresponds to EPA's "small discharge" is termed "the average most probable discharge." A USCG rule found at 33 CFR 154.1020 defines "the average most probable discharge" as the lesser of 50 barrels (2,100 gallons) or 1 percent of the volume of the worst case discharge. Owners or operators of complexes that handle, store, or transport petroleum oils must compare oil discharge volumes for a small discharge and an average most probable discharge, and plan for whichever quantity is greater.

3.2.2 *Non-petroleum oils other than animal fats and vegetable oils.* Owners or operators of complexes that handle, store, or transport non-petroleum oils other than animal fats and vegetable oils must plan for oil discharge volumes for a small discharge. There is no USCG planning level that directly corresponds to EPA's "small discharge." However, the USCG (at 33 CFR 154.545) has requirements to identify equipment to contain oil resulting from an operational discharge.

3.3 The response resources shall, as appropriate, include:

3.3.1 One thousand feet of containment boom (or, for complexes with marine transfer components, 1,000 feet of containment boom or two times the length of the largest vessel that regularly conducts oil transfers to or from the facility, whichever is greater), and a means of deploying it within 1 hour of the discovery of a discharge;

3.3.2 Oil recovery devices with an effective daily recovery capacity equal to the amount of oil discharged in a small discharge or greater which is available at the

facility within 2 hours of the detection of an oil discharge; and

3.3.3 Oil storage capacity for recovered oily material indicated in section 12.2 of this appendix.

4.0 Determining Response Resources Required for Medium Discharges—Petroleum Oils and Non-Petroleum Oils Other Than Animal Fats and Vegetable Oils

4.1 A facility owner or operator shall identify sufficient response resources available, by contract or other approved means as described in §112.2, to respond to a medium discharge of oil for that facility. This will require response resources capable of containing and collecting up to 36,000 gallons of oil or 10 percent of the worst case discharge, whichever is less. All equipment identified must be designed to operate in the applicable operating environment specified in Table 1 of this appendix.

4.2 Complexes that are regulated by EPA and the USCG must also consider planning quantities for the transportation-related transfer portion of the facility.

4.2.1 *Petroleum oils.* The USCG planning level that corresponds to EPA's ''medium discharge'' is termed ''the maximum most probable discharge.'' The USCG rule found at 33 CFR part 154 defines ''the maximum most probable discharge'' as a discharge of 1,200 barrels (50,400 gallons) or 10 percent of the worst case discharge, whichever is less. Owners or operators of complexes that handle, store, or transport petroleum oils must compare calculated discharge volumes for a medium discharge and a maximum most probable discharge, and plan for whichever quantity is greater.

4.2.2 *Non-petroleum oils other than animal fats and vegetable oils.* Owners or operators of complexes that handle, store, or transport non-petroleum oils other than animal fats and vegetable oils must plan for oil discharge volumes for a medium discharge. For non-petroleum oils, there is no USCG planning level that directly corresponds to EPA's ''medium discharge.''

4.3 Oil recovery devices identified to meet the applicable medium discharge volume planning criteria must be located such that they are capable of arriving on-scene within 6 hours in higher volume port areas and the Great Lakes and within 12 hours in all other areas. Higher volume port areas and Great Lakes areas are defined in section 1.1 of appendix C to this part.

4.4 Because rapid control, containment, and removal of oil are critical to reduce discharge impact, the owner or operator must determine response resources using an effective daily recovery capacity for oil recovery devices equal to 50 percent of the planning volume applicable for the facility as determined in section 4.1 of this appendix. The effective daily recovery capacity for oil recovery devices identified in the plan must be determined using the criteria in section 6 of this appendix.

4.5 In addition to oil recovery capacity, the plan shall, as appropriate, identify sufficient quantity of containment boom available, by contract or other approved means as described in §112.2, to arrive within the required response times for oil collection and containment and for protection of fish and wildlife and sensitive environments. For further description of fish and wildlife and sensitive environments, see Appendices I, II, and III to DOC/NOAA's ''Guidance for Facility and Vessel Response Plans: Fish and Wildlife and Sensitive Environments'' (see appendix E to this part, section 13, for availability) and the applicable ACP. Although 40 CFR part 112 does not set required quantities of boom for oil collection and containment, the response plan shall identify and ensure, by contract or other approved means as described in §112.2, the availability of the quantity of boom identified in the plan for this purpose.

4.6 The plan must indicate the availability of temporary storage capacity to meet section 12.2 of this appendix. If available storage capacity is insufficient to meet this level, then the effective daily recovery capacity must be derated (downgraded) to the limits of the available storage capacity.

4.7 The following is an example of a medium discharge volume planning calculation for equipment identification in a higher volume port area: The facility's largest aboveground storage tank volume is 840,000 gallons. Ten percent of this capacity is 84,000 gallons. Because 10 percent of the facility's largest tank, or 84,000 gallons, is greater than 36,000 gallons, 36,000 gallons is used as the planning volume. The effective daily recovery capacity is 50 percent of the planning volume, or 18,000 gallons per day. The ability of oil recovery devices to meet this capacity must be calculated using the procedures in section 6 of this appendix. Temporary storage capacity available on-scene must equal twice the daily recovery capacity as indicated in section 12.2 of this appendix, or 36,000 gallons per day. This is the information the facility owner or operator must use to identify and ensure the availability of the required response resources, by contract or other approved means as described in §112.2. The facility owner shall also identify how much boom is available for use.

5.0 Determining Response Resources Required for the Worst Case Discharge to the Maximum Extent Practicable

5.1 A facility owner or operator shall identify and ensure the availability of, by

contract or other approved means as described in §112.2, sufficient response resources to respond to the worst case discharge of oil to the maximum extent practicable. Sections 7 and 10 of this appendix describe the method to determine the necessary response resources. Worksheets are provided as Attachments E–1 and E–2 at the end of this appendix to simplify the procedures involved in calculating the planning volume for response resources for the worst case discharge.

5.2 Complexes that are regulated by EPA and the USCG must also consider planning for the worst case discharge at the transportation-related portion of the facility. The USCG requires that transportation-related facility owners or operators use a different calculation for the worst case discharge in the revisions to 33 CFR part 154. Owners or operators of complex facilities that are regulated by EPA and the USCG must compare both calculations of worst case discharge derived by EPA and the USCG and plan for whichever volume is greater.

5.3 Oil discharge response resources identified in the response plan and available, by contract or other approved means as described in §112.2, to meet the applicable worst case discharge planning volume must be located such that they are capable of arriving at the scene of a discharge within the times specified for the applicable response tier listed as follows

	Tier 1 (in hours)	Tier 2 (in hours)	Tier 3 (in hours)
Higher volume port areas	6	30	54
Great Lakes	12	36	60
All other river and canal, inland, and nearshore areas	12	36	60

The three levels of response tiers apply to the amount of time in which facility owners or operators must plan for response resources to arrive at the scene of a discharge to respond to the worst case discharge planning volume. For example, at a worst case discharge in an inland area, the first tier of response resources (*i.e.,* that amount of on-water and shoreline cleanup capacity necessary to respond to the fraction of the worst case discharge as indicated through the series of steps described in sections 7.2 and 7.3 or sections 10.2 and 10.3 of this appendix) would arrive at the scene of the discharge within 12 hours; the second tier of response resources would arrive within 36 hours; and the third tier of response resources would arrive within 60 hours.

5.4 The effective daily recovery capacity for oil recovery devices identified in the response plan must be determined using the criteria in section 6 of this appendix. A facility owner or operator shall identify the storage locations of all response resources used for each tier. The owner or operator of a facility whose required daily recovery capacity exceeds the applicable contracting caps in Table 5 of this appendix shall, as appropriate, identify sources of additional equipment, their location, and the arrangements made to obtain this equipment during a response. The owner or operator of a facility whose calculated planning volume exceeds the applicable contracting caps in Table 5 of this appendix shall, as appropriate, identify sources of additional equipment equal to twice the cap listed in Tier 3 or the amount necessary to reach the calculated planning volume, whichever is lower. The resources identified above the cap shall be capable of arriving on-scene not later than the Tier 3 response times in section 5.3 of this appendix. No contract is required. While general listings of available response equipment may be used to identify additional sources (i.e., ''public'' resources vs. ''private'' resources), the response plan shall identify the specific sources, locations, and quantities of equipment that a facility owner or operator has considered in his or her planning. When listing USCG-classified oil spill removal organization(s) that have sufficient removal capacity to recover the volume above the response capacity cap for the specific facility, as specified in Table 5 of this appendix, it is not necessary to list specific quantities of equipment.

5.5 A facility owner or operator shall identify the availability of temporary storage capacity to meet section 12.2 of this appendix. If available storage capacity is insufficient, then the effective daily recovery capacity must be derated (downgraded) to the limits of the available storage capacity.

5.6 When selecting response resources necessary to meet the response plan requirements, the facility owner or operator shall, as appropriate, ensure that a portion of those resources is capable of being used in close-to-shore response activities in shallow water. For any EPA-regulated facility that is required to plan for response in shallow water, at least 20 percent of the on-water response equipment identified for the applicable operating area shall, as appropriate, be capable of operating in water of 6 feet or less depth.

5.7 In addition to oil spill recovery devices, a facility owner or operator shall identify sufficient quantities of boom that are available, by contract or other approved means as described in §112.2, to arrive on-

scene within the specified response times for oil containment and collection. The specific quantity of boom required for collection and containment will depend on the facility-specific information and response strategies employed. A facility owner or operator shall, as appropriate, also identify sufficient quantities of oil containment boom to protect fish and wildlife and sensitive environments. For further description of fish and wildlife and sensitive environments, see Appendices I, II, and III to DOC/NOAA's ''Guidance for Facility and Vessel Response Plans: Fish and Wildlife and Sensitive Environments'' (see appendix E to this part, section 13, for availability), and the applicable ACP. Refer to this guidance document for the number of days and geographic areas (*i.e.*, operating environments) specified in Table 2 and Table 6 of this appendix.

5.8 A facility owner or operator shall also identify, by contract or other approved means as described in §112.2, the availability of an oil spill removal organization(s) (as described in §112.2) capable of responding to a shoreline cleanup operation involving the calculated volume of oil and emulsified oil that might impact the affected shoreline. The volume of oil that shall, as appropriate, be planned for is calculated through the application of factors contained in Tables 2, 3, 6, and 7 of this appendix. The volume calculated from these tables is intended to assist the facility owner or operator to identify an oil spill removal organization with sufficient resources and expertise.

6.0 Determining Effective Daily Recovery Capacity for Oil Recovery Devices

6.1 Oil recovery devices identified by a facility owner or operator must be identified by the manufacturer, model, and effective daily recovery capacity. These capacities must be used to determine whether there is sufficient capacity to meet the applicable planning criteria for a small discharge, a medium discharge, and a worst case discharge to the maximum extent practicable.

6.2 To determine the effective daily recovery capacity of oil recovery devices, the formula listed in section 6.2.1 of this appendix shall be used. This formula considers potential limitations due to available daylight, weather, sea state, and percentage of emulsified oil in the recovered material. The RA may assign a lower efficiency factor to equipment listed in a response plan if it is determined that such a reduction is warranted.

6.2.1 The following formula shall be used to calculate the effective daily recovery capacity:

$R = T \times 24 \text{ hours} \times E$

where:

R—Effective daily recovery capacity;

T—Throughput rate in barrels per hour (nameplate capacity); and

E—20 percent efficiency factor (or lower factor as determined by the Regional Administrator).

6.2.2 For those devices in which the pump limits the throughput of liquid, throughput rate shall be calculated using the pump capacity.

6.2.3 For belt or moptype devices, the throughput rate shall be calculated using the speed of the belt or mop through the device, assumed thickness of oil adhering to or collected by the device, and surface area of the belt or mop. For purposes of this calculation, the assumed thickness of oil will be ¼ inch.

6.2.4 Facility owners or operators that include oil recovery devices whose throughput is not measurable using a pump capacity or belt/mop speed may provide information to support an alternative method of calculation. This information must be submitted following the procedures in section 6.3.2 of this appendix.

6.3 As an alternative to section 6.2 of this appendix, a facility owner or operator may submit adequate evidence that a different effective daily recovery capacity should be applied for a specific oil recovery device. Adequate evidence is actual verified performance data in discharge conditions or tests using American Society of Testing and Materials (ASTM) Standard F 631–99, F 808–83 (1999), or an equivalent test approved by EPA as deemed appropriate (see Appendix E to this part, section 13, for general availability of documents).

6.3.1 The following formula must be used to calculate the effective daily recovery capacity under this alternative:

$R = D \times U$

where:

R—Effective daily recovery capacity;

D—Average Oil Recovery Rate in barrels per hour (Item 26 in F 808–83; Item 13.2.16 in F 631–99; or actual performance data); and

U—Hours per day that equipment can operate under discharge conditions. Ten hours per day must be used unless a facility owner or operator can demonstrate that the recovery operation can be sustained for longer periods.

6.3.2 A facility owner or operator submitting a response plan shall provide data that supports the effective daily recovery capacities for the oil recovery devices listed. The following is an example of these calculations:

(1) A weir skimmer identified in a response plan has a manufacturer's rated throughput at the pump of 267 gallons per minute (gpm).

267 gpm=381 barrels per hour (bph)

R=381 bph×24 hr/day×0.2=1,829 barrels per day

(2) After testing using ASTM procedures, the skimmer's oil recovery rate is determined to be 220 gpm. The facility owner or operator identifies sufficient resources available to support operations for 12 hours per day.

220 gpm=314 bph
R=314 bph×12 hr/day=3,768 barrels per day

(3) The facility owner or operator will be able to use the higher capacity if sufficient temporary oil storage capacity is available. Determination of alternative efficiency factors under section 6.2 of this appendix or the acceptability of an alternative effective daily recovery capacity under section 6.3 of this appendix will be made by the Regional Administrator as deemed appropriate.

7.0 Calculating Planning Volumes for a Worst Case Discharge—Petroleum Oils and Non-Petroleum Oils Other Than Animal Fats and Vegetable Oils

7.1 A facility owner or operator shall plan for a response to the facility's worst case discharge. The planning for on-water oil recovery must take into account a loss of some oil to the environment due to evaporative and natural dissipation, potential increases in volume due to emulsification, and the potential for deposition of oil on the shoreline. The procedures for non-petroleum oils other than animal fats and vegetable oils are discussed in section 7.7 of this appendix.

7.2 The following procedures must be used by a facility owner or operator in determining the required on-water oil recovery capacity:

7.2.1 The following must be determined: the worst case discharge volume of oil in the facility; the appropriate group(s) for the types of oil handled, stored, or transported at the facility [persistent (Groups 2, 3, 4, 5) or non-persistent (Group 1)]; and the facility's specific operating area. See sections 1.2.3 and 1.2.8 of this appendix for the definitions of non-persistent and persistent oils, respectively. Facilities that handle, store, or transport oil from different oil groups must calculate each group separately, unless the oil group constitutes 10 percent or less by volume of the facility's total oil storage capacity. This information is to be used with Table 2 of this appendix to determine the percentages of the total volume to be used for removal capacity planning. Table 2 of this appendix divides the volume into three categories: oil lost to the environment; oil deposited on the shoreline; and oil available for on-water recovery.

7.2.2 The on-water oil recovery volume shall, as appropriate, be adjusted using the appropriate emulsification factor found in Table 3 of this appendix. Facilities that handle, store, or transport oil from different petroleum groups must compare the on-water recovery volume for each oil group (unless the oil group constitutes 10 percent or less by volume of the facility's total storage capacity) and use the calculation that results in the largest on-water oil recovery volume to plan for the amount of response resources for a worst case discharge.

7.2.3 The adjusted volume is multiplied by the on-water oil recovery resource mobilization factor found in Table 4 of this appendix from the appropriate operating area and response tier to determine the total on-water oil recovery capacity in barrels per day that must be identified or contracted to arrive on-scene within the applicable time for each response tier. Three tiers are specified. For higher volume port areas, the contracted tiers of resources must be located such that they are capable of arriving on-scene within 6 hours for Tier 1, 30 hours for Tier 2, and 54 hours for Tier 3 of the discovery of an oil discharge. For all other rivers and canals, inland, nearshore areas, and the Great Lakes, these tiers are 12, 36, and 60 hours.

7.2.4 The resulting on-water oil recovery capacity in barrels per day for each tier is used to identify response resources necessary to sustain operations in the applicable operating area. The equipment shall be capable of sustaining operations for the time period specified in Table 2 of this appendix. The facility owner or operator shall identify and ensure the availability, by contract or other approved means as described in §112.2, of sufficient oil spill recovery devices to provide the effective daily oil recovery capacity required. If the required capacity exceeds the applicable cap specified in Table 5 of this appendix, then a facility owner or operator shall ensure, by contract or other approved means as described in §112.2, only for the quantity of resources required to meet the cap, but shall identify sources of additional resources as indicated in section 5.4 of this appendix. The owner or operator of a facility whose planning volume exceeded the cap in 1993 must make arrangements to identify and ensure the availability, by contract or other approved means as described in §112.2, for additional capacity to be under contract by 1998 or 2003, as appropriate. For a facility that handles multiple groups of oil, the required effective daily recovery capacity for each oil group is calculated before applying the cap. The oil group calculation resulting in the largest on-water recovery volume must be used to plan for the amount of response resources for a worst case discharge, unless the oil group comprises 10 percent or less by volume of the facility's total oil storage capacity.

7.3 The procedures discussed in sections 7.3.1–7.3.3 of this appendix must be used to calculate the planning volume for identifying shoreline cleanup capacity (for Group 1 through Group 4 oils).

7.3.1 The following must be determined: the worst case discharge volume of oil for

the facility; the appropriate group(s) for the types of oil handled, stored, or transported at the facility [persistent (Groups 2, 3, or 4) or non-persistent (Group 1)]; and the geographic area(s) in which the facility operates (*i.e.*, operating areas). For a facility handling, storing, or transporting oil from different groups, each group must be calculated separately. Using this information, Table 2 of this appendix must be used to determine the percentages of the total volume to be used for shoreline cleanup resource planning.

7.3.2 The shoreline cleanup planning volume must be adjusted to reflect an emulsification factor using the same procedure as described in section 7.2.2 of this appendix.

7.3.3 The resulting volume shall be used to identify an oil spill removal organization with the appropriate shoreline cleanup capability.

7.4 A response plan must identify response resources with fire fighting capability. The owner or operator of a facility that handles, stores, or transports Group 1 through Group 4 oils that does not have adequate fire fighting resources located at the facility or that cannot rely on sufficient local fire fighting resources must identify adequate fire fighting resources. The facility owner or operator shall ensure, by contract or other approved means as described in §112.2, the availability of these resources. The response plan must also identify an individual located at the facility to work with the fire department for Group 1 through Group 4 oil fires. This individual shall also verify that sufficient well-trained fire fighting resources are available within a reasonable response time to a worst case scenario. The individual may be the qualified individual identified in the response plan or another appropriate individual located at the facility.

7.5 The following is an example of the procedure described above in sections 7.2 and 7.3 of this appendix: A facility with a 270,000 barrel (11.3 million gallons) capacity for #6 oil (specific gravity 0.96) is located in a higher volume port area. The facility is on a peninsula and has docks on both the ocean and bay sides. The facility has four aboveground oil storage tanks with a combined total capacity of 80,000 barrels (3.36 million gallons) and no secondary containment. The remaining facility tanks are inside secondary containment structures. The largest aboveground oil storage tank (90,000 barrels or 3.78 million gallons) has its own secondary containment. Two 50,000 barrel (2.1 million gallon) tanks (that are not connected by a manifold) are within a common secondary containment tank area, which is capable of holding 100,000 barrels (4.2 million gallons) plus sufficient freeboard.

7.5.1 The worst case discharge for the facility is calculated by adding the capacity of all aboveground oil storage tanks without secondary containment (80,000 barrels) plus the capacity of the largest aboveground oil storage tank inside secondary containment. The resulting worst case discharge volume is 170,000 barrels or 7.14 million gallons.

7.5.2 Because the requirements for Tiers 1, 2, and 3 for inland and nearshore exceed the caps identified in Table 5 of this appendix, the facility owner will contract for a response to 10,000 barrels per day (bpd) for Tier 1, 20,000 bpd for Tier 2, and 40,000 bpd for Tier 3. Resources for the remaining 7,850 bpd for Tier 1, 9,750 bpd for Tier 2, and 7,600 bpd for Tier 3 shall be identified but need not be contracted for in advance. The facility owner or operator shall, as appropriate, also identify or contract for quantities of boom identified in their response plan for the protection of fish and wildlife and sensitive environments within the area potentially impacted by a worst case discharge from the facility. For further description of fish and wildlife and sensitive environments, see Appendices I, II, and III to DOC/NOAA's ''Guidance for Facility and Vessel Response Plans: Fish and Wildlife and Sensitive Environments,'' (see appendix E to this part, section 13, for availability) and the applicable ACP. Attachment C–III to Appendix C provides a method for calculating a planning distance to fish and wildlife and sensitive environments and public drinking water intakes that may be impacted in the event of a worst case discharge.

7.6 The procedures discussed in sections 7.6.1–7.6.3 of this appendix must be used to determine appropriate response resources for facilities with Group 5 oils.

7.6.1 The owner or operator of a facility that handles, stores, or transports Group 5 oils shall, as appropriate, identify the response resources available by contract or other approved means, as described in §112.2. The equipment identified in a response plan shall, as appropriate, include:

(1) Sonar, sampling equipment, or other methods for locating the oil on the bottom or suspended in the water column;

(2) Containment boom, sorbent boom, silt curtains, or other methods for containing the oil that may remain floating on the surface or to reduce spreading on the bottom;

(3) Dredges, pumps, or other equipment necessary to recover oil from the bottom and shoreline;

(4) Equipment necessary to assess the impact of such discharges; and

(5) Other appropriate equipment necessary to respond to a discharge involving the type of oil handled, stored,, or transported.

7.6.2 Response resources identified in a response plan for a facility that handles, stores, or transports Group 5 oils under section 7.6.1 of this appendix shall be capable of being deployed (on site) within 24 hours of discovery of a discharge to the area where the facility is operating.

7.6.3 A response plan must identify response resources with fire fighting capability. The owner or operator of a facility that handles, stores, or transports Group 5 oils that does not have adequate fire fighting resources located at the facility or that cannot rely on sufficient local fire fighting resources must identify adequate fire fighting resources. The facility owner or operator shall ensure, by contract or other approved means as described in §112.2, the availability of these resources. The response plan shall also identify an individual located at the facility to work with the fire department for Group 5 oil fires. This individual shall also verify that sufficient well-trained fire fighting resources are available within a reasonable response time to respond to a worst case discharge. The individual may be the qualified individual identified in the response plan or another appropriate individual located at the facility.

7.7 *Non-petroleum oils other than animal fats and vegetable oils.* The procedures described in sections 7.7.1 through 7.7.5 of this appendix must be used to determine appropriate response plan development and evaluation criteria for facilities that handle, store, or transport non-petroleum oils other than animal fats and vegetable oils. Refer to section 11 of this appendix for information on the limitations on the use of chemical agents for inland and nearshore areas.

7.7.1 An owner or operator of a facility that handles, stores, or transports non-petroleum oils other than animal fats and vegetable oils must provide information in his or her plan that identifies:

(1) Procedures and strategies for responding to a worst case discharge to the maximum extent practicable; and

(2) Sources of the equipment and supplies necessary to locate, recover, and mitigate such a discharge.

7.7.2 An owner or operator of a facility that handles, stores, or transports non-petroleum oils other than animal fats and vegetable oils must ensure that any equipment identified in a response plan is capable of operating in the conditions expected in the geographic area(s) (*i.e.*, operating environments) in which the facility operates using the criteria in Table 1 of this appendix. When evaluating the operability of equipment, the facility owner or operator must consider limitations that are identified in the appropriate ACPs, including:

(1) Ice conditions;

(2) Debris;

(3) Temperature ranges; and

(4) Weather-related visibility.

7.7.3 The owner or operator of a facility that handles, stores, or transports non-petroleum oils other than animal fats and vegetable oils must identify the response resources that are available by contract or other approved means, as described in §112.2. The equipment described in the response plan shall, as appropriate, include:

(1) Containment boom, sorbent boom, or other methods for containing oil floating on the surface or to protect shorelines from impact;

(2) Oil recovery devices appropriate for the type of non-petroleum oil carried; and

(3) Other appropriate equipment necessary to respond to a discharge involving the type of oil carried.

7.7.4 Response resources identified in a response plan according to section 7.7.3 of this appendix must be capable of commencing an effective on-scene response within the applicable tier response times in section 5.3 of this appendix.

7.7.5 A response plan must identify response resources with fire fighting capability. The owner or operator of a facility that handles, stores, or transports non-petroleum oils other than animal fats and vegetable oils that does not have adequate fire fighting resources located at the facility or that cannot rely on sufficient local fire fighting resources must identify adequate fire fighting resources. The owner or operator shall ensure, by contract or other approved means as described in §112.2, the availability of these resources. The response plan must also identify an individual located at the facility to work with the fire department for fires of these oils. This individual shall also verify that sufficient well-trained fire fighting resources are available within a reasonable response time to a worst case scenario. The individual may be the qualified individual identified in the response plan or another appropriate individual located at the facility.

8.0 Determining Response Resources Required for Small Discharges—Animal Fats and Vegetable Oils

8.1 A facility owner or operator shall identify sufficient response resources available, by contract or other approved means as described in §112.2, to respond to a small discharge of animal fats or vegetable oils. A small discharge is defined as any discharge volume less than or equal to 2,100 gallons, but not to exceed the calculated worst case discharge. The equipment must be designed to function in the operating environment at the point of expected use.

8.2 Complexes that are regulated by EPA and the USCG must also consider planning quantities for the marine transportation-related portion of the facility.

8.2.1 The USCG planning level that corresponds to EPA's ''small discharge'' is termed ''the average most probable discharge.'' A USCG rule found at 33 CFR 154.1020 defines ''the average most probable discharge'' as the lesser of 50 barrels (2,100 gallons) or 1 percent of the volume of the worst case discharge. Owners or operators of

complexes that handle, store, or transport animal fats and vegetable oils must compare oil discharge volumes for a small discharge and an average most probable discharge, and plan for whichever quantity is greater.

8.3 The response resources shall, as appropriate, include:

8.3.1 One thousand feet of containment boom (or, for complexes with marine transfer components, 1,000 feet of containment boom or two times the length of the largest vessel that regularly conducts oil transfers to or from the facility, whichever is greater), and a means of deploying it within 1 hour of the discovery of a discharge;

8.3.2 Oil recovery devices with an effective daily recovery capacity equal to the amount of oil discharged in a small discharge or greater which is available at the facility within 2 hours of the detection of a discharge; and

8.3.3 Oil storage capacity for recovered oily material indicated in section 12.2 of this appendix.

9.0 Determining Response Resources Required for Medium Discharges—Animal Fats and Vegetable Oils

9.1 A facility owner or operator shall identify sufficient response resources available, by contract or other approved means as described in §112.2, to respond to a medium discharge of animal fats or vegetable oils for that facility. This will require response resources capable of containing and collecting up to 36,000 gallons of oil or 10 percent of the worst case discharge, whichever is less. All equipment identified must be designed to operate in the applicable operating environment specified in Table 1 of this appendix.

9.2 Complexes that are regulated by EPA and the USCG must also consider planning quantities for the transportation-related transfer portion of the facility. Owners or operators of complexes that handle, store, or transport animal fats or vegetable oils must plan for oil discharge volumes for a medium discharge. For non-petroleum oils, there is no USCG planning level that directly corresponds to EPA's ''medium discharge.'' Although the USCG does not have planning requirements for medium discharges, they do have requirements (at 33 CFR 154.545) to identify equipment to contain oil resulting from an operational discharge.

9.3 Oil recovery devices identified to meet the applicable medium discharge volume planning criteria must be located such that they are capable of arriving on-scene within 6 hours in higher volume port areas and the Great Lakes and within 12 hours in all other areas. Higher volume port areas and Great Lakes areas are defined in section 1.1 of appendix C to this part.

9.4 Because rapid control, containment, and removal of oil are critical to reduce discharge impact, the owner or operator must determine response resources using an effective daily recovery capacity for oil recovery devices equal to 50 percent of the planning volume applicable for the facility as determined in section 9.1 of this appendix. The effective daily recovery capacity for oil recovery devices identified in the plan must be determined using the criteria in section 6 of this appendix.

9.5 In addition to oil recovery capacity, the plan shall, as appropriate, identify sufficient quantity of containment boom available, by contract or other approved means as described in §112.2, to arrive within the required response times for oil collection and containment and for protection of fish and wildlife and sensitive environments. For further description of fish and wildlife and sensitive environments, see Appendices I, II, and III to DOC/NOAA's ''Guidance for Facility and Vessel Response Plans: Fish and Wildlife and Sensitive Environments'' (59 FR 14713–22, March 29, 1994) and the applicable ACP. Although 40 CFR part 112 does not set required quantities of boom for oil collection and containment, the response plan shall identify and ensure, by contract or other approved means as described in §112.2, the availability of the quantity of boom identified in the plan for this purpose.

9.6 The plan must indicate the availability of temporary storage capacity to meet section 12.2 of this appendix. If available storage capacity is insufficient to meet this level, then the effective daily recovery capacity must be derated (downgraded) to the limits of the available storage capacity.

9.7 The following is an example of a medium discharge volume planning calculation for equipment identification in a higher volume port area:

The facility's largest aboveground storage tank volume is 840,000 gallons. Ten percent of this capacity is 84,000 gallons. Because 10 percent of the facility's largest tank, or 84,000 gallons, is greater than 36,000 gallons, 36,000 gallons is used as the planning volume. The effective daily recovery capacity is 50 percent of the planning volume, or 18,000 gallons per day. The ability of oil recovery devices to meet this capacity must be calculated using the procedures in section 6 of this appendix. Temporary storage capacity available on-scene must equal twice the daily recovery capacity as indicated in section 12.2 of this appendix, or 36,000 gallons per day. This is the information the facility owner or operator must use to identify and ensure the availability of the required response resources, by contract or other approved means as described in §112.2. The facility owner shall also identify how much boom is available for use.

10.0 Calculating Planning Volumes for a Worst Case Discharge—Animal Fats and Vegetable Oils.

10.1 A facility owner or operator shall plan for a response to the facility's worst case discharge. The planning for on-water oil recovery must take into account a loss of some oil to the environment due to physical, chemical, and biological processes, potential increases in volume due to emulsification, and the potential for deposition of oil on the shoreline or on sediments. The response planning procedures for animal fats and vegetable oils are discussed in section 10.7 of this appendix. You may use alternate response planning procedures for animal fats and vegetable oils if those procedures result in environmental protection equivalent to that provided by the procedures in section 10.7 of this appendix.

10.2 The following procedures must be used by a facility owner or operator in determining the required on-water oil recovery capacity:

10.2.1 The following must be determined: the worst case discharge volume of oil in the facility; the appropriate group(s) for the types of oil handled, stored, or transported at the facility (Groups A, B, C); and the facility's specific operating area. See sections 1.2.1 and 1.2.9 of this appendix for the definitions of animal fats and vegetable oils and groups thereof. Facilities that handle, store, or transport oil from different oil groups must calculate each group separately, unless the oil group constitutes 10 percent or less by volume of the facility's total oil storage capacity. This information is to be used with Table 6 of this appendix to determine the percentages of the total volume to be used for removal capacity planning. Table 6 of this appendix divides the volume into three categories: oil lost to the environment; oil deposited on the shoreline; and oil available for on-water recovery.

10.2.2 The on-water oil recovery volume shall, as appropriate, be adjusted using the appropriate emulsification factor found in Table 7 of this appendix. Facilities that handle, store, or transport oil from different groups must compare the on-water recovery volume for each oil group (unless the oil group constitutes 10 percent or less by volume of the facility's total storage capacity) and use the calculation that results in the largest on-water oil recovery volume to plan for the amount of response resources for a worst case discharge.

10.2.3 The adjusted volume is multiplied by the on-water oil recovery resource mobilization factor found in Table 4 of this appendix from the appropriate operating area and response tier to determine the total on-water oil recovery capacity in barrels per day that must be identified or contracted to arrive on-scene within the applicable time for each response tier. Three tiers are specified. For higher volume port areas, the contracted tiers of resources must be located such that they are capable of arriving on-scene within 6 hours for Tier 1, 30 hours for Tier 2, and 54 hours for Tier 3 of the discovery of a discharge. For all other rivers and canals, inland, nearshore areas, and the Great Lakes, these tiers are 12, 36, and 60 hours.

10.2.4 The resulting on-water oil recovery capacity in barrels per day for each tier is used to identify response resources necessary to sustain operations in the applicable operating area. The equipment shall be capable of sustaining operations for the time period specified in Table 6 of this appendix. The facility owner or operator shall identify and ensure, by contract or other approved means as described in §112.2, the availability of sufficient oil spill recovery devices to provide the effective daily oil recovery capacity required. If the required capacity exceeds the applicable cap specified in Table 5 of this appendix, then a facility owner or operator shall ensure, by contract or other approved means as described in §112.2, only for the quantity of resources required to meet the cap, but shall identify sources of additional resources as indicated in section 5.4 of this appendix. The owner or operator of a facility whose planning volume exceeded the cap in 1998 must make arrangements to identify and ensure, by contract or other approved means as described in §112.2, the availability of additional capacity to be under contract by 2003, as appropriate. For a facility that handles multiple groups of oil, the required effective daily recovery capacity for each oil group is calculated before applying the cap. The oil group calculation resulting in the largest on-water recovery volume must be used to plan for the amount of response resources for a worst case discharge, unless the oil group comprises 10 percent or less by volume of the facility's oil storage capacity.

10.3 The procedures discussed in sections 10.3.1 through 10.3.3 of this appendix must be used to calculate the planning volume for identifying shoreline cleanup capacity (for Groups A and B oils).

10.3.1 The following must be determined: the worst case discharge volume of oil for the facility; the appropriate group(s) for the types of oil handled, stored, or transported at the facility (Groups A or B); and the geographic area(s) in which the facility operates (i.e., operating areas). For a facility handling, storing, or transporting oil from different groups, each group must be calculated separately. Using this information, Table 6 of this appendix must be used to determine the percentages of the total volume to be used for shoreline cleanup resource planning.

10.3.2 The shoreline cleanup planning volume must be adjusted to reflect an emulsification factor using the same procedure as described in section 10.2.2 of this appendix.

10.3.3 The resulting volume shall be used to identify an oil spill removal organization with the appropriate shoreline cleanup capability.

10.4 A response plan must identify response resources with fire fighting capability appropriate for the risk of fire and explosion at the facility from the discharge or threat of discharge of oil. The owner or operator of a facility that handles, stores, or transports Group A or B oils that does not have adequate fire fighting resources located at the facility or that cannot rely on sufficient local fire fighting resources must identify adequate fire fighting resources. The facility owner or operator shall ensure, by contract or other approved means as described in § 112.2, the availability of these resources. The response plan must also identify an individual to work with the fire department for Group A or B oil fires. This individual shall also verify that sufficient well-trained fire fighting resources are available within a reasonable response time to a worst case scenario. The individual may be the qualified individual identified in the response plan or another appropriate individual located at the facility.

10.5 The following is an example of the procedure described in sections 10.2 and 10.3 of this appendix. A facility with a 37.04 million gallon (881,904 barrel) capacity of several types of vegetable oils is located in the Inland Operating Area. The vegetable oil with the highest specific gravity stored at the facility is soybean oil (specific gravity 0.922, Group B vegetable oil). The facility has ten aboveground oil storage tanks with a combined total capacity of 18 million gallons (428,571 barrels) and without secondary containment. The remaining facility tanks are inside secondary containment structures. The largest aboveground oil storage tank (3 million gallons or 71,428 barrels) has its own secondary containment. Two 2.1 million gallon (50,000 barrel) tanks (that are not connected by a manifold) are within a common secondary containment tank area, which is capable of holding 4.2 million gallons (100,000 barrels) plus sufficient freeboard.

10.5.1 The worst case discharge for the facility is calculated by adding the capacity of all aboveground vegetable oil storage tanks without secondary containment (18.0 million gallons) plus the capacity of the largest aboveground storage tank inside secondary containment (3.0 million gallons). The resulting worst case discharge is 21 million gallons or 500,000 barrels.

10.5.2 With a specific worst case discharge identified, the planning volume for on-water recovery can be identified as follows:

Worst case discharge: 21 million gallons (500,000 barrels) of Group B vegetable oil
Operating Area: Inland
Planned percent recovered floating vegetable oil (from Table 6, column Nearshore/Inland/Great Lakes): Inland, Group B is 20%
Emulsion factor (from Table 7): 2.0
Planning volumes for on-water recovery: 21,000,000 gallons × 0.2 × 2.0 = 8,400,000 gallons or 200,000 barrels.
Determine required resources for on-water recovery for each of the three tiers using mobilization factors (from Table 4, column Inland/Nearshore/Great Lakes)

Inland Operating Area	Tier 1	Tier 2	Tier 3
Mobilization factor by which you multiply planning volume	.15	.25	.40
Estimated Daily Recovery Capacity (bbls)	30,000	50,000	80,000

10.5.3 Because the requirements for On-Water Recovery Resources for Tiers 1, 2, and 3 for Inland Operating Area exceed the caps identified in Table 5 of this appendix, the facility owner will contract for a response of 12,500 barrels per day (bpd) for Tier 1, 25,000 bpd for Tier 2, and 50,000 bpd for Tier 3. Resources for the remaining 17,500 bpd for Tier 1, 25,000 bpd for Tier 2, and 30,000 bpd for Tier 3 shall be identified but need not be contracted for in advance.

10.5.4 With the specific worst case discharge identified, the planning volume of onshore recovery can be identified as follows:

Worst case discharge: 21 million gallons (500,000 barrels) of Group B vegetable oil
Operating Area: Inland
Planned percent recovered floating vegetable oil from onshore (from Table 6, column Nearshore/Inland/Great Lakes): Inland, Group B is 65%
Emulsion factor (from Table 7): 2.0
Planning volumes for shoreline recovery: 21,000,000 gallons × 0.65 × 2.0 = 27,300,000 gallons or 650,000 barrels

10.5.5 The facility owner or operator shall, as appropriate, also identify or contract for quantities of boom identified in the response plan for the protection of fish and wildlife and sensitive environments within the area potentially impacted by a worst case discharge from the facility. For further description of fish and wildlife and sensitive environments, see Appendices I, II, and III to DOC/NOAA's ''Guidance for Facility and Vessel Response Plans: Fish and Wildlife and Sensitive Environments,'' (see Appendix E to this part, section 13, for availability) and the applicable ACP. Attachment C–III to Appendix C provides a method for calculating a planning distance to fish and wildlife and sensitive environments and public drinking

water intakes that may be adversely affected in the event of a worst case discharge.

10.6 The procedures discussed in sections 10.6.1 through 10.6.3 of this appendix must be used to determine appropriate response resources for facilities with Group C oils.

10.6.1 The owner or operator of a facility that handles, stores, or transports Group C oils shall, as appropriate, identify the response resources available by contract or other approved means, as described in §112.2. The equipment identified in a response plan shall, as appropriate, include:

(1) Sonar, sampling equipment, or other methods for locating the oil on the bottom or suspended in the water column;

(2) Containment boom, sorbent boom, silt curtains, or other methods for containing the oil that may remain floating on the surface or to reduce spreading on the bottom;

(3) Dredges, pumps, or other equipment necessary to recover oil from the bottom and shoreline;

(4) Equipment necessary to assess the impact of such discharges; and

(5) Other appropriate equipment necessary to respond to a discharge involving the type of oil handled, stored, or transported.

10.6.2 Response resources identified in a response plan for a facility that handles, stores, or transports Group C oils under section 10.6.1 of this appendix shall be capable of being deployed on scene within 24 hours of discovery of a discharge.

10.6.3 A response plan must identify response resources with fire fighting capability. The owner or operator of a facility that handles, stores, or transports Group C oils that does not have adequate fire fighting resources located at the facility or that cannot rely on sufficient local fire fighting resources must identify adequate fire fighting resources. The owner or operator shall ensure, by contract or other approved means as described in §112.2, the availability of these resources. The response plan shall also identify an individual located at the facility to work with the fire department for Group C oil fires. This individual shall also verify that sufficient well-trained fire fighting resources are available within a reasonable response time to respond to a worst case discharge. The individual may be the qualified individual identified in the response plan or another appropriate individual located at the facility.

10.7 The procedures described in sections 10.7.1 through 10.7.5 of this appendix must be used to determine appropriate response plan development and evaluation criteria for facilities that handle, store, or transport animal fats and vegetable oils. Refer to section 11 of this appendix for information on the limitations on the use of chemical agents for inland and nearshore areas.

10.7.1 An owner or operator of a facility that handles, stores, or transports animal fats and vegetable oils must provide information in the response plan that identifies:

(1) Procedures and strategies for responding to a worst case discharge of animal fats and vegetable oils to the maximum extent practicable; and

(2) Sources of the equipment and supplies necessary to locate, recover, and mitigate such a discharge.

10.7.2 An owner or operator of a facility that handles, stores, or transports animal fats and vegetable oils must ensure that any equipment identified in a response plan is capable of operating in the geographic area(s) (*i.e.*, operating environments) in which the facility operates using the criteria in Table 1 of this appendix. When evaluating the operability of equipment, the facility owner or operator must consider limitations that are identified in the appropriate ACPs, including:

(1) Ice conditions;

(2) Debris;

(3) Temperature ranges; and

(4) Weather-related visibility.

10.7.3. The owner or operator of a facility that handles, stores, or transports animal fats and vegetable oils must identify the response resources that are available by contract or other approved means, as described in §112.2. The equipment described in the response plan shall, as appropriate, include:

(1) Containment boom, sorbent boom, or other methods for containing oil floating on the surface or to protect shorelines from impact;

(2) Oil recovery devices appropriate for the type of animal fat or vegetable oil carried; and

(3) Other appropriate equipment necessary to respond to a discharge involving the type of oil carried.

10.7.4 Response resources identified in a response plan according to section 10.7.3 of this appendix must be capable of commencing an effective on-scene response within the applicable tier response times in section 5.3 of this appendix.

10.7.5 A response plan must identify response resources with fire fighting capability. The owner or operator of a facility that handles, stores, or transports animal fats and vegetable oils that does not have adequate fire fighting resources located at the facility or that cannot rely on sufficient local fire fighting resources must identify adequate fire fighting resources. The owner or operator shall ensure, by contract or other approved means as described in §112.2, the availability of these resources. The response plan shall also identify an individual located at the facility to work with the fire department for animal fat and vegetable oil fires. This individual shall also verify that sufficient well-trained fire fighting resources are available within a reasonable response time to respond to a worst case discharge.

The individual may be the qualified individual identified in the response plan or another appropriate individual located at the facility.

11.0 Determining the Availability of Alternative Response Methods

11.1 For chemical agents to be identified in a response plan, they must be on the NCP Product Schedule that is maintained by EPA. (Some States have a list of approved dispersants for use within State waters. Not all of these State-approved dispersants are listed on the NCP Product Schedule.)

11.2 Identification of chemical agents in the plan does not imply that their use will be authorized. Actual authorization will be governed by the provisions of the NCP and the applicable ACP.

12.0 Additional Equipment Necessary to Sustain Response Operations

12.1 A facility owner or operator shall identify sufficient response resources available, by contract or other approved means as described in §112.2, to respond to a medium discharge of animal fats or vegetables oils for that facility. This will require response resources capable of containing and collecting up to 36,000 gallons of oil or 10 percent of the worst case discharge, whichever is less. All equipment identified must be designed to operate in the applicable operating environment specified in Table 1 of this appendix.

12.2 A facility owner or operator shall evaluate the availability of adequate temporary storage capacity to sustain the effective daily recovery capacities from equipment identified in the plan. Because of the inefficiencies of oil spill recovery devices, response plans must identify daily storage capacity equivalent to twice the effective daily recovery capacity required on-scene. This temporary storage capacity may be reduced if a facility owner or operator can demonstrate by waste stream analysis that the efficiencies of the oil recovery devices, ability to decant waste, or the availability of alternative temporary storage or disposal locations will reduce the overall volume of oily material storage.

12.3 A facility owner or operator shall ensure that response planning includes the capability to arrange for disposal of recovered oil products. Specific disposal procedures will be addressed in the applicable ACP.

13.0 References and Availability

13.1 All materials listed in this section are part of EPA's rulemaking docket and are located in the Superfund Docket, 1235 Jefferson Davis Highway, Crystal Gateway 1, Arlington, Virginia 22202, Suite 105 (Docket Numbers SPCC–2P, SPCC–3P, and SPCC–9P). The docket is available for inspection between 9 a.m. and 4 p.m., Monday through Friday, excluding Federal holidays.

Appointments to review the docket can be made by calling 703–603–9232. Docket hours are subject to change. As provided in 40 CFR part 2, a reasonable fee may be charged for copying services.

13.2 The docket will mail copies of materials to requestors who are outside the Washington, DC metropolitan area. Materials may be available from other sources, as noted in this section. As provided in 40 CFR part 2, a reasonable fee may be charged for copying services. The RCRA/Superfund Hotline at 800–424–9346 may also provide additional information on where to obtain documents. To contact the RCRA/Superfund Hotline in the Washington, DC metropolitan area, dial 703–412–9810. The Telecommunications Device for the Deaf (TDD) Hotline number is 800–553–7672, or, in the Washington, DC metropolitan area, 703–412–3323.

13.3 Documents

(1) National Preparedness for Response Exercise Program (PREP). The PREP draft guidelines are available from United States Coast Guard Headquarters (G-MEP-4), 2100 Second Street, SW., Washington, DC 20593. (See 58 FR 53990–91, October 19, 1993, Notice of Availability of PREP Guidelines).

(2) ''Guidance for Facility and Vessel Response Plans: Fish and Wildlife and Sensitive Environments (published in the FEDERAL REGISTER by DOC/NOAA at 59 FR 14713–22, March 29, 1994.). The guidance is available in the Superfund Docket (see sections 13.1 and 13.2 of this appendix).

(3) ASTM Standards. ASTM F 715, ASTM F 989, ASTM F 631–99, ASTM F 808–83 (1999). The ASTM standards are available from the American Society for Testing and Materials, 100 Barr Harbor Drive, West Conshohocken, PA 19428–2959.

(4) Response Plans for Marine Transportation-Related Facilities, Interim Final Rule. Published by USCG, DOT at 58 FR 7330–76, February 5, 1993.

TABLE 1 TO APPENDIX E—RESPONSE RESOURCE OPERATING CRITERIA

Oil Recovery Devices		
Operating environment	Significant wave height [1]	Sea state
Rivers and Canals	≤ 1 foot	1
Inland	≤ 3 feet	2

TABLE 1 TO APPENDIX E—RESPONSE RESOURCE OPERATING CRITERIA—Continued

Oil Recovery Devices		
Operating environment	Significant wave height [1]	Sea state
Great Lakes	≤ 4 feet	2–3
Ocean	≤ 6 feet	3–4

Boom				
Boom property	Use			
	Rivers and canals	Inland	Great Lakes	Ocean
Significant Wave Height [1]	≤ 1	≤ 3	≤ 4	≤ 6
Sea State	1	2	2–3	3–4
Boom height—inches (draft plus freeboard)	6–18	18–42	18–42	≥42
Reserve Buoyancy to Weight Ratio	2:1	2:1	2:1	3:1 to 4:1
Total Tensile Strength—pounds	4,500	15,000–20,000.	15,000–20,000.	≥20,000
Skirt Fabric Tensile Strength—pounds	200	300	300	500
Skirt Fabric Tear Strength—pounds	100	100	100	125

[1] Oil recovery devices and boom *shall* be at least capable of operating in wave heights up to and including the values listed in Table 1 for each operating environment.

TABLE 2 TO APPENDIX E—REMOVAL CAPACITY PLANNING TABLE FOR PETROLEUM OILS

Spill location	Rivers and canals			Nearshore/Inland/Great Lakes		
Sustainability of on-water oil recovery	3 days			4 days		
Oil group [1]	Percent natural dissipation	Percent recovered floating oil	Percent oil onshore	Percent natural dissipation	Percent recovered floating oil	Percent oil onshore
1—Non-persistent oils	80	10	10	80	20	10
2—Light crudes	40	15	45	50	50	30
3—Medium crudes and fuels	20	15	65	30	50	50
4—Heavy crudes and fuels	5	20	75	10	50	70

[1] The response resource considerations for non-petroleum oils other than animal fats and vegetable oils are outlined in section 7.7 of this appendix.

NOTE: Group 5 oils are defined in section 1.2.8 of this appendix; the response resource considerations are outlined in section 7.6 of this appendix.

TABLE 3 TO APPENDIX E—EMULSIFICATION FACTORS FOR PETROLEUM OIL GROUPS [1]

Non-Persistent Oil:	
Group 1	1.0
Persistent Oil:	
Group 2	1.8
Group 3	2.0
Group 4	1.4
Group 5 oils are defined in section 1.2.7 of this appendix; the response resource considerations are outlined in section 7.6 of this appendix.	

[1] See sections 1.2.2 and 1.2.7 of this appendix for group designations for non-persistent and persistent oils, respectively.

TABLE 4 TO APPENDIX E—ON-WATER OIL RECOVERY RESOURCE MOBILIZATION FACTORS

Operating area	Tier 1	Tier 2	Tier 3
Rivers and Canals	0.30	0.40	0.60
Inland/Nearshore Great Lakes	0.15	0.25	0.40

Note: These mobilization factors are for total resources mobilized, not incremental response resources.

TABLE 5 TO APPENDIX E—RESPONSE CAPABILITY CAPS BY OPERATING AREA

	Tier 1	Tier 2	Tier 3
February 18, 1993:			
All except Rivers & Canals, Great Lakes	10K bbls/day	20K bbls/day	40K bbls/day.
Great Lakes	5K bbls/day	10K bbls/day	20K bbls/day.
Rivers & Canals	1.5K bbls/day	3.0K bbls/day	6.0K bbls/day.

TABLE 5 TO APPENDIX E—RESPONSE CAPABILITY CAPS BY OPERATING AREA—Continued

	Tier 1	Tier 2	Tier 3
February 18, 1998:			
All except Rivers & Canals, Great Lakes	12.5K bbls/day	25K bbls/day	50K bbls/day.
Great Lakes	6.35K bbls/day	12.3K bbls/day	25K bbls/day.
Rivers & Canals	1.875K bbls/day	3.75K bbls/day	7.5K bbls/day.
February 18, 2003:			
All except Rivers & Canals, Great Lakes	TBD	TBD	TBD.
Great Lakes	TBD	TBD	TBD.
Rivers & Canals	TBD	TBD	TBD.

Note: The caps show cumulative overall effective daily recovery capacity, not incremental increases.
TBD=To Be Determined.

TABLE 6 TO APPENDIX E—REMOVAL CAPACITY PLANNING TABLE FOR ANIMAL FATS AND VEGETABLE OILS

Spill location	Rivers and canals			Nearshore/Inland/Great Lakes		
Sustainability of on-water oil recovery	3 days			4 days		
Oil group [1]	Percent natural loss	Percent recovered floating oil	Percent recovered oil from onshore	Percent natural loss	Percent recovered floating oil	Percent recovered oil from onshore
Group A	40	15	45	50	20	30
Group B	20	15	65	30	20	50

[1] Substances with a specific gravity greater than 1.0 generally sink below the surface of the water. Response resource considerations are outlined in section 10.6 of this appendix. The owner or operator of the facility is responsible for determining appropriate response resources for Group C oils including locating oil on the bottom or suspended in the water column; containment boom or other appropriate methods for containing oil that may remain floating on the surface; and dredges, pumps, or other equipment to recover animal fats or vegetable oils from the bottom and shoreline.

NOTE: Group C oils are defined in sections 1.2.1 and 1.2.9 of this appendix; the response resource procedures are discussed in section 10.6 of this appendix.

TABLE 7 TO APPENDIX E—EMULSIFICATION FACTORS FOR ANIMAL FATS AND VEGETABLE OILS

Oil Group [1]:	
Group A	1.0
Group B	2.0

[1] Substances with a specific gravity greater than 1.0 generally sink below the surface of the water. Response resource considerations are outlined in section 10.6 of this appendix. The owner or operator of the facility is responsible for determining appropriate response resources for Group C oils including locating oil on the bottom or suspended in the water column; containment boom or other appropriate methods for containing oil that may remain floating on the surface; and dredges, pumps, or other equipment to recover animal fats or vegetable oils from the bottom and shoreline.

NOTE: Group C oils are defined in sections 1.2.1 and 1.2.9 of this appendix; the response resource procedures are discussed in section 10.6 of this appendix.

ATTACHMENTS TO APPENDIX E

Attachment E-1 --
Worksheet to Plan Volume of Response Resources
for Worst Case Discharge - Petroleum Oils

Part I Background Information

Step (A) Calculate Worst Case Discharge in barrels (Appendix D) [ ] (A)

Step (B) Oil Group[1] (Table 3 and section 1.2 of this appendix) . [ ]

Step (C) Operating Area (choose one) . . . . [ ] Near shore/Inland Great Lakes [ ] or Rivers and Canals

Step (D) Percentages of Oil (Table 2 of this appendix)

Percent Lost to Natural Dissipation	Percent Recovered Floating Oil	Percent Oil Onshore
[ ]	[ ]	[ ]
(D1)	(D2)	(D3)

Step (E1) On-Water Oil Recovery $\frac{\text{Step (D2) x Step(A)}}{100}$ [ ] (E1)

Step (E2) Shoreline Recovery $\frac{\text{Step (D3) x Step (A)}}{100}$ . . . . [ ] (E2)

Step (F) Emulsification Factor (Table 3 of this appendix) . . . . . [ ] (F)

Step (G) On-Water Oil Recovery Resource Mobilization Factor (Table 4 of this appendix)

Tier 1	Tier 2	Tier 3
[ ]	[ ]	[ ]
(G1)	(G2)	(G3)

[1] A facility that handles, stores, or transports multiple groups of oil must do separate calculations for each oil group on site except for those oil groups that constitute 10 percent or less by volume of the total oil storage capacity at the facility. For purposes of this calculation, the volumes of all products in an oil group must be summed to determine the percentage of the facility's total oil storage capacity.

Attachment E-1 (continued) --
Worksheet to Plan Volume of Response Resources
for Worst Case Discharge - Petroleum Oils

Part II On-Water Oil Recovery Capacity (barrels/day)

Tier 1	Tier 2	Tier 3
Step (E1) x Step (F) x Step (G1)	Step (E1) x Step (F) x Step (G2)	Step (E1) x Step (F) x Step (G3)

Part III Shoreline Cleanup Volume (barrels) . . . . . .

Step (E2) x Step (F)

Part IV On-Water Response Capacity By Operating Area
(Table 5 of this appendix)
(Amount needed to be contracted for in barrels/day)

Tier 1	Tier 2	Tier 3
(J1)	(J2)	(J3)

Part V On-Water Amount Needed to be Identified, but not Contracted for in Advance (barrels/day)

Tier 1	Tier 2	Tier 3
Part II Tier 1 - Step (J1)	Part II Tier 2 - Step (J2)	Part II Tier 3 - Step (J3)

NOTE: To convert from barrels/day to gallons/day, multiply the quantities in Parts II through V by 42 gallons/barrel.

Attachment E-1 Example --
Worksheet to Plan Volume of Response Resources
for Worst Case Discharge - Petroleum Oils

Part I Background Information

Step (A) Calculate Worst Case Discharge in barrels (Appendix D) [170,000] (A)

Step (B) Oil Group[1] (Table 3 and section 1.2 of this appendix) . [4]

Step (C) Operating Area (choose one) . . [X] Near shore/Inland Great Lakes [ ] or Rivers and Canals

Step (D) Percentages of Oil (Table 2 of this appendix)

Percent Lost to Natural Dissipation	Percent Recovered Floating Oil	Percent Oil Onshore
10	50	70
(D1)	(D2)	(D3)

Step (E1) On-Water Oil Recovery $\frac{\text{Step (D2) x Step (A)}}{100}$ [85,000] (E1)

Step (E2) Shoreline Recovery $\frac{\text{Step (D3) x Step (A)}}{100}$ [119,000] (E2)

Step (F) Emulsification Factor (Table 3 of this appendix) . . . . . [1.4] (F)

Step (G) On-Water Oil Recovery Resource Mobilization Factor (Table 4 of this appendix)

Tier 1	Tier 2	Tier 3
0.15	0.25	0.40
(G1)	(G2)	(G3)

[1] A facility that handles, stores, or transports multiple groups of oil must do separate calculations for each oil group on site except for those oil groups that constitute 10 percent or less by volume of the total oil storage capacity at the facility. For purposes of this calculation, the volumes of all products in an oil group must be summed to determine the percentage of the facility's total oil storage capacity.

Attachment E-1 Example (continued) --
Worksheet to Plan Volume of Response Resources
for Worst Case Discharge - Petroleum Oils

Part II On-Water Oil Recovery Capacity (barrels/day)

Tier 1	Tier 2	Tier 3
17,850	29,750	47,600
Step (E1) x Step (F) x Step (G1)	Step (E1) x Step (F) x Step (G2)	Step (E1) x Step (F) x Step (G3)

Part III Shoreline Cleanup Volume (barrels) 166,600

Step (E2) x Step (F)

Part IV On-Water Response Capacity By Operating Area
(Table 5 of this appendix)
(Amount needed to be contracted for in barrels/day)

Tier 1	Tier 2	Tier 3
10,000	20,000	40,000
(J1)	(J2)	(J3)

Part V On-Water Amount Needed to be Identified, but not Contracted for in Advance (barrels/day)

Tier 1	Tier 2	Tier 3
7,850	9,750	7,600
Part II Tier 1 - Step (J1)	Part II Tier 2 - Step (J2)	Part II Tier 3 - Step (J3)

NOTE: To convert from barrels/day to gallons/day, multiply the quantities in Parts II through V by 42 gallons/barrel.

Attachment E-2 --
Worksheet to Plan Volume of Response Resources
for Worst Case Discharge - Animal Fats and Vegetable Oils

Part I Background Information

Step (A) Calculate Worst Case Discharge in barrels (Appendix D) [ ] (A)

Step (B) Oil Group[1] (Table 7 and section 1.2 of this appendix) . [ ]

Step (C) Operating Area (choose one) . . . . [ ] Near shore/Inland Great Lakes [ ] or Rivers and Canals

Step (D) Percentages of Oil (Table 6 of this appendix)

Percent Lost to Natural Dissipation	Percent Recovered Floating Oil	Percent Oil Onshore
[ ]	[ ]	[ ]
(D1)	(D2)	(D3)

Step (E1) On-Water Oil Recovery $\frac{\text{Step (D2) x Step (A)}}{100}$ [ ] (E1)

Step (E2) Shoreline Recovery $\frac{\text{Step (D3) x Step (A)}}{100}$ . . . [ ] (E2)

Step (F) Emulsification Factor (Table 7 of this appendix) . . . . . [ ] (F)

Step (G) On-Water Oil Recovery Resource Mobilization Factor (Table 4 of this appendix)

Tier 1	Tier 2	Tier 3
[ ]	[ ]	[ ]
(G1)	(G2)	(G3)

[1] A facility that handles, stores, or transports multiple groups of oil must do separate calculations for each oil group on site except for those oil groups that constitute 10 percent or less by volume of the total oil storage capacity at the facility. For purposes of this calculation, the volumes of all products in an oil group must be summed to determine the percentage of the facility's total oil storage capacity.

Attachment E-2 (continued) --
Worksheet to Plan Volume of Response Resources
for Worst Case Discharge - Animal Fats and Vegetable Oils

Part II On-Water Oil Recovery Capacity (barrels/day)

Tier 1	Tier 2	Tier 3
Step (E1) x Step (F) x Step (G1)	Step (E1) x Step (F) x Step (G2)	Step (E1) x Step (F) x Step (G3)

Part III Shoreline Cleanup Volume (barrels) . . . .

Step (E2) x Step (F)

Part IV On-Water Response Capacity By Operating Area
(Table 5 of this appendix)
(Amount needed to be contracted for in barrels/day)

Tier 1	Tier 2	Tier 3
(J1)	(J2)	(J3)

Part V On-Water Amount Needed to be Identified, but not Contracted for in Advance (barrels/day)

Tier 1	Tier 2	Tier 3
Part II Tier 1 - Step (J1)	Part II Tier 2 - Step (J2)	Part II Tier 3 - Step (J3)

NOTE: To convert from barrels/day to gallons/day, multiply the quantities in Parts II through V by 42 gallons/barrel.

Attachment E-2 Example --
Worksheet to Plan Volume of Response Resources
for Worst Case Discharge - Animal Fats and Vegetable Oils

Part I Background Information

Step (A) Calculate Worst Case Discharge in barrels (Appendix D) . . . . . **500,000** (A)

Step (B) Oil Group[1] (Table 7 and section 1.2 of this appendix) . . . . . **B**

Step (C) Operating Area (choose one) [X] Near shore/Inl and Great Lakes [ ] or Rivers and Canals

Step (D) Percentages of Oil (Table 6 of this appendix)

Percent Lost to Natural Dissipation	Percent Recovered Floating Oil	Percent Oil Onshore
30	20	50
(D1)	(D2)	(D3)

Step (E1) On-Water Oil Recovery $\frac{\text{Step (D2) x Step (A)}}{100}$ **100,000** (E1)

Step (E2) Shoreline Recovery $\frac{\text{Step (D3) x Step (A)}}{100}$ **250,000** (E2)

Step (F) Emulsification Factor (Table 7 of this appendix) . . . . . **2.0** (F)

Step (G) On-Water Oil Recovery Resource Mobilization Factor (Table 4 of this appendix)

Tier 1	Tier 2	Tier 3
0.15	0.25	0.40
(G1)	(G2)	(G3)

[1] A facility that handles, stores, or transports multiple groups of oil must do separate calculations for each oil group on site except for those oil groups that constitute 10 percent or less by volume of the total oil storage capacity at the facility. For purposes of this calculation, the volumes of all products in an oil group must be summed to determine the percentage of the facility's total oil storage capacity.

Attachment E-2 Example (continued) --
Worksheet to Plan Volume of Response Resources
for Worst Case Discharge - Animal Fats and Vegetable Oils (continued)

Part II On-Water Oil Recovery Capacity (barrels/day)

Tier 1	Tier 2	Tier 3
30,000	50,000	80,000
Step (E1) x Step (F) x Step (G1)	Step (E1) x Step (F) x Step (G2)	Step (E1) x Step (F) x Step (G3)

Part III Shoreline Cleanup Volume (barrels) 500,000

Step (E2) x Step (F)

Part IV On-Water Response Capacity By Operating Area
(Table 5 of this appendix)
(Amount needed to be contracted for in barrels/day)

Tier 1	Tier 2	Tier 3
12,500	25,000	50,000
(J1)	(J2)	(J3)

Part V On-Water Amount Needed to be Identified, but not Contracted for in Advance (barrels/day)

Tier 1	Tier 2	Tier 3
17,500	25,000	30,000
Part II Tier 1 - Step (J1)	Part II Tier 2 - Step (J2)	Part II Tier 3 - Step (J3)

NOTE: To convert from barrels/day to gallons/day, multiply the quantities in Parts II through V by 42 gallons/barrel.

[59 FR 34111, July 1, 1994; 59 FR 49006, Sept. 26, 1994, as amended at 65 FR 40806, 40807, June 30, 2000; 65 FR 47325, Aug. 2, 2000; 66 FR 34560, June 29, 2001]

APPENDIX F TO PART 112—FACILITY-SPECIFIC RESPONSE PLAN

Table of Contents

1.0 Model Facility-Specific Response Plan
1.1 Emergency Response Action Plan
1.2 Facility Information
1.3 Emergency Response Information
1.3.1 Notification
1.3.2 Response Equipment List
1.3.3 Response Equipment Testing/Deployment
1.3.4 Personnel
1.3.5 Evacuation Plans
1.3.6 Qualified Individual's Duties
1.4 Hazard Evaluation
1.4.1 Hazard Identification
1.4.2 Vulnerability Analysis
1.4.3 Analysis of the Potential for an Oil Spill
1.4.4 Facility Reportable Oil Spill History
1.5 Discharge Scenarios
1.5.1 Small and Medium Discharges
1.5.2 Worst Case Discharge
1.6 Discharge Detection Systems
1.6.1 Discharge Detection By Personnel
1.6.2 Automated Discharge Detection

1.7 Plan Implementation
1.7.1 Response Resources for Small, Medium, and Worst Case Spills
1.7.2 Disposal Plans
1.7.3 Containment and Drainage Planning
1.8 Self-Inspection, Drills/Exercises, and Response Training
1.8.1 Facility Self-Inspection
1.8.1.1 Tank Inspection
1.8.1.2 Response Equipment Inspection
1.8.1.3 Secondary Containment Inspection
1.8.2 Facility Drills/Exercises
1.8.2.1 Qualified Individual Notification Drill Logs
1.8.2.2 Spill Management Team Tabletop Exercise Logs
1.8.3 Response Training
1.8.3.1 Personnel Response Training Logs
1.8.3.2 Discharge Prevention Meeting Logs
1.9 Diagrams
1.10 Security
2.0 Response Plan Cover Sheet
3.0 Acronyms
4.0 References

1.0 Model Facility-Specific Response Plan

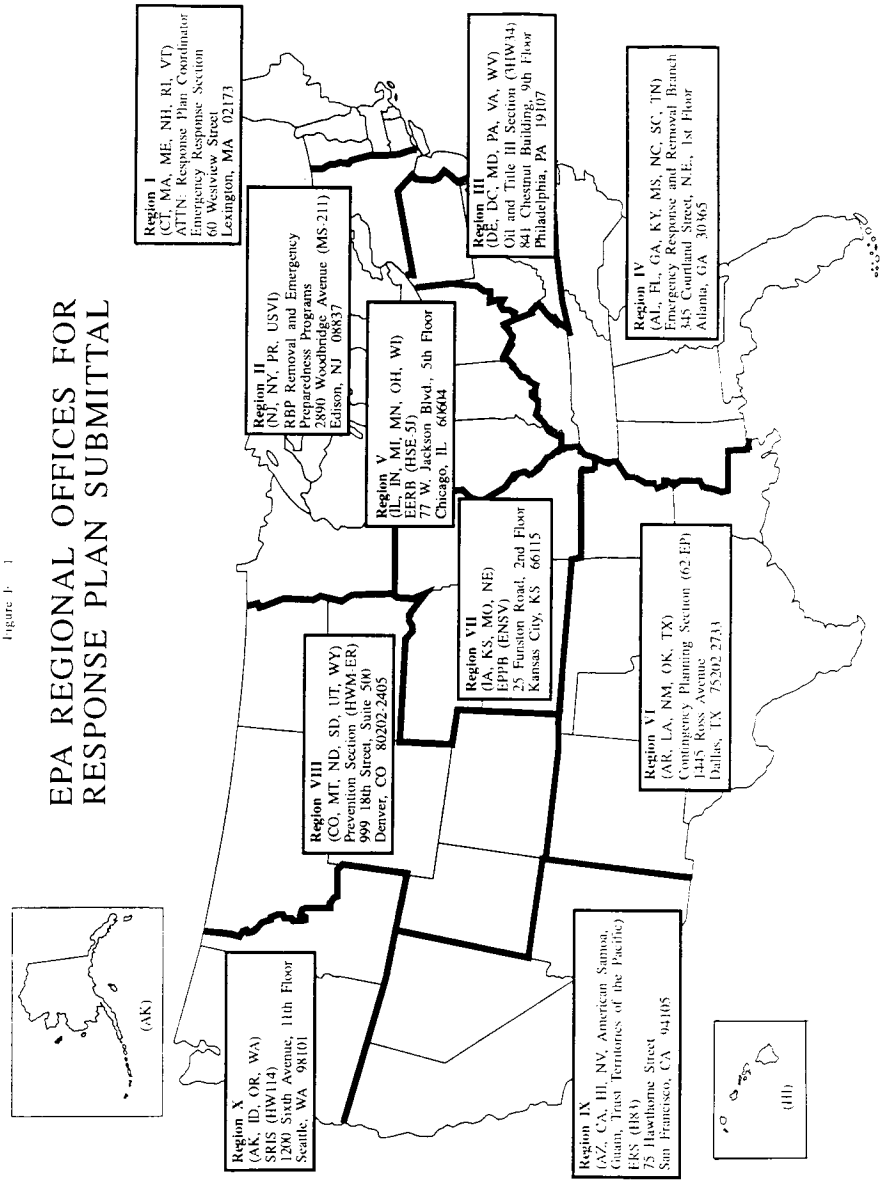
(A) Owners or operators of facilities regulated under this part which pose a threat of substantial harm to the environment by discharging oil into or on navigable waters or adjoining shorelines are required to prepare and submit facility-specific response plans to EPA in accordance with the provisions in this appendix. This appendix further describes the required elements in §112.20(h).

(B) Response plans must be sent to the appropriate EPA Regional office. Figure F–1 of this Appendix lists each EPA Regional office and the address where owners or operators must submit their response plans. Those facilities deemed by the Regional Administrator (RA) to pose a threat of significant and substantial harm to the environment will have their plans reviewed and approved by EPA. In certain cases, information required in the model response plan is similar to information currently maintained in the facility's Spill Prevention, Control, and Countermeasures (SPCC) Plan as required by 40 CFR 112.3. In these cases, owners or operators may reproduce the information and include a photocopy in the response plan.

(C) A complex may develop a single response plan with a set of core elements for all regulating agencies and separate sections for the non-transportation-related and transportation-related components, as described in §112.20(h). Owners or operators of large facilities that handle, store, or transport oil at more than one geographically distinct location (e.g., oil storage areas at opposite ends of a single, continuous parcel of property) shall, as appropriate, develop separate sections of the response plan for each storage area.

Figure F-1

EPA REGIONAL OFFICES FOR RESPONSE PLAN SUBMITTAL



1.1 Emergency Response Action Plan

Several sections of the response plan shall be co-located for easy access by response personnel during an actual emergency or oil discharge. This collection of sections shall be called the Emergency Response Action Plan. The Agency intends that the Action Plan contain only as much information as is necessary to combat the discharge and be arranged so response actions are not delayed. The Action Plan may be arranged in a number of ways. For example, the sections of the Emergency Response Action Plan may be photocopies or condensed versions of the

forms included in the associated sections of the response plan. Each Emergency Response Action Plan section may be tabbed for quick reference. The Action Plan shall be maintained in the front of the same binder that contains the complete response plan or it shall be contained in a separate binder. In the latter case, both binders shall be kept together so that the entire plan can be accessed by the qualified individual and appropriate spill response personnel. The Emergency Response Action Plan shall be made up of the following sections:

1. Qualified Individual Information (Section 1.2) partial
2. Emergency Notification Phone List (Section 1.3.1) partial
3. Spill Response Notification Form (Section 1.3.1) partial
4. Response Equipment List and Location (Section 1.3.2) complete
5. Response Equipment Testing and Deployment (Section 1.3.3) complete
6. Facility Response Team (Section 1.3.4) partial
7. Evacuation Plan (Section 1.3.5) condensed
8. Immediate Actions (Section 1.7.1) complete
9. Facility Diagram (Section 1.9) complete

1.2 Facility Information

The facility information form is designed to provide an overview of the site and a description of past activities at the facility. Much of the information required by this section may be obtained from the facility's existing SPCC Plan.

1.2.1 *Facility name and location:* Enter facility name and street address. Enter the address of corporate headquarters only if corporate headquarters are physically located at the facility. Include city, county, state, zip code, and phone number.

1.2.2 *Latitude and Longitude:* Enter the latitude and longitude of the facility. Include degrees, minutes, and seconds of the main entrance of the facility.

1.2.3 *Wellhead Protection Area:* Indicate if the facility is located in or drains into a wellhead protection area as defined by the Safe Drinking Water Act of 1986 (SDWA).[1] The response plan requirements in the Wellhead Protection Program are outlined by the State or Territory in which the facility resides.

1.2.4 *Owner/operator:* Write the name of the company or person operating the facility and the name of the person or company that owns the facility, if the two are different. List the address of the owner, if the two are different.

1.2.5 *Qualified Individual:* Write the name of the qualified individual for the entire facility. If more than one person is listed, each individual indicated in this section shall have full authority to implement the facility response plan. For each individual, list: name, position, home and work addresses (street addresses, not P.O. boxes), emergency phone number, and specific response training experience.

1.2.6 *Date of Oil Storage Start-up:* Enter the year which the present facility first started storing oil.

1.2.7 *Current Operation:* Briefly describe the facility's operations and include the North American Industrial Classification System (NAICS) code.

1.2.8 *Dates and Type of Substantial Expansion:* Include information on expansions that have occurred at the facility. Examples of such expansions include, but are not limited to: Throughput expansion, addition of a product line, change of a product line, and installation of additional oil storage capacity. The data provided shall include all facility historical information and detail the expansion of the facility. An example of substantial expansion is any material alteration of the facility which causes the owner or operator of the facility to re-evaluate and increase the response equipment necessary to adequately respond to a worst case discharge from the facility.

Date of Last Update: _____

FACILITY INFORMATION FORM

Facility Name: _____
Location (Street Address): _____
City: _____ State: _____ Zip: _____
County: _____ Phone Number: ( ) _____
Latitude: _____ Degrees _____ Minutes _____ Seconds
Longitude: _____ Degrees _____ Minutes _____ Seconds
Wellhead Protection Area: _____
Owner: _____
Owner Location (Street Address): _____
(if different from Facility Address)
City: _____ State:_____ Zip: _____
County: _____ Phone Number: ( ) _____
Operator (if not Owner): _____
Qualified Individual(s): (attach additional sheets if more than one)
Name: _____
Position: _____
Work Address: _____
Home Address: _____
Emergency Phone Number: ( ) _____

[1] A wellhead protection area is defined as the surface and subsurface area surrounding a water well or wellfield, supplying a public water system, through which contaminants are reasonably likely to move toward and reach such water well or wellfield. For further information regarding State and territory protection programs, facility owners or operators may contact the SDWA Hotline at 1–800–426–4791.

Date of Oil Storage Start-up: _____
Current Operations: _____

_____

_____

Date(s) and Type(s) of Substantial Expansion(s): _____

_____

(Attach additional sheets if necessary)

1.3 Emergency Response Information

(A) The information provided in this section shall describe what will be needed in an actual emergency involving the discharge of oil or a combination of hazardous substances and oil discharge. The Emergency Response Information section of the plan must include the following components:

(1) The information provided in the Emergency Notification Phone List in section 1.3.1 identifies and prioritizes the names and phone numbers of the organizations and personnel that need to be notified immediately in the event of an emergency. This section shall include all the appropriate phone numbers for the facility. These numbers must be verified each time the plan is updated. The contact list must be accessible to all facility employees to ensure that, in case of a discharge, any employee on site could immediately notify the appropriate parties.

(2) The Spill Response Notification Form in section 1.3.1 creates a checklist of information that shall be provided to the National Response Center (NRC) and other response personnel. All information on this checklist must be known at the time of notification, or be in the process of being collected. This notification form is based on a similar form used by the NRC. Note: Do not delay spill notification to collect the information on the list.

(3) Section 1.3.2 provides a description of the facility's list of emergency response equipment and location of the response equipment. When appropriate, the amount of oil that emergency response equipment can handle and any limitations (e.g., launching sites) must be described.

(4) Section 1.3.3 provides information regarding response equipment tests and deployment drills. Response equipment deployment exercises shall be conducted to ensure that response equipment is operational and the personnel who would operate the equipment in a spill response are capable of deploying and operating it. Only a representative sample of each type of response equipment needs to be deployed and operated, as long as the remainder is properly maintained. If appropriate, testing of response equipment may be conducted while it is being deployed. Facilities without facility-owned response equipment must ensure that the oil spill removal organization that is identified in the response plan to provide this response equipment certifies that the deployment exercises have been met. Refer to the National Preparedness for Response Exercise Program (PREP) Guidelines (see appendix E to this part, section 13, for availability), which satisfy Oil Pollution Act (OPA) response exercise requirements.

(5) Section 1.3.4 lists the facility response personnel, including those employed by the facility and those under contract to the facility for response activities, the amount of time needed for personnel to respond, their responsibility in the case of an emergency, and their level of response training. Three different forms are included in this section. The Emergency Response Personnel List shall be composed of all personnel employed by the facility whose duties involve responding to emergencies, including oil discharges, even when they are not physically present at the site. An example of this type of person would be the Building Engineer-in-Charge or Plant Fire Chief. The second form is a list of the Emergency Response Contractors (both primary and secondary) retained by the facility. Any changes in contractor status must be reflected in updates to the response plan. Evidence of contracts with response contractors shall be included in this section so that the availability of resources can be verified. The last form is the Facility Response Team List, which shall be composed of both emergency response personnel (referenced by job title/position) and emergency response contractors, included in one of the two lists described above, that will respond immediately upon discovery of an oil discharge or other emergency (i.e., the first people to respond). These are to be persons normally on the facility premises or primary response contractors. Examples of these personnel would be the Facility Hazardous Materials (HAZMAT) Spill Team 1, Facility Fire Engine Company 1, Production Supervisor, or Transfer Supervisor. Company personnel must be able to respond immediately and adequately if contractor support is not available.

(6) Section 1.3.5 lists factors that must, as appropriate, be considered when preparing an evacuation plan.

(7) Section 1.3.6 references the responsibilities of the qualified individual for the facility in the event of an emergency.

(B) The information provided in the emergency response section will aid in the assessment of the facility's ability to respond to a worst case discharge and will identify additional assistance that may be needed. In addition, the facility owner or operator may want to produce a wallet-size card containing a checklist of the immediate response and notification steps to be taken in the event of an oil discharge.

1.3.1 Notification

Date of Last Update: _____

EMERGENCY NOTIFICATION PHONE LIST WHOM TO NOTIFY

Reporter's Name: _____
Date: _____
Facility Name: _____
Owner Name: _____
Facility Identification Number: _____
Date and Time of Each NRC Notification: _____

Organization	Phone No.
1. National Response Center (NRC):	1–800–424–8802
2. Qualified Individual:	
Evening Phone:	
3. Company Response Team:	
Evening Phone:	
4. Federal On-Scene Coordinator (OSC) and/or Regional Response Center (RRC):	
Evening Phone(s):	
Pager Number(s):	
5. Local Response Team (Fire Dept./Co-operatives):	
6. Fire Marshall:	
Evening Phone:	
7. State Emergency Response Commission (SERC):	
Evening Phone:	
8. State Police:	
9. Local Emergency Planning Committee (LEPC):	
10. Local Water Supply System:	
Evening Phone:	
11. Weather Report:	
12. Local Television/Radio Station for Evacuation Notification:	
13. Hospitals:	

SPILL RESPONSE NOTIFICATION FORM

Reporter's Last Name: _____
First: _____
M.I.: _____
Position: _____
Phone Numbers:
Day ( ) –
Evening ( ) –
Company: _____
Organization Type: _____
Address: _____
_____
City: _____
State: _____
Zip: _____
Were Materials Discharged? _____ (Y/N) Confidential? _____ (Y/N)
Meeting Federal Obligations to Report? _____ (Y/N) Date Called: _____
Calling for Responsible Party? _____ (Y/N) Time Called: _____

Incident Description

Source and/or Cause of Incident: _____
_____
_____
_____
_____
Date of Incident: _____
Time of Incident: _____ AM/PM
Incident Address/Location: _____
_____
Nearest City: _____ State: _____ County: _____ Zip: _____
Distance from City: _____ Units of Measure: _____ Direction from City: _____
Section: _____ Township: _____ Range: _____ Borough: _____
Container Type: _____ Tank Oil Storage Capacity: _____ Units of Measure: _____
Facility Oil Storage Capacity: _____ Units of Measure: _____
Facility Latitude: _____ Degrees _____ Minutes _____ Seconds
Facility Longitude: _____ Degrees _____ Minutes _____ Seconds

Material

CHRIS Code	Discharged quantity	Unit of measure	Material Discharged in water	Quantity	Unit of measure

Response Action

Actions Taken to Correct, Control or Mitigate Incident:

_____

_____

_____

_____

Impact

Number of Injuries: _____ Number of Deaths: _____

Were there Evacuations? _____ (Y/N) Number Evacuated: _____

Was there any Damage? _____ (Y/N)

Damage in Dollars (approximate): _____

Medium Affected: _____

Description: _____

More Information about Medium: _____

_____

_____

Additional Information

Any information about the incident not recorded elsewhere in the report:

_____

_____

_____

Caller Notifications

EPA? _____ (Y/N) USCG? _____ (Y/N) State? _____ (Y/N)

Other? _____ (Y/N) Describe: _____

1.3.2 Response Equipment List

Date of Last Update:_____

FACILITY RESPONSE EQUIPMENT LIST

1. Skimmers/Pumps—Operational Status: __

Type, Model, and Year: _____

_____

Type Model Year

Number: _____

Capacity: _____ gal./min.

Daily Effective Recovery Rate: _____

Storage Location(s): _____

Date Fuel Last Changed: _____

2. Boom—Operational Status: _____

Type, Model, and Year: _____

Type Model Year

Number: _____

Size (length): _____ ft.

Containment Area: _____ sq. ft.

Storage Location: _____

3. Chemicals Stored (Dispersants listed on EPA's NCP Product Schedule)

Type	Amount	Date purchased	Treatment capacity	Storage location

Were appropriate procedures used to receive approval for use of dispersants in accordance with the NCP (40 CFR 300.910) and the Area Contingency Plan (ACP), where applicable?_____ (Y/N).

Name and State of On-Scene Coordinator (OSC) authorizing use: _____ .

Date Authorized: _____ .

4. Dispersant Dispensing Equipment—Operational Status: _____ .

Type and year	Capacity	Storage location	Response time (minutes)

5. Sorbents—Operational Status: _____

Type and Year Purchased: _____

Amount: _____

Absorption Capacity (gal.): _____

Storage Location(s): _____

6. Hand Tools—Operational Status: _____

Type and year	Quantity	Storage location

Type and year	Quantity	Storage location

7. Communication Equipment (include operating frequency and channel and/or cellular phone numbers)—Operational Status: _____

Type and year	Quantity	Storage location/ number

8. Fire Fighting and Personnel Protective Equipment—Operational Status: _____

Type and year	Quantity	Storage location

9. Other (e.g., Heavy Equipment, Boats and Motors)—Operational Status: _____

Type and year	Quantity	Storage location

1.3.3 Response Equipment Testing/Deployment

Date of Last Update:_____

Response Equipment Testing and Deployment Drill Log

Last Inspection or Response Equipment Test Date: _____
Inspection Frequency: _____
Last Deployment Drill Date: _____
Deployment Frequency: _____
Oil Spill Removal Organization Certification (if applicable): _____

1.3.4 Personnel

Date of Last Update:_____

EMERGENCY RESPONSE PERSONNEL

Company Personnel

Name	Phone [1]	Response time	Responsibility during response action	Response training type/date
1.				
2.				
3.				
4.				
5.				
6.				
7.				
8.				
9.				
10.				
11.				
12.				

[1] Phone number to be used when person is not on-site.

EMERGENCY RESPONSE CONTRACTORS

Date of Last Update: _____

Contractor	Phone	Response time	Contract responsibility [1]
1.			

EMERGENCY RESPONSE CONTRACTORS—Continued

Date of Last Update: _____

Contractor	Phone	Response time	Contract responsibility [1]
2.			
3.			
4.			

[1] Include evidence of contracts/agreements with response contractors to ensure the availability of personnel and response equipment.

FACILITY RESPONSE TEAM

Date of Last Update:_____

Team member	Response time (minutes)	Phone or pager number (day/evening)
Qualified Individual:		/
		/
		/
		/
		/
		/
		/
		/
		/
		/
		/
		/
		/
		/
		/
		/
		/

NOTE: If the facility uses contracted help in an emergency response situation, the owner or operator must provide the contractors' names and review the contractors' capacities to provide adequate personnel and response equipment.

1.3.5 Evacuation Plans

1.3.5.1 Based on the analysis of the facility, as discussed elsewhere in the plan, a facility-wide evacuation plan shall be developed. In addition, plans to evacuate parts of the facility that are at a high risk of exposure in the event of a discharge or other release must be developed. Evacuation routes must be shown on a diagram of the facility (see section 1.9 of this appendix). When developing evacuation plans, consideration must be given to the following factors, as appropriate:

(1) Location of stored materials;

(2) Hazard imposed by discharged material;

(3) Discharge flow direction;

(4) Prevailing wind direction and speed;

(5) Water currents, tides, or wave conditions (if applicable);

(6) Arrival route of emergency response personnel and response equipment;

(7) Evacuation routes;

(8) Alternative routes of evacuation;

(9) Transportation of injured personnel to nearest emergency medical facility;

(10) Location of alarm/notification systems;

(11) The need for a centralized check-in area for evacuation validation (roll call);

(12) Selection of a mitigation command center; and

(13) Location of shelter at the facility as an alternative to evacuation.

1.3.5.2 One resource that may be helpful to owners or operators in preparing this section of the response plan is The *Handbook of Chemical Hazard Analysis Procedures* by the Federal Emergency Management Agency (FEMA), Department of Transportation (DOT), and EPA. *The Handbook of Chemical Hazard Analysis Procedures* is available from: FEMA , Publication Office, 500 C. Street, S.W., Washington, DC 20472, (202) 646–3484.

1.3.5.3 As specified in §112.20(h)(1)(vi), the facility owner or operator must reference existing community evacuation plans, as appropriate.

1.3.6 Qualified Individual's Duties

The duties of the designated qualified individual are specified in §112.20(h)(3)(ix). The qualified individual's duties must be described and be consistent with the minimum requirements in §112.20(h)(3)(ix). In addition, the qualified individual must be identified with the Facility Information in section 1.2 of the response plan.

1.4 Hazard Evaluation

This section requires the facility owner or operator to examine the facility's operations closely and to predict where discharges could occur. Hazard evaluation is a widely used industry practice that allows facility owners or operators to develop a complete understanding of potential hazards and the response actions necessary to address these hazards. *The Handbook of Chemical Hazard Analysis Procedures*, prepared by the EPA, DOT, and the FEMA and the *Hazardous Materials Emergency Planning Guide* (NRT–1), prepared by the National Response Team are good references for conducting a hazard analysis. Hazard identification and evaluation will assist facility owners or operators in planning for potential discharges, thereby reducing the severity of discharge impacts that may occur in the future. The evaluation also may help the operator identify and correct potential sources of discharges. In addition, special hazards to workers and emergency response personnel's health and safety shall be evaluated, as well as the facility's oil spill history.

1.4.1 Hazard Identification

The Tank and Surface Impoundment (SI) forms, or their equivalent, that are part of this section must be completed according to the directions below. (''Surface Impoundment'' means a facility or part of a facility which is a natural topographic depression, man-made excavation, or diked area formed primarily of earthen materials (although it may be lined with man-made materials), which is designed to hold an accumulation of liquid wastes or wastes containing free liquids, and which is not an injection well or a seepage facility.) Similar worksheets, or their equivalent, must be developed for any other type of storage containers.

(1) List each tank at the facility with a separate and distinct identifier. Begin aboveground tank identifiers with an ''A'' and belowground tank identifiers with a ''B'', or submit multiple sheets with the aboveground tanks and belowground tanks on separate sheets.

(2) Use gallons for the maximum capacity of a tank; and use square feet for the area.

(3) Using the appropriate identifiers and the following instructions, fill in the appropriate forms:

(a) Tank or SI number—Using the aforementioned identifiers (A or B) or multiple reporting sheets, identify each tank or SI at the facility that stores oil or hazardous materials.

(b) Substance Stored—For each tank or SI identified, record the material that is stored therein. If the tank or SI is used to store more than one material, list all of the stored materials.

(c) Quantity Stored—For each material stored in each tank or SI, report the average volume of material stored on any given day.

(d) Tank Type or Surface Area/Year—For each tank, report the type of tank (e.g., floating top), and the year the tank was originally installed. If the tank has been refabricated, the year that the latest refabrication was completed must be recorded in parentheses next to the year installed. For

each SI, record the surface area of the impoundment and the year it went into service.

(e) Maximum Capacity—Record the operational maximum capacity for each tank and SI. If the maximum capacity varies with the season, record the upper and lower limits.

(f) Failure/Cause—Record the cause and date of any tank or SI failure which has resulted in a loss of tank or SI contents.

(4) Using the numbers from the tank and SI forms, label a schematic drawing of the facility. This drawing shall be identical to any schematic drawings included in the SPCC Plan.

(5) Using knowledge of the facility and its operations, describe the following in writing:

(a) The loading and unloading of transportation vehicles that risk the discharge of oil or release of hazardous substances during transport processes. These operations may include loading and unloading of trucks, railroad cars, or vessels. Estimate the volume of material involved in transfer operations, if the exact volume cannot be determined.

(b) Day-to-day operations that may present a risk of discharging oil or releasing a hazardous substance. These activities include scheduled venting, piping repair or replacement, valve maintenance, transfer of tank contents from one tank to another, etc. (not including transportation-related activities). Estimate the volume of material involved in these operations, if the exact volume cannot be determined.

(c) The secondary containment volume associated with each tank and/or transfer point at the facility. The numbering scheme developed on the tables, or an equivalent system, must be used to identify each containment area. Capacities must be listed for each individual unit (tanks, slumps, drainage traps, and ponds), as well as the facility total.

(d) Normal daily throughput for the facility and any effect on potential discharge volumes that a negative or positive change in that throughput may cause.

HAZARD IDENTIFICATION TANKS [1]

Date of Last Update: _____

Tank No.	Substance Stored (Oil and Hazardous Substance)	Quantity Stored (gallons)	Tank Type/Year	Maximum Capacity (gallons)	Failure/Cause

[1] Tank = any container that stores oil.
Attach as many sheets as necessary.

HAZARD IDENTIFICATION SURFACE IMPOUNDMENTS (SIS)

Date of Last Update: _____

SI No.	Substance Stored	Quantity Stored (gallons)	Surface Area/Year	Maximum Capacity (gallons)	Failure/Cause

HAZARD IDENTIFICATION SURFACE IMPOUNDMENTS (SIs)—Continued

Date of Last Update: _____

SI No.	Substance Stored	Quantity Stored (gallons)	Surface Area/Year	Maximum Capacity (gallons)	Failure/Cause

Attach as many sheets as necessary.

1.4.2 Vulnerability Analysis

The vulnerability analysis shall address the potential effects (i.e., to human health, property, or the environment) of an oil discharge. Attachment C–III to Appendix C to this part provides a method that owners or operators shall use to determine appropriate distances from the facility to fish and wildlife and sensitive environments. Owners or operators can use a comparable formula that is considered acceptable by the RA. If a comparable formula is used, documentation of the reliability and analytical soundness of the formula must be attached to the response plan cover sheet. This analysis must be prepared for each facility and, as appropriate, must discuss the vulnerability of:

(1) Water intakes (drinking, cooling, or other);

(2) Schools;

(3) Medical facilities;

(4) Residential areas;

(5) Businesses;

(6) Wetlands or other sensitive environments;[2]

(7) Fish and wildlife;

(8) Lakes and streams;

(9) Endangered flora and fauna;

(10) Recreational areas;

(11) Transportation routes (air, land, and water);

(12) Utilities; and

(13) Other areas of economic importance (e.g., beaches, marinas) including terrestrially sensitive environments, aquatic environments, and unique habitats.

1.4.3 Analysis of the Potential for an Oil Discharge

Each owner or operator shall analyze the probability of a discharge occurring at the facility. This analysis shall incorporate factors such as oil discharge history, horizontal range of a potential discharge, and vulnerability to natural disaster, and shall, as appropriate, incorporate other factors such as tank age. This analysis will provide information for developing discharge scenarios for a worst case discharge and small and medium discharges and aid in the development of techniques to reduce the size and frequency of discharges. The owner or operator may need to research the age of the tanks the oil discharge history at the facility.

1.4.4 Facility Reportable Oil Spill History

Briefly describe the facility's reportable oil spill[3] history for the entire life of the facility to the extent that such information is reasonably identifiable, including:

(1) Date of discharge(s);

(2) List of discharge causes;

(3) Material(s) discharged;

(4) Amount discharged in gallons;

(5) Amount of discharge that reached navigable waters, if applicable;

(6) Effectiveness and capacity of secondary containment;

(7) Clean-up actions taken;

(8) Steps taken to reduce possibility of recurrence;

(9) Total oil storage capacity of the tank(s) or impoundment(s) from which the material discharged;

(10) Enforcement actions;

(11) Effectiveness of monitoring equipment; and

(12) Description(s) of how each oil discharge was detected.

[2] Refer to the DOC/NOAA ''Guidance for Facility and Vessel Response Plans: Fish and Wildlife and Sensitive Environments'' (See appendix E to this part, section 13, for availability).

[3] As described in 40 CFR part 110, reportable oil spills are those that: (a) violate applicable water quality standards, or (b) cause a film or sheen upon or discoloration of the surface of the water or adjoining shorelines or cause a sludge or emulsion to be deposited beneath the surface of the water or upon adjoining shorelines.

The information solicited in this section may be similar to requirements in 40 CFR 112.4(a). Any duplicate information required by §112.4(a) may be photocopied and inserted.

1.5 Discharge Scenarios

In this section, the owner or operator is required to provide a description of the facility's worst case discharge, as well as a small and medium discharge, as appropriate. A multi-level planning approach has been chosen because the response actions to a discharge (*i.e.*, necessary response equipment, products, and personnel) are dependent on the magnitude of the discharge. Planning for lesser discharges is necessary because the nature of the response may be qualitatively different depending on the quantity of the discharge. The facility owner or operator shall discuss the potential direction of the discharge pathway.

1.5.1 Small and Medium Discharges

1.5.1.1 To address multi-level planning requirements, the owner or operator must consider types of facility-specific discharge scenarios that may contribute to a small or medium discharge. The scenarios shall account for all the operations that take place at the facility, including but not limited to:

(1) Loading and unloading of surface transportation;

(2) Facility maintenance;

(3) Facility piping;

(4) Pumping stations and sumps;

(5) Oil storage tanks;

(6) Vehicle refueling; and

(7) Age and condition of facility and components.

1.5.1.2 The scenarios shall also consider factors that affect the response efforts required by the facility. These include but are not limited to:

(1) Size of the discharge;

(2) Proximity to downgradient wells, waterways, and drinking water intakes;

(3) Proximity to fish and wildlife and sensitive environments;

(4) Likelihood that the discharge will travel offsite (*i.e.*, topography, drainage);

(5) Location of the material discharged (*i.e.*, on a concrete pad or directly on the soil);

(6) Material discharged;

(7) Weather or aquatic conditions (*i.e.*, river flow);

(8) Available remediation equipment;

(9) Probability of a chain reaction of failures; and

(10) Direction of discharge pathway.

1.5.2 Worst Case Discharge

1.5.2.1 In this section, the owner or operator must identify the worst case discharge volume at the facility. Worksheets for production and non-production facility owners or operators to use when calculating worst case discharge are presented in appendix D to this part. When planning for the worst case discharge response, all of the aforementioned factors listed in the small and medium discharge section of the response plan shall be addressed.

1.5.2.2 For onshore storage facilities and production facilities, permanently manifolded oil storage tanks are defined as tanks that are designed, installed, and/or operated in such a manner that the multiple tanks function as one storage unit (i.e., multiple tank volumes are equalized). In this section of the response plan, owners or operators must provide evidence that oil storage tanks with common piping or piping systems are not operated as one unit. If such evidence is provided and is acceptable to the RA, the worst case discharge volume shall be based on the combined oil storage capacity of all manifold tanks or the oil storage capacity of the largest single oil storage tank within the secondary containment area, whichever is greater. For permanently manifolded oil storage tanks that function as one storage unit, the worst case discharge shall be based on the combined oil storage capacity of all manifolded tanks or the oil storage capacity of the largest single tank within a secondary containment area, whichever is greater. For purposes of the worst case discharge calculation, permanently manifolded oil storage tanks that are separated by internal divisions for each tank are considered to be single tanks and individual manifolded tank volumes are not combined.

1.6 Discharge Detection Systems

In this section, the facility owner or operator shall provide a detailed description of the procedures and equipment used to detect discharges. A section on discharge detection by personnel and a discussion of automated discharge detection, if applicable, shall be included for both regular operations and after hours operations. In addition, the facility owner or operator shall discuss how the reliability of any automated system will be checked and how frequently the system will be inspected.

1.6.1 Discharge Detection by Personnel

In this section, facility owners or operators shall describe the procedures and personnel that will detect any discharge of oil or release of a hazardous substance. A thorough discussion of facility inspections must be included. In addition, a description of initial response actions shall be addressed. This section shall reference section 1.3.1 of the response plan for emergency response information.

1.6.2 Automated Discharge Detection

In this section, facility owners or operators must describe any automated discharge detection equipment that the facility has in place. This section shall include a discussion of overfill alarms, secondary containment sensors, etc. A discussion of the plans to verify an automated alarm and the actions to be taken once verified must also be included.

1.7 Plan Implementation

In this section, facility owners or operators must explain in detail how to implement the facility's emergency response plan by describing response actions to be carried out under the plan to ensure the safety of the facility and to mitigate or prevent discharges described in section 1.5 of the response plan. This section shall include the identification of response resources for small, medium, and worst case discharges; disposal plans; and containment and drainage planning. A list of those personnel who would be involved in the cleanup shall be identified. Procedures that the facility will use, where appropriate or necessary, to update their plan after an oil discharge event and the time frame to update the plan must be described.

1.7.1 Response Resources for Small, Medium, and Worst Case Discharages

1.7.1.1 Once the discharge scenarios have been identified in section 1.5 of the response plan, the facility owner or operator shall identify and describe implementation of the response actions. The facility owner or operator shall demonstrate accessibility to the proper response personnel and equipment to effectively respond to all of the identified discharge scenarios. The determination and demonstration of adequate response capability are presented in appendix E to this part. In addition, steps to expedite the cleanup of oil discharges must be discussed. At a minimum, the following items must be addressed:

(1) Emergency plans for spill response;

(2) Additional response training;

(3) Additional contracted help;

(4) Access to additional response equipment/experts; and

(5) Ability to implement the plan including response training and practice drills.

1.7.1.2A recommended form detailing immediate actions follows.

OIL SPILL RESPONSE—IMMEDIATE ACTIONS

1. Stop the product flow	Act quickly to secure pumps, close valves, etc.
2. Warn personnel	Enforce safety and security measures.
3. Shut off ignition sources.	Motors, electrical circuits, open flames, etc.
4. Initiate containment	Around the tank and/or in the water with oil boom.
5. Notify NRC	1–800–424–8802
6. Notify OSC	
7. Notify, as appropriate	

Source: FOSS, Oil Spill Response—Emergency Procedures, Revised December 3, 1992.

1.7.2 Disposal Plans

1.7.2.1 Facility owners or operators must describe how and where the facility intends to recover, reuse, decontaminate, or dispose of materials after a discharge has taken place. The appropriate permits required to transport or dispose of recovered materials according to local, State, and Federal requirements must be addressed. Materials that must be accounted for in the disposal plan, as appropriate, include:

(1) Recovered product;

(2) Contaminated soil;

(3) Contaminated equipment and materials, including drums, tank parts, valves, and shovels;

(4) Personnel protective equipment;

(5) Decontamination solutions;

(6) Adsorbents; and

(7) Spent chemicals.

1.7.2.2 These plans must be prepared in accordance with Federal (e.g., the Resource Conservation and Recovery Act [RCRA]), State, and local regulations, where applicable. A copy of the disposal plans from the facility's SPCC Plan may be inserted with this section, including any diagrams in those plans.

Material	Disposal facility	Location	RCRA permit/manifest
1.			
2.			
3.			
4.			

1.7.3 Containment and Drainage Planning

A proper plan to contain and control a discharge through drainage may limit the threat of harm to human health and the environment. This section shall describe how to contain and control a discharge through drainage, including:

(1) The available volume of containment (use the information presented in section 1.4.1 of the response plan);

(2) The route of drainage from oil storage and transfer areas;

(3) The construction materials used in drainage troughs;

(4) The type and number of valves and separators used in the drainage system;

(5) Sump pump capacities;

(6) The containment capacity of weirs and booms that might be used and their location (see section 1.3.2 of this appendix); and

(7) Other cleanup materials.

In addition, a facility owner or operator must meet the inspection and monitoring requirements for drainage contained in 40 CFR part 112, subparts A through C. A copy of the containment and drainage plans that are required in 40 CFR part 112, subparts A through C may be inserted in this section, including any diagrams in those plans.

NOTE: The general permit for stormwater drainage may contain additional requirements.

1.8 Self-Inspection, Drills/Exercises, and Response Training

The owner or operator must develop programs for facility response training and for drills/exercises according to the requirements of 40 CFR 112.21. Logs must be kept for facility drills/exercises, personnel response training, and spill prevention meetings. Much of the recordkeeping information required by this section is also contained in the SPCC Plan required by 40 CFR 112.3. These logs may be included in the facility response plan or kept as an annex to the facility response plan.

1.8.1 Facility Self-Inspection

Under 40 CFR 112.7(e), you must include the written procedures and records of inspections for each facility in the SPCC Plan. You must include the inspection records for each container, secondary containment, and item of response equipment at the facility. You must cross-reference the records of inspections of each container and secondary containment required by 40 CFR 112.7(e) in the facility response plan. The inspection record of response equipment is a new requirement in this plan. Facility self-inspection requires two-steps: (1) a checklist of things to inspect; and (2) a method of recording the actual inspection and its findings. You must note the date of each inspection. You must keep facility response plan records for five years. You must keep SPCC records for three years.

1.8.1.1. Tank Inspection

The tank inspection checklist presented below has been included as guidance during inspections and monitoring. Similar requirements exist in 40 CFR part 112, subparts A through C. Duplicate information from the SPCC Plan may be photocopied and inserted in this section. The inspection checklist consists of the following items:

TANK INSPECTION CHECKLIST

1. Check tanks for leaks, specifically looking for:
   A. drip marks;
   B. discoloration of tanks;
   C. puddles containing spilled or leaked material;
   D. corrosion;
   E. cracks; and
   F. localized dead vegetation.
2. Check foundation for:
   A. cracks;
   B. discoloration;
   C. puddles containing spilled or leaked material;
   D. settling;
   E. gaps between tank and foundation; and
   F. damage caused by vegetation roots.
3. Check piping for:
   A. droplets of stored material;
   B. discoloration;
   C. corrosion;
   D. bowing of pipe between supports;
   E. evidence of stored material seepage from valves or seals; and
   F. localized dead vegetation.

TANK/SURFACE IMPOUNDMENT INSPECTION LOG

Inspector	Tank or SI#	Date	Comments

TANK/SURFACE IMPOUNDMENT INSPECTION LOG—Continued

Inspector	Tank or SI#	Date	Comments

1.8.1.2 Response Equipment Inspection

Using the Emergency Response Equipment List provided in section 1.3.2 of the response plan, describe each type of response equipment, checking for the following:

Response Equipment Checklist

1. Inventory (item and quantity);
2. Storage location;
3. Accessibility (time to access and respond);
4. Operational status/condition;
5. Actual use/testing (last test date and frequency of testing); and
6. Shelf life (present age, expected replacement date).

Please note any discrepancies between this list and the available response equipment.

RESPONSE EQUIPMENT INSPECTION LOG

[Use section 1.3.2 of the response plan as a checklist]

Inspector	Date	Comments

RESPONSE EQUIPMENT INSPECTION LOG—Continued

[Use section 1.3.2 of the response plan as a checklist]

Inspector	Date	Comments

1.8.1.3 Secondary Containment Inspection

Inspect the secondary containment (as described in sections 1.4.1 and 1.7.2 of the response plan), checking the following:

Secondary Containment Checklist

1. Dike or berm system.
   A. Level of precipitation in dike/available capacity;
   B. Operational status of drainage valves;
   C. Dike or berm permeability;
   D. Debris;
   E. Erosion;
   F. Permeability of the earthen floor of diked area; and
   G. Location/status of pipes, inlets, drainage beneath tanks, etc.
2. Secondary containment
   A. Cracks;
   B. Discoloration;
   C. Presence of spilled or leaked material (standing liquid);
   D. Corrosion; and
   E. Valve conditions.
3. Retention and drainage ponds
   A. Erosion;
   B. Available capacity;
   C. Presence of spilled or leaked material;
   D. Debris; and
   E. Stressed vegetation.

The tank inspection checklist presented below has been included as guidance during inspections and monitoring. Similar requirements exist in 40 CFR part 112, subparts A through C. Similar requirements exist in 40 CFR 112.7(e). Duplicate information from the SPCC Plan may be photocopied and inserted in this section.

1.8.2 Facility Drills/Exercises

(A) CWA section 311(j)(5), as amended by OPA, requires the response plan to contain a description of facility drills/exercises. According to 40 CFR 112.21(c), the facility owner or operator shall develop a program of facility response drills/exercises, including evaluation procedures. Following the PREP guidelines (see appendix E to this part, section 13, for availability) would satisfy a facility's requirements for drills/exercises under this part. Alternately, under §112.21(c), a facility owner or operator may develop a program that is not based on the PREP guidelines. Such a program is subject to approval by the Regional Administrator based on the description of the program provided in the response plan.

(B) The PREP Guidelines specify that the facility conduct internal and external drills/exercises. The internal exercises include: qualified individual notification drills, spill management team tabletop exercises, equipment deployment exercises, and unannounced exercises. External exercises include Area Exercises. Credit for an Area or Facility-specific Exercise will be given to the facility for an actual response to a discharge in the area if the plan was utilized for response to the discharge and the objectives of the Exercise were met and were properly evaluated, documented, and self-certified.

(C) Section 112.20(h)(8)(ii) requires the facility owner or operator to provide a description of the drill/exercise program to be carried out under the response plan. Qualified Individual Notification Drill and Spill Management Team Tabletop Drill logs shall be provided in sections 1.8.2.1 and 1.8.2.2, respectively. These logs may be included in the facility response plan or kept as an annex to the facility response plan. See section 1.3.3 of this appendix for Equipment Deployment Drill Logs.

1.8.2.1 Qualified Individual Notification Drill Logs

Qualified Individual Notification Drill Log

Date: _____
Company: _____
Qualified Individual(s): _____
Emergency Scenario: _____

Evaluation: _____

Changes to be Implemented: _____

Time Table for Implementation: _____

1.8.2.2 Spill Management Team Tabletop Exercise Logs

Spill Management Team Tabletop Exercise Log

Date: _____
Company: _____
Qualified Individual(s): _____
Emergency Scenario: _____

Evaluation: _____

Changes to be Implemented: _____

Time Table for Implementation: _____

1.8.3 Response Training

Section 112.21(a) requires facility owners or operators to develop programs for facility response training. Facility owners or operators are required by §112.20(h)(8)(iii) to provide a description of the response training program to be carried out under the response plan. A facility's training program can be based on the USCG's Training Elements for Oil Spill Response, to the extent applicable to facility operations, or another response training program acceptable to the RA. The training elements are available from the USCG Office of Response (G-MOR) at (202) 267–0518 or fax (202) 267–4085. Personnel response training logs and discharge prevention meeting logs shall be included in sections 1.8.3.1 and 1.8.3.2 of the response plan respectively. These logs may be included in the facility response plan or kept as an annex to the facility response plan.

1.8.3.1 Personnel Response Training Logs

PERSONNEL RESPONSE TRAINING LOG

Name	Response training/date and number of hours	Prevention training/date and number of hours

1.8.3.2 Discharge Prevention Meetings Logs

DISCHARGE PREVENTION MEETING LOG

Date: _____
Attendees: _____

Subject/issue identified	Required action	Implementation date

1.9 Diagrams

The facility-specific response plan shall include the following diagrams. Additional diagrams that would aid in the development of response plan sections may also be included.

(1) The Site Plan Diagram shall, as appropriate, include and identify:
(A) the entire facility to scale;
(B) above and below ground bulk oil storage tanks;
(C) the contents and capacities of bulk oil storage tanks;
(D) the contents and capacity of drum oil storage areas;
(E) the contents and capacities of surface impoundments;
(F) process buildings;
(G) transfer areas;
(H) secondary containment systems (location and capacity);
(I) structures where hazardous materials are stored or handled, including materials stored and capacity of storage;
(J) location of communication and emergency response equipment;
(K) location of electrical equipment which contains oil; and
(L) for complexes only, the interface(s) (i.e., valve or component) between the portion of the facility regulated by EPA and the portion(s) regulated by other Agencies. In most cases, this interface is defined as the last valve inside secondary containment before piping leaves the secondary containment area to connect to the transportation-related portion of the facility (i.e., the structure used or intended to be used to transfer oil to or from a vessel or pipeline). In the absence of secondary containment, this interface is the valve manifold adjacent to the tank nearest the transfer structure as described above. The interface may be defined differently at a specific facility if agreed to by the RA and the appropriate Federal official.

(2) The Site Drainage Plan Diagram shall, as appropriate, include:
(A) major sanitary and storm sewers, manholes, and drains;
(B) weirs and shut-off valves;
(C) surface water receiving streams;
(D) fire fighting water sources;
(E) other utilities;
(F) response personnel ingress and egress;
(G) response equipment transportation routes; and
(H) direction of discharge flow from discharge points.

(3) The Site Evacuation Plan Diagram shall, as appropriate, include:
(A) site plan diagram with evacuation route(s); and
(B) location of evacuation regrouping areas.

1.10 Security

According to 40 CFR 112.7(g) facilities are required to maintain a certain level of security, as appropriate. In this section, a description of the facility security shall be provided and include, as appropriate:

(1) emergency cut-off locations (automatic or manual valves);
(2) enclosures (e.g., fencing, etc.);
(3) guards and their duties, day and night;
(4) lighting;
(5) valve and pump locks; and
(6) pipeline connection caps.

The SPCC Plan contains similar information. Duplicate information may be photocopied and inserted in this section.

2.0 Response Plan Cover Sheet

A three-page form has been developed to be completed and submitted to the RA by owners or operators who are required to prepare and submit a facility-specific response plan. The cover sheet (Attachment F–1) must accompany the response plan to provide the Agency with basic information concerning the facility. This section will describe the Response Plan Cover Sheet and provide instructions for its completion.

2.1 General Information

Owner/Operator of Facility: Enter the name of the owner of the facility (if the owner is the operator). Enter the operator of the facility if otherwise. If the owner/operator of

the facility is a corporation, enter the name of the facility's principal corporate executive. Enter as much of the name as will fit in each section.

(1) *Facility Name:* Enter the proper name of the facility.

(2) *Facility Address:* Enter the street address, city, State, and zip code.

(3) *Facility Phone Number:* Enter the phone number of the facility.

(4) *Latitude and Longitude:* Enter the facility latitude and longitude in degrees, minutes, and seconds.

(5) *Dun and Bradstreet Number:* Enter the facility's Dun and Bradstreet number if available (this information may be obtained from public library resources).

(6) North American Industrial Classification System (NAICS) Code: Enter the facility's NAICS code as determined by the Office of Management and Budget (this information may be obtained from public library resources.)

(7) *Largest Oil Storage Tank Capacity:* Enter the capacity in GALLONS of the largest aboveground oil storage tank at the facility.

(8) *Maximum Oil Storage Capacity:* Enter the total maximum capacity in GALLONS of all aboveground oil storage tanks at the facility.

(9) *Number of Oil Storage Tanks:* Enter the number of all aboveground oil storage tanks at the facility.

(10) *Worst Case Discharge Amount:* Using information from the worksheets in appendix D, enter the amount of the worst case discharge in GALLONS.

(11) *Facility Distance to Navigable Waters:* Mark the appropriate line for the nearest distance between an opportunity for discharge (i.e., oil storage tank, piping, or flowline) and a navigable water.

2.2 Applicability of Substantial Harm Criteria

Using the flowchart provided in Attachment C–I to appendix C to this part, mark the appropriate answer to each question. Explanations of referenced terms can be found in Appendix C to this part. If a comparable formula to the ones described in Attachment C–III to appendix C to this part is used to calculate the planning distance, documentation of the reliability and analytical soundness of the formula must be attached to the response plan cover sheet.

2.3 Certification

Complete this block after all other questions have been answered.

3.0 Acronyms

ACP: Area Contingency Plan
ASTM: American Society of Testing Materials
bbls: Barrels
bpd: Barrels per Day
bph: Barrels per Hour
CHRIS: Chemical Hazards Response Information System
CWA: Clean Water Act
DOI: Department of Interior
DOC: Department of Commerce
DOT: Department of Transportation
EPA: Environmental Protection Agency
FEMA: Federal Emergency Management Agency
FR: Federal Register
gal: Gallons
gpm: Gallons per Minute
HAZMAT: Hazardous Materials
LEPC: Local Emergency Planning Committee
MMS: Minerals Management Service (part of DOI)
NAICS: North American Industrial Classification System
NCP: National Oil and Hazardous Substances Pollution Contingency Plan
NOAA: National Oceanic and Atmospheric Administration (part of DOC)
NRC: National Response Center
NRT: National Response Team
OPA: Oil Pollution Act of 1990
OSC: On-Scene Coordinator
PREP: National Preparedness for Response Exercise Program
RA: Regional Administrator
RCRA: Resource Conservation and Recovery Act
RRC: Regional Response Centers
RRT: Regional Response Team
RSPA: Research and Special Programs Administration
SARA: Superfund Amendments and Reauthorization Act
SERC: State Emergency Response Commission
SDWA: Safe Drinking Water Act of 1986
SI: Surface Impoundment
SPCC: Spill Prevention, Control, and Countermeasures
USCG: United States Coast Guard

4.0 References

CONCAWE. 1982. Methodologies for Hazard Analysis and Risk Assessment in the Petroleum Refining and Storage Industry. Prepared by CONCAWE's Risk Assessment Adhoc Group.

U.S. Department of Housing and Urban Development. 1987. Siting of HUD-Assisted Projects Near Hazardous Facilities: Acceptable Separation Distances from Explosive and Flammable Hazards. Prepared by the Office of Environment and Energy, Environmental Planning Division, Department of Housing and Urban Development. Washington, DC.

U.S. DOT, FEMA and U.S. EPA. Handbook of Chemical Hazard Analysis Procedures.

U.S. DOT, FEMA and U.S. EPA. Technical Guidance for Hazards Analysis: Emergency

Planning for Extremely Hazardous Substances.

The National Response Team. 1987. Hazardous Materials Emergency Planning Guide. Washington, DC.

The National Response Team. 1990. Oil Spill Contingency Planning, National Status: A Report to the President. Washington, DC. U.S. Government Printing Office.

Offshore Inspection and Enforcement Division. 1988. Minerals Management Service, Offshore Inspection Program: National Potential Incident of Noncompliance (PINC) List. Reston, VA.

ATTACHMENTS TO APPENDIX F

Attachment F–1—Response Plan Cover Sheet

This cover sheet will provide EPA with basic information concerning the facility. It must accompany a submitted facility response plan. Explanations and detailed instructions can be found in appendix F. Please type or write legibly in blue or black ink. Public reporting burden for the collection of this information is estimated to vary from 1 hour to 270 hours per response in the first year, with an average of 5 hours per response. This estimate includes time for reviewing instructions, searching existing data sources, gathering the data needed, and completing and reviewing the collection of information. Send comments regarding the burden estimate of this information, including suggestions for reducing this burden to: Chief, Information Policy Branch, Mail Code: PM–2822, U.S. Environmental Protection Agency, Ariel Rios Building, 1200 Pennsylvania Avenue, NW., Washington, DC 20460; and to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington D.C. 20503.

GENERAL INFORMATION

Owner/Operator of Facility: _____

Facility Name: _____

Facility Address (street address or route): _____

City, State, and U.S. Zip Code: _____

Facility Phone No.: _____

Latitude (Degrees: North): _____

degrees, minutes, seconds _____

Dun & Bradstreet Number:[1] _____

Largest Aboveground Oil Storage Tank Capacity (Gallons): _____

Number of Aboveground Oil Storage Tanks: _____

Longitude (Degrees: West): _____

degrees, minutes, seconds _____

North American Industrial Classification System (NAICS) Code:[1] _____

Maximum Oil Storage Capacity (Gallons): _____

Worst Case Oil Discharge Amount (Gallons): _____

Facility Distance to Navigable Water. Mark the appropriate line. _____

0–¼ mile ____ ¼–½ mile ____ ½–1 mile ____ >1 mile ____

APPLICABILITY OF SUBSTANTIAL HARM CRITERIA

Does the facility transfer oil over-water[2] to or from vessels and does the facility have a total oil storage capacity greater than or equal to 42,000 gallons?

Yes _____

No _____

Does the facility have a total oil storage capacity greater than or equal to 1 million gallons and, within any storage area, does the facility lack secondary containment[2] that is sufficiently large to contain the capacity of the largest aboveground oil storage tank plus sufficient freeboard to allow for precipitation?

Yes _____

No _____

Does the facility have a total oil storage capacity greater than or equal to 1 million gallons and is the facility located at a distance[2] (as calculated using the appropriate formula in appendix C or a comparable formula) such that a discharge from the facility could cause injury to fish and wildlife and sensitive environments?[3]

Yes _____

No _____

Does the facility have a total oil storage capacity greater than or equal to 1 million gallons and is the facility located at a distance[2] (as calculated using the appropriate formula in appendix C or a comparable formula) such that a discharge from the facility would shut down a public drinking water intake?[2] _____

Yes _____

[1] These numbers may be obtained from public library resources.

[2] Explanations of the above-referenced terms can be found in appendix C to this part. If a comparable formula to the ones contained in Attachment C–III is used to establish the appropriate distance to fish and wildlife and sensitive environments or public drinking water intakes, documentation of the reliability and analytical soundness of the formula must be attached to this form.

[3] For further description of fish and wildlife and sensitive environments, see Appendices I, II, and III to DOC/NOAA's ''Guidance for Facility and Vessel Response Plans: Fish and Wildlife and Sensitive Environments'' (see appendix E to this part, section 13, for availability) and the applicable ACP.

No _____

Does the facility have a total oil storage capacity greater than or equal to 1 million gallons and has the facility experienced a reportable oil spill[2] in an amount greater than or equal to 10,000 gallons within the last 5 years?

Yes _____

No _____

CERTIFICATION

I certify under penalty of law that I have personally examined and am familiar with the information submitted in this document, and that based on my inquiry of those individuals responsible for obtaining information, I believe that the submitted information is true, accurate, and complete.

Signature: _____

Name (Please type or print): _____

Title: _____

Date: _____

[59 FR 34122, July 1, 1994; 59 FR 49006, Sept. 26, 1994, as amended at 65 FR 40816, June 30, 2000; 65 FR 43840, July 14, 2000; 66 FR 34561, June 29, 2001; 67 FR 47152, July 17, 2002]

APPENDIX G TO PART 112—TIER I QUALIFIED FACILITY SPCC PLAN

Tier I Qualified Facility SPCC Plan

This template constitutes the SPCC Plan for the facility, when completed and signed by the owner or operator of a facility that meets the applicability criteria in §112.3(g)(1). This template addresses the requirements of 40 CFR part 112. Maintain a complete copy of the Plan at the facility if the facility is normally attended at least four hours per day, or for a facility attended fewer than four hours per day, at the nearest field office. When making operational changes at a facility that are necessary to comply with the rule requirements, the owner/operator should follow state and local requirements (such as for permitting, design and construction) and obtain professional assistance, as appropriate.

Facility Description

Facility Name _____

Facility Address _____

City _____ State _____ ZIP _____

County _____ Tel. Number ( ) - _____

Owner or operator Name _____

Owner or operator Address _____

City _____ State _____ ZIP _____

County _____ Tel. Number ( ) - _____

I. Self-Certification Statement (§112.6(a)(1))

The owner or operator of a facility certifies that each of the following is true in order to utilize this template to comply with the SPCC requirements:

I _____, certify that the following is accurate:

1. I am familiar with the applicable requirements of 40 CFR part 112;
2. I have visited and examined the facility;
3. This Plan was prepared in accordance with accepted and sound industry practices and standards;
4. Procedures for required inspections and testing have been established in accordance with industry inspection and testing standards or recommended practices;
5. I will fully implement the Plan;
6. This facility meets the following qualification criteria (under §112.3(g)(1)):
   a. The aggregate aboveground oil storage capacity of the facility is 10,000 U.S. gallons or less; and
   b. The facility has had no single discharge as described in §112.1(b) exceeding 1,000 U.S. gallons and no two discharges as described in §112.1(b) each exceeding 42 U.S. gallons within any twelve month period in the three years prior to the SPCC Plan self-certification date, or since becoming subject to 40 CFR part 112 if the facility has been in operation for less than three years (not including oil discharges as described in §112.1(b) that are the result of natural disasters, acts of war, or terrorism); and

c. There is no individual oil storage container at the facility with an aboveground capacity greater than 5,000 U.S. gallons.

7. This Plan does not deviate from any requirement of 40 CFR part 112 as allowed by §112.7(a)(2) (environmental equivalence) and §112.7(d) (impracticability of secondary containment) or include an measures pursuant to §112.9(c)(6) for produced water containers and any associated piping;
8. This Plan and individual(s) responsible for implementing this Plan have the full approval of management and I have committed the necessary resources to fully implement this Plan.

I also understand my other obligations relating to the storage of oil at this facility, including, among others:

1. To report any oil discharge to navigable waters or adjoining shorelines to the appropriate authorities. Notification information is included in this Plan.
2. To review and amend this Plan whenever there is a material change at the facility that affects the potential for an oil discharge, and at least once every five years. Reviews and amendments are recorded in an attached log [See Five Year Review Log and Technical Amendment Log in Attachments 1.1 and 1.2.]
3. Optional use of a contingency plan. A contingency plan:
   a. May be used in lieu of secondary containment for qualified oil-filled operational equipment, in accordance with the requirements under §112.7(k), and;
   b. Must be prepared for flowlines and/or intra-facility gathering lines which do not have secondary containment at an oil production facility, and;
   c. Must include an established and documented inspection or monitoring program; must follow the provisions of 40 CFR part 109; and must include a written commitment of manpower, equipment and materials to expeditiously remove any quantity of oil discharged that may be harmful. If applicable, a copy of the contingency plan and any additional documentation will be attached to this Plan as Attachment 2.

I certify that I have satisfied the requirement to prepare and implement a Plan under §112.3 and all of the requirements under §112.6(a). I certify that the information contained in this Plan is true.

Signature _____ Title: _____

Name _____ Date: ____/_____/20___

II. Record of Plan Review and Amendments

Five Year Review (§112.5(b)):

Complete a review and evaluation of this SPCC Plan at least once every five years. As a result of the review, amend this Plan within six months to include more effective prevention and control measures for the facility, if applicable. Implement any SPCC Plan amendment as soon as possible, but no later than six months following Plan amendment. Document completion of the review and evaluation, and complete the Five Year Review Log in Attachment 1.1. If the facility no longer meets Tier I qualified facility eligibility, the owner or operator must revise the Plan to meet Tier II qualified facility requirements, or complete a full PE certified Plan.

Table G-1 Technical Amendments (§§112.5(a), (c) and 112.6(a)(2))	
This SPCC Plan will be amended when there is a change in the facility design, construction, operation, or maintenance that materially affects the potential for a discharge to navigable waters or adjoining shorelines. Examples include adding or removing containers, reconstruction, replacement, or installation of piping systems, changes to secondary containment systems, changes in product stored at this facility, or revisions to standard operating procedures.	☐
Any technical amendments to this Plan will be re-certified in accordance with Section I of this Plan template. *[§112.6(a)(2)]* [See Technical Amendment Log in Attachment 1.2]	☐

III. Plan Requirements

1. Oil Storage Containers (§112.7(a)(3)(i)):

Table G-2 Oil Storage Containers and Capacities		
This table includes a complete list of all oil storage containers (aboveground containers[a] and completely buried tanks[b]) with capacity of 55 U.S. gallons or more, unless otherwise exempt from the rule. For mobile/portable containers, an estimate number of containers, types of oil, and anticipated capacities are provided.		☐
Oil Storage Container *(indicate whether aboveground (A) or completely buried (B))*	**Type of Oil**	**Shell Capacity (gallons)**
	Total Aboveground Storage Capacity [c]	_____ gallons
	Total Completely Buried Storage Capacity	_____ gallons
	Facility Total Oil Storage Capacity	_____ gallons

[a] Aboveground storage containers that must be included when calculating total facility oil storage capacity include: tanks and mobile or portable containers; oil-filled operational equipment (e.g. transformers); other oil-filled equipment, such as flow-through process equipment. Exempt containers that are not included in the capacity calculation include: any container with a storage capacity of less than 55 gallons of oil; containers used exclusively for wastewater treatment; permanently closed containers; motive power containers; hot-mix asphalt containers; heating oil containers used solely at a single-family residence; and pesticide application equipment or related mix containers.

[b] Although the criteria to determine eligibility for qualified facilities focuses on the aboveground oil storage containers at the facility, the completely buried tanks at a qualified facility are still subject to the rule requirements and must be addressed in the template; however, they are not counted toward the qualified facility applicability threshold.

[c] Counts toward qualified facility applicability threshold.

2. Secondary Containment and Oil Spill Control (§§112.6(a)(3)(i) and (ii), 112.7(c) and 112.9(c)(2)):

Table G-3 Secondary Containment and Oil Spill Control	
Appropriate secondary containment and/or diversionary structures or equipment[a] is provided for all oil handling containers, equipment, and transfer areas to prevent a discharge to navigable waters or adjoining shorelines. The entire secondary containment system, including walls and floor, is capable of containing oil and is constructed so that any discharge from a primary containment system, such as a tank or pipe, will not escape the containment system before cleanup occurs.	☐

[a] Use one of the following methods of secondary containment or its equivalent: (1) Dikes, berms, or retaining walls sufficiently impervious to contain oil; (2) Curbing; (3) Culverting, gutters, or other drainage systems; (4) Weirs, booms, or other barriers; (5) Spill diversion ponds; (6) Retention ponds; or (7) Sorbent materials.

Table G-4 below identifies the tanks and containers at the facility with the potential for an oil discharge; the mode of failure; the flow direction and potential quantity of the discharge; and the secondary containment method and containment capacity that is provided.

Table G-4 Containers with Potential for an Oil Discharge

Area	Type of failure (discharge scenario)	Potential discharge volume (galions)	Direction of flow for uncontained discharge	Secondary containment method[a]	Secondary containment capacity (gallons)
Bulk Storage Containers and Mobile/Portable Containers[b]					
Oil-filled Operational Equipment (e.g., hydraulic equipment, transformers)[c]					
Piping, Valves, etc.					
Product Transfer Areas (location where oil is loaded to or from a container, pipe or other piece of equipment.)					
Other Oil-Handling Areas or Oil-Filled Equipment (e.g. flow-through process vessels at an oil production facility)					

[a] Use one of the following methods of secondary containment or its equivalent: (1) Dikes, berms, or retaining walls sufficiently impervious to contain oil; (2) Curbing; (3) Culverting, gutters, or other drainage systems; (4) Weirs, booms, or other barriers; (5) Spill diversion ponds; (6) Retention ponds; or (7) Sorbent materials.

[b] For storage tanks and bulk storage containers, the secondary containment capacity must be at least the capacity of the largest container plus additional capacity to contain rainfall or other precipitation.

[c] For oil-filled operational equipment: Document in the table above if alternative measures to secondary containment (as described in §112.7(k)) are implemented at the facility.

3. Inspections, Testing, Recordkeeping and Personnel Training (§§112.7(e) and (f), 112.8(c)(6) and (d)(4), 112.9(c)(3), 112.12(c)(6) and (d)(4)):

Table G-5 Inspections, Testing, Recordkeeping and Personnel Training	
An inspection and/or testing program is implemented for all aboveground bulk storage containers and piping at this facility. *[§§112.8(c)(6) and (d)(4), 112.9(c)(3), 112.12(c)(6) and (d)(4)]*	☐
The following is a description of the inspection and/or testing program (e.g. reference to industry standard utilized, scope, frequency, method of inspection or test, and person conducting the inspection) for all aboveground bulk storage containers and piping at this facility:	
Inspections, tests, and records are conducted in accordance with written procedures developed for the facility. Records of inspections and tests kept under usual and customary business practices will suffice for purposes of this paragraph. *[§112.7(e)]*	☐
A record of the inspections and tests are kept at the facility or with the SPCC Plan for a period of three years. *[§112.7(e)]* [See Inspection Log and Schedule in Attachment 3.1]	☐
Inspections and tests are signed by the appropriate supervisor or inspector. *[§112.7(e)]*	☐
Personnel, training, and discharge prevention procedures [§112.7(f)]	
Oil-handling personnel are trained in the operation and maintenance of equipment to prevent discharges; discharge procedure protocols; applicable pollution control laws, rules, and regulations; general facility operations; and, the contents of the facility SPCC Plan. *[§112.7(f)]*	☐
A person who reports to facility management is designated and accountable for discharge prevention. *[§112.7(f)]* Name/Title:_____	☐
Discharge prevention briefings are conducted for oil-handling personnel annually to assure adequate understanding of the SPCC Plan for that facility. Such briefings highlight and describe past reportable discharges or failures, malfunctioning components, and any recently developed precautionary measures. *[§112.7(f)]* [See Oil-handling Personnel Training and Briefing Log in Attachment 3.4]	☐

4. Security (excluding oil production facilities) §112.7(g):

Table G-6 Implementation and Description of Security Measures	
Security measures are implemented at this facility to prevent unauthorized access to oil handling, processing, and storage area.	☐
The following is a description of how you secure and control access to the oil handling, processing and storage areas; secure master flow and drain valves; prevent unauthorized access to starter controls on oil pumps; secure out-of-service and loading/unloading connections of oil pipelines; address the appropriateness of security lighting to both prevent acts of vandalism and assist in the discovery of oil discharges:	

5. Emergency Procedures and Notifications (§112.7(a)(3)(iv) and 112.7(a)(5)):

Table G-7 Description of Emergency Procedures and Notifications
The following is a description of the immediate actions to be taken by facility personnel in the event of a discharge to navigable waters or adjoining shorelines *[§112.7(a)(3)(iv) and 112.7(a)(5)]*:

6. Contact List (§112.7(a)(3)(vi)):

Table G-8 Contact List	
Contact Organization / Person	**Telephone Number**
National Response Center (NRC)	1-800-424-8802
Cleanup Contractor(s)	
Key Facility Personnel	
Designated Person Accountable for Discharge Prevention:	Office:
	Emergency:
	Office:
	Emergency:
	Office:
	Emergency:
	Office:
	Emergency:
State Oil Pollution Control Agencies	
Other State, Federal, and Local Agencies	
Local Fire Department	
Local Police Department	
Hospital	
Other Contact References (e.g., downstream water intakes or neighboring facilities)	

7. NRC Notification Procedure (§112.7(a)(4) and (a)(5)):

Table G-9 NRC Notification Procedure	
In the event of a discharge of oil to navigable waters or adjoining shorelines, the following information identified in Attachment 4 will be provided to the National Response Center immediately following identification of a discharge to navigable waters or adjoining shorelines [See Discharge Notification Form in Attachment 4]: *[§112.7(a)(4)]*	☐
• The exact address or location and phone number of the facility; • Date and time of the discharge; • Type of material discharged; • Estimate of the total quantity discharged; • Estimate of the quantity discharged to navigable waters; • Source of the discharge; • Description of all affected media; • Cause of the discharge; • Any damages or injuries caused by the discharge; • Actions being used to stop, remove, and mitigate the effects of the discharge; • Whether an evacuation may be needed; and • Names of individuals and/or organizations who have also been contacted.	

8. SPCC Spill Reporting Requirements (Report within 60 days) (§112.4):

Submit information to the EPA Regional Administrator (RA) and the appropriate agency or agencies in charge of oil pollution control activities in the State in which the facility is located within 60 days from one of the following discharge events:

- A single discharge of more than 1,000 U.S. gallons of oil to navigable waters or adjoining shorelines or
- Two discharges to navigable waters or adjoining shorelines each more than 42 U.S. gallons of oil occurring within any twelve month period

You must submit the following information to the RA:

(1) Name of the facility;
(2) Your name;
(3) Location of the facility;
(4) Maximum storage or handling capacity of the facility and normal daily throughput;
(5) Corrective action and countermeasures you have taken, including a description of equipment repairs and replacements;
(6) An adequate description of the facility, including maps, flow diagrams, and topographical maps, as necessary;
(7) The cause of the reportable discharge, including a failure analysis of the system or subsystem in which the failure occurred; and
(8) Additional preventive measures you have taken or contemplated to minimize the possibility of recurrence
(9) Such other information as the Regional Administrator may reasonably require pertinent to the Plan or discharge

* * * * *

NOTE: Complete one of the following sections (A, B or C)

as appropriate for the facility type.

A. Onshore Facilities (excluding production) (§§112.8(b) through (d), 112.12(b) through (d)):

The owner or operator must meet the general rule requirements as well as requirements under this section. Note that not all provisions may be applicable to all owners/operators. For example, a facility may not maintain completely buried metallic storage tanks installed after January 10, 1974, and thus would not have to abide by requirements in §§112.8(c)(4) and 112.12(c)(4), listed below. In cases where a provision is not applicable, write "N/A".

Table G-10 General Rule Requirements for Onshore Facilities	
Drainage from diked storage areas is restrained by valves to prevent a discharge into the drainage system or facility effluent treatment system, except where facility systems are designed to control such discharge. Diked areas may be emptied by pumps or ejectors that must be manually activated after inspecting the condition of the accumulation to ensure no oil will be discharged. *[§§112.8(b)(1) and 112.12(b)(1)]*	☐
Valves of manual, open-and-closed design are used for the drainage of diked areas. *[§§112.8(b)(2) and 112.12(b)(2)]*	☐
The containers at the facility are compatible with materials stored and conditions of storage such as pressure and temperature. *[§§112.8(c)(1) and 112.12(c)(1)]*	☐
Secondary containment for the bulk storage containers (including mobile/portable oil storage containers) holds the capacity of the largest container plus additional capacity to contain precipitation. Mobile or portable oil storage containers are positioned to prevent a discharge as described in §112.1(b). *[§112.6(a)(3)(ii)]*	☐
If uncontaminated rainwater from diked areas drains into a storm drain or open watercourse the following procedures will be implemented at the facility: *[§§112.8(c)(3) and 112.12(c)(3)]*	
• Bypass valve is normally sealed closed	☐
• Retained rainwater is inspected to ensure that its presence will not cause a discharge to navigable waters or adjoining shorelines	☐
• Bypass valve is opened and resealed under responsible supervision	☐
• Adequate records of drainage are kept [See Dike Drainage Log in Attachment 3.3]	☐
For completely buried metallic tanks installed on or after January 10, 1974 at this facility *[§§112.8(c)(4) and 112.12(c)(4)]*:	
• Tanks have corrosion protection with coatings or cathodic protection compatible with local soil conditions.	☐
• Regular leak testing is conducted.	☐
For partially buried or bunkered metallic tanks *[§112.8(c)(5) and §112.12(c)(5)]*:	
• Tanks have corrosion protection with coatings or cathodic protection compatible with local soil conditions.	☐
Each aboveground bulk container is tested or inspected for integrity on a regular schedule and whenever material repairs are made. Scope and frequency of the inspections and inspector qualifications are in accordance with industry standards. Container supports and foundations are regularly inspected. [See Inspection Log and Schedule and Bulk Storage Container Inspection Schedule in Attachments 3.1 and 3.2] *[§112.8(c)(6) and §112.12(c)(6)(i)]*	☐
Outsides of bulk storage containers are frequently inspected for signs of deterioration, discharges, or accumulation of oil inside diked areas. [See Inspection Log and Schedule in Attachment 3.1] *[§§112.8(c)(6) and 112.12(c)(6)]*	☐
For bulk storage containers that are subject to 21 CFR part 110 which are shop-fabricated, constructed of austenitic stainless steel, elevated and have no external insulation, formal visual inspection is conducted on a regular schedule. Appropriate qualifications for personnel performing tests and inspections are documented. [See Inspection Log and Schedule and Bulk	☐

Table G-10 General Rule Requirements for Onshore Facilities	
Storage Container Inspection Schedule in Attachments 3.1 and 3.2] *[§112.12(c)(6)(ii)]*	
Each container is provided with a system or documented procedure to prevent overfills for the container. Describe:	☐
Liquid level sensing devices are regularly tested to ensure proper operation [See Inspection Log and Schedule in Attachment 3.1]. *[§112.6(a)(3)(iii)]*	☐
Visible discharges which result in a loss of oil from the container, including but not limited to seams, gaskets, piping, pumps, valves, rivets, and bolts are promptly corrected and oil in diked areas is promptly removed. *[§§112.8(c)(10) and 112.12(c)(10)]*	☐
Aboveground valves, piping, and appurtenances such as flange joints, expansion joints, valve glands and bodies, catch pans, pipeline supports, locking of valves, and metal surfaces are inspected regularly. [See Inspection Log and Schedule in Attachment 3.1] *[§§112.8(d)(4) and 112.12(d)(4)]*	☐
Integrity and leak testing are conducted on buried piping at the time of installation, modification, construction, relocation, or replacement. [See Inspection Log and Schedule in Attachment 3.1] *[§§112.8(d)(4) and 112.12(d)(4)]*	☐

B. Onshore Oil Production Facilities (excluding drilling and workover facilities) (§112.9(b), (c), and (d)):

The owner or operator must meet the general rule requirements as well as the requirements under this section. Note that not all provisions may be applicable to all owners/operators. In cases where a provision is not applicable, write "N/A".

Table G-11 General Rule Requirements for Onshore Oil Production Facilities	
At tank batteries, separation and treating areas, drainage is closed and sealed except when draining uncontaminated rainwater. Accumulated oil on the rainwater is returned to storage or disposed of in accordance with legally approved methods. *[§112.9(b)(1)]*	☐
Prior to drainage, diked areas are inspected and *[§112.9(b)(1)]*:	
• Retained rainwater is inspected to ensure that its presence will not cause a discharge to navigable waters	☐
• Bypass valve is opened and resealed under responsible supervision	☐
• Adequate records of drainage are kept [See Dike Drainage Log in Attachment 3.3]	☐
Field drainage systems and oil traps, sumps, or skimmers are inspected at regularly scheduled intervals for oil, and accumulations of oil are promptly removed [See Inspection Log and Schedule in Attachment 3.1] *[§112.9(b)(2)]*	☐
The containers used at this facility are compatible with materials stored and conditions of storage. *[§112.9(c)(1)]*	☐
All tank battery, separation, and treating facility installations (except for flow-through process vessels) are constructed with a capacity to hold the largest single container plus additional capacity to contain rainfall. Drainage from undiked areas is safely confined in a catchment basin or holding pond. *[§112.9(c)(2)]*	☐
Except for flow-through process vessels, containers that are on or above the surface of the ground, including foundations and supports, are visually inspected for deterioration and maintenance needs on a regular schedule. [See Inspection Log and Schedule in Attachment 3.1] *[§112.9(c)(3)]*	☐
New and old tank batteries at this facility are engineered/updated in accordance with good engineering practices to prevent discharges including at least one of the following: (i) adequate container capacity to prevent overfill if regular pumping/gauging is delayed; (ii) overflow equalizing lines between containers so that a full container can overflow to an adjacent container; (iii) vacuum protection to prevent container collapse; or (iv) high level sensors to generate and transmit an alarm to the computer where the facility is subject to a computer production control system. *[§112.9(c)(4)]*	☐
Flow-through process vessels and associated components are:	
• Are constructed with a capacity to hold the largest single container plus additional capacity to contain rainfall. Drainage from undiked areas is safely confined in a catchment basin or holding pond; *[§112.9(c)(2)]* and	☐
• That are on or above the surface of the ground, including foundations and supports, are visually inspected for deterioration and maintenance needs on a regular schedule. [See Inspection Log and Schedule in Attachment 3.1] *[§112.9(c)(3)]*	☐
Or	
• Visually inspected and/or tested periodically and on a regular schedule for leaks, corrosion, or other conditions that could lead to a discharge to navigable waters; and	☐
• Corrective action or repairs are applied to flow-through process vessels and any associated components as indicated by regularly scheduled visual inspections, tests, or evidence of an oil discharge; and	☐
• Any accumulations of oil discharges associated with flow-through process vessels are promptly removed; and	☐

Table G-11 General Rule Requirements for Onshore Oil Production Facilities	
• Flow-through process vessels are provided with a secondary means of containment for the entire capacity of the largest single container and sufficient freeboard to contain precipitation within six months of a discharge from flow-through process vessels of more than 1,000 U.S. gallons of oil in a single discharge as described in §112.1(b), or a discharge more than 42 U.S. gallons of oil in each of two discharges as described in §112.1(b) within any twelve month period. *[§112.9(c)(5)]* *(Leave blank until such time that this provision is applicable.)*	☐
All aboveground valves and piping associated with transfer operations are inspected periodically and upon a regular schedule. The general condition of flange joints, valve glands and bodies, drip pans, pipe supports, pumping well polish rod stuffing boxes, bleeder and gauge valves, and other such items are included in the inspection. [See Inspection Log and Schedule in Attachment 3.1] *[§112.9(d)(1)]*	☐
An oil spill contingency plan and written commitment of resources are provided for flowlines and intra-facility gathering lines [See Oil Spill Contingency Plan and Checklist in Attachment 2 and Inspection Log and Schedule in Attachment 3.1] *[§112.9(d)(3)]*	☐
or Appropriate secondary containment and/or diversionary structures or equipment is provided for flowlines and intra-facility gathering lines to prevent a discharge to navigable waters or adjoining shorelines. The entire secondary containment system, including walls and floor, is capable of containing oil and is constructed so that any discharge from the pipe, will not escape the containment system before cleanup occurs.	☐
A flowline/intra-facility gathering line maintenance program to prevent discharges from each flowline has been established at this facility. The maintenance program addresses each of the following:	☐
• Flowlines and intra-facility gathering lines and associated valves and equipment are compatible with the type of production fluids, their potential corrosivity, volume, and pressure, and other conditions expected in the operational environment;	☐
• Flowlines, intra-facility gathering lines and associated appurtenances are visually inspected and/or tested on a periodic and regular schedule for leaks, oil discharges, corrosion, or other conditions that could lead to a discharge as described in §112.1(b). The frequency and type of testing allows for the implementation of a contingency plan as described under part 109 of this chapter.	☐
• Corrective action and repairs to any flowlines and intra-facility gathering lines and associated appurtenances as indicated by regularly scheduled visual inspections, tests, or evidence of a discharge.	☐
• Accumulations of oil discharges associated with flowlines, intra-facility gathering lines, and associated appurtenances are promptly removed. *[§112.9(d)(4)]*	☐
The following is a description of the flowline/intra-facility gathering line maintenance program implemented at this facility:	

C. Onshore Oil Drilling and Workover Facilities (§112.10(b), (c) and (d)):

The owner or operator must meet the general rule requirements as well as the requirements under this section.

Table G-12 General Rule Requirements for Onshore Oil Drilling and Workover Facilities	
Mobile drilling or worker equipment is positioned or located to prevent discharge as described in §112.1(b). *[§112.10(b)]*	☐
Catchment basins or diversion structures are provided to intercept and contain discharges of fuel, crude oil, or oily drilling fluids. *[§112.10(c)]*	☐
A blowout prevention (BOP) assembly and well control system was installed before drilling below any casing string or during workover operations. *[§112.10(d)]*	☐
The BOP assembly and well control system is capable of controlling any well-head pressure that may be encountered while the BOP assembly and well control system are on the well. *[§112.10(d)]*	☐

ATTACHMENT 1 – Five Year Review and Technical Amendment Logs

ATTACHMENT 1.1 – Five Year Review Log

I have completed a review and evaluation of the SPCC Plan for this facility, and will/will not amend this Plan as a result.

Table G-13 Review and Evaluation of SPCC Plan for Facility			
Review Date	Plan Amendment		Name and signature of person authorized to review this Plan
	Will Amend	Will Not Amend	
	☐	☐	
	☐	☐	
	☐	☐	
	☐	☐	
	☐	☐	
	☐	☐	
	☐	☐	
	☐	☐	

ATTACHMENT 1.2 – Technical Amendment Log

Any technical amendments to this Plan will be re-certified in accordance with Section I of this Plan template.

Table G-14 Description and Certification of Technical Amendments		
Review Date	Description of Technical Amendment	Name and signature of person certifying this technical amendment

ATTACHMENT 2 – Oil Spill Contingency Plan and Checklist

An oil spill contingency plan and written commitment of resources is required for:

- Flowlines and intra-facility gathering lines at oil production facilities and
- Qualified oil-filled operational equipment which has no secondary containment.

An oil spill contingency plan meeting the provisions of 40 CFR part 109, as described below, and a written commitment of manpower, equipment and materials required to expeditiously control and remove any quantity of oil discharged that may be harmful is attached to this Plan.	☐

Complete the checklist below to verify that the necessary operations outlined in 40 CFR part 109 - Criteria for State, Local and Regional Oil Removal Contingency Plans - have been included.

Table G-15 Checklist of Development and Implementation Criteria for State, Local and Regional Oil Removal Contingency Plans (§109.5)[a]	
(a) Definition of the authorities, responsibilities and duties of all persons, organizations or agencies which are to be involved in planning or directing oil removal operations.	☐
(b) Establishment of notification procedures for the purpose of early detection and timely notification of an oil discharge including:	
(1) The identification of critical water use areas to facilitate the reporting of and response to oil discharges.	☐
(2) A current list of names, telephone numbers and addresses of the responsible persons (with alternates) and organizations to be notified when an oil discharge is discovered.	☐
(3) Provisions for access to a reliable communications system for timely notification of an oil discharge, and the capability of interconnection with the communications systems established under related oil removal contingency plans, particularly State and National plans (e.g., NCP).	☐
(4) An established, prearranged procedure for requesting assistance during a major disaster or when the situation exceeds the response capability of the State, local or regional authority.	☐
(c) Provisions to assure that full resource capability is known and can be committed during an oil discharge situation including:	
(1) The identification and inventory of applicable equipment, materials and supplies which are available locally and regionally.	☐
(2) An estimate of the equipment, materials and supplies which would be required to remove the maximum oil discharge to be anticipated.	☐
(3) Development of agreements and arrangements in advance of an oil discharge for the acquisition of equipment, materials and supplies to be used in responding to such a discharge.	☐
(d) Provisions for well defined and specific actions to be taken after discovery and notification of an oil discharge including:	
(1) Specification of an oil discharge response operating team consisting of trained, prepared and available operating personnel.	☐
(2) Predesignation of a properly qualified oil discharge response coordinator who is charged with the responsibility and delegated commensurate authority for directing and coordinating response operations and who knows how to request assistance from Federal authorities operating under existing national and regional contingency plans.	☐

Table G-15 Checklist of Development and Implementation Criteria for State, Local and Regional Oil Removal Contingency Plans (§109.5)[a]	
(3) A preplanned location for an oil discharge response operations center and a reliable communications system for directing the coordinated overall response operations.	☐
(4) Provisions for varying degrees of response effort depending on the severity of the oil discharge.	☐
(5) Specification of the order of priority in which the various water uses are to be protected where more than one water use may be adversely affected as a result of an oil discharge and where response operations may not be adequate to protect all uses.	☐
(6) Specific and well defined procedures to facilitate recovery of damages and enforcement measures as provided for by State and local statutes and ordinances.	☐

[a] The contingency plan must be consistent with all applicable state and local plans, Area Contingency Plans, and the National Contingency Plan (NCP).

ATTACHMENT 3 – Inspections, Dike Drainage and Personnel Training Logs

ATTACHMENT 3.1 – Inspection Log and Schedule

Table G-16 Inspection Log and Schedule

This log is intended to document compliance with §§112.6(a)(3)(iii), 112.8(c)(6), 112.8(d)(4), 112.9(b)(2), 112.9(c)(3), 112.9(d)(1), 112.9(d)(4), 112.12.(c)(6), and 112.12(d)(4), as applicable.

Date of Inspection	Container / Piping / Equipment	Describe Scope (or cite Industry Standard)	Observations	Name/ Signature of Inspector	Records maintained separately [a]
					☐
					☐
					☐
					☐
					☐

[a] Indicate in the table above if records of facility inspections are maintained separately at this facility.

ATTACHMENT 3.2 – Bulk Storage Container Inspection Schedule – onshore facilities (excluding production):

To comply with integrity inspection requirement for bulk storage containers, inspect/test each shop-built aboveground bulk storage container on a regular schedule in accordance with a recognized container inspection standard based on the minimum requirements in the following table.

Table G-17 Bulk Storage Container Inspection Schedule	
Container Size and Design Specification	**Inspection requirement**
Portable containers (including drums, totes, and intermodal bulk containers (IBC))	Visually inspect monthly for signs of deterioration, discharges or accumulation of oil inside diked areas
55 to 1,100 gallons with sized secondary containment	Visually inspect monthly for signs of deterioration, discharges or accumulation of oil inside diked areas plus any annual inspection elements per industry inspection standards
1,101 to 5,000 gallons with sized secondary containment and a means of leak detection[a]	
1,101 to 5,000 gallons with sized secondary containment and no method of leak detection[a]	Visually inspect monthly for signs of deterioration, discharges or accumulation of oil inside diked areas, plus any annual inspection elements and other specific integrity tests that may be required per industry inspection standards

[a] Examples of leak detection include, but are not limited to, double-walled tanks and elevated containers where a leak can be visually identified.

ATTACHMENT 3.3 – Dike Drainage Log

Table G-18 Dike Drainage Log

Date	Bypass valve sealed closed	Rainwater inspected to be sure no oil (or sheen) is visible	Open bypass valve and reseal it following drainage	Drainage activity supervised	Observations	Signature of Inspector
	☐	☐	☐	☐		
	☐	☐	☐	☐		
	☐	☐	☐	☐		
	☐	☐	☐	☐		
	☐	☐	☐	☐		
	☐	☐	☐	☐		
	☐	☐	☐	☐		
	☐	☐	☐	☐		

ATTACHMENT 3.4 – Oil-handling Personnel Training and Briefing Log

Table G-19 Oil-Handling Personnel Training and Briefing Log		
Date	Description / Scope	Attendees

ATTACHMENT 4 – Discharge Notification Form

In the event of a discharge of oil to navigable waters or adjoining shorelines, the following information will be provided to the National Response Center [also see the notification information provided in Section 7 of the Plan]:

Table G-20 Information provided to the National Response Center in the Event of a Discharge			
Discharge/Discovery Date		Time	
Facility Name			
Facility Location (Address/Lat-Long/Section Township Range)			
Name of reporting individual		Telephone #	
Type of material discharged		Estimated total quantity discharged	Gallons/Barrels
Source of the discharge		Media affected	☐ Soil ☐ Water (specify) _____ ☐ Other (specify) _____
Actions taken			
Damage or injuries	☐ No ☐ Yes (specify)	Evacuation needed?	☐ No ☐ Yes (specify)
Organizations and individuals contacted	☐ National Response Center 800-424-8802 Time _____		
	☐ Cleanup contractor (Specify) Time _____		
	☐ Facility personnel (Specify) Time _____		
	☐ State Agency (Specify) Time _____		
	☐ Other (Specify) Time _____		

[74 FR 58811, Nov. 13, 2009]

PART 113—LIABILITY LIMITS FOR SMALL ONSHORE STORAGE FACILITIES

Subpart A—Oil Storage Facilities

Sec.
113.1 Purpose.
113.2 Applicability.
113.3 Definitions.
113.4 Size classes and associated liability limits for fixed onshore oil storage facilities, 1,000 barrels or less capacity.
113.5 Exclusions.
113.6 Effect on other laws.

AUTHORITY: Sec. 311(f)(2), 86 Stat. 867 (33 U.S.C. 1251 (1972)).

SOURCE: 38 FR 25440, Sept. 13, 1973, unless otherwise noted.

Subpart A—Oil Storage Facilities

§ 113.1 Purpose.

This subpart establishes size classifications and associated liability limits for small onshore oil storage facilities with fixed capacity of 1,000 barrels or less.

§ 113.2 Applicability.

This subpart applies to all onshore oil storage facilities with fixed capacity of 1,000 barrels or less. When a discharge to the waters of the United States occurs from such facilities and when removal of said discharge is performed by the United States Government pursuant to the provisions of subsection 311(c)(1) of the Act, the liability

(1) The identification and inventory of applicable equipment, materials and supplies which are available locally and regionally.

(2) An estimate of the equipment, materials and supplies which would be required to remove the maximum oil discharge to be anticipated.

(3) Development of agreements and arrangements in advance of an oil discharge for the acquisition of equipment, materials and supplies to be used in responding to such a discharge.

(d) Provisions for well defined and specific actions to be taken after discovery and notification of an oil discharge including:

(1) Specification of an oil discharge response operating team consisting of trained, prepared and available operating personnel.

(2) Predesignation of a properly qualified oil discharge response coordinator who is charged with the responsibility and delegated commensurate authority for directing and coordinating response operations and who knows how to request assistance from Federal authorities operating under existing national and regional contingency plans.

(3) A preplanned location for an oil discharge response operations center and a reliable communications system for directing the coordinated overall response operations.

(4) Provisions for varying degrees of response effort depending on the severity of the oil discharge.

(5) Specification of the order of priority in which the various water uses are to be protected where more than one water use may be adversely affected as a result of an oil discharge and where response operations may not be adequate to protect all uses.

(e) Specific and well defined procedures to facilitate recovery of damages and enforcement measures as provided for by State and local statutes and ordinances.

§ 109.6 Coordination.

For the purposes of coordination, the contingency plans of State and local governments should be developed and implemented in consultation with private interests. A copy of any oil removal contingency plan developed by State and local governments should be forwarded to the Council on Environmental Quality upon request to facilitate the coordination of these contingency plans with the National Oil and Hazardous Materials Pollution Contingency Plan.

PART 110—DISCHARGE OF OIL

Sec.

110.1 Definitions.
110.2 Applicability.
110.3 Discharge of oil in such quantities as ''may be harmful'' pursuant to section 311(b)(4) of the Act.
110.4 Dispersants.
110.5 Discharges of oil not determined ''as may be harmful'' pursuant to section 311(b)(3) of the Act.
110.6 Notice.

AUTHORITY: 33 U.S.C. 1321(b)(3) and (b)(4) and 1361(a); E.O. 11735, 38 FR 21243, 3 CFR Parts 1971–1975 Comp., p. 793.

SOURCE: 52 FR 10719, Apr. 2, 1987, unless otherwise noted.

§ 110.1 Definitions.

Terms not defined in this section have the same meaning given by the Section 311 of the Act. As used in this part, the following terms shall have the meaning indicated below:

Act means the Federal Water Pollution Control Act, as amended, 33 U.S.C. 1251 *et seq.*, also known as the Clean Water Act;

Administrator means the Administrator of the Environmental Protection Agency (EPA);

Applicable water quality standards means State water quality standards adopted by the State pursuant to section 303 of the Act or promulgated by EPA pursuant to that section;

MARPOL 73/78 means the International Convention for the Prevention of Pollution from Ships, 1973, as modified by the Protocol of 1978 relating thereto, Annex I, which regulates pollution from oil and which entered into force on October 2, 1983;

Navigable waters means the waters of the United States, including the territorial seas. The term includes:

(a) All waters that are currently used, were used in the past, or may be susceptible to use in interstate or foreign commerce, including all waters

that are subject to the ebb and flow of the tide;

(b) Interstate waters, including interstate wetlands;

(c) All other waters such as intrastate lakes, rivers, streams (including intermittent streams), mudflats, sandflats, and wetlands, the use, degradation, or destruction of which would affect or could affect interstate or foreign commerce including any such waters:

(1) That are or could be used by interstate or foreign travelers for recreational or other purposes;

(2) From which fish or shellfish are or could be taken and sold in interstate or foreign commerce;

(3) That are used or could be used for industrial purposes by industries in interstate commerce;

(d) All impoundments of waters otherwise defined as navigable waters under this section;

(e) Tributaries of waters identified in paragraphs (a) through (d) of this section, including adjacent wetlands; and

(f) Wetlands adjacent to waters identified in paragraphs (a) through (e) of this section: Provided, That waste treatment systems (other than cooling ponds meeting the criteria of this paragraph) are not waters of the United States;

Navigable waters do not include prior converted cropland. Notwithstanding the determination of an area's status as prior converted cropland by any other federal agency, for the purposes of the Clean Water Act, the final authority regarding Clean Water Act jurisdiction remains with EPA.

NPDES means National Pollutant Discharge Elimination System;

Sheen means an iridescent appearance on the surface of water;

Sludge means an aggregate of oil or oil and other matter of any kind in any form other than dredged spoil having a combined specific gravity equivalent to or greater than water;

United States means the States, the District of Columbia, the Commonwealth of Puerto Rico, Guam, American Samoa, the Virgin Islands, and the Trust Territory of the Pacific Islands;

Wetlands means those areas that are inundated or saturated by surface or ground water at a frequency or duration sufficient to support, and that under normal circumstances do support, a prevalence of vegetation typically adapted for life in saturated soil conditions. Wetlands generally include playa lakes, swamps, marshes, bogs and similar areas such as sloughs, prairie potholes, wet meadows, prairie river overflows, mudflats, and natural ponds.

[52 FR 10719, Apr. 2, 1987, as amended at 58 FR 45039, Aug. 25, 1993; 61 FR 7421, Feb. 28, 1996]

§ 110.2 Applicability.

The regulations of this part apply to the discharge of oil prohibited by section 311(b)(3) of the Act.

[61 FR 7421, Feb. 28, 1996]

§ 110.3 Discharge of oil in such quantities as "may be harmful" pursuant to section 311(b)(4) of the Act.

For purposes of section 311(b)(4) of the Act, discharges of oil in such quantities that the Administrator has determined may be harmful to the public health or welfare or the environment of the United States include discharges of oil that:

(a) Violate applicable water quality standards; or

(b) Cause a film or sheen upon or discoloration of the surface of the water or adjoining shorelines or cause a sludge or emulsion to be deposited beneath the surface of the water or upon adjoining shorelines.

[61 FR 7421, Feb. 28, 1996]

§ 110.4 Dispersants.

Addition of dispersants or emulsifiers to oil to be discharged that would circumvent the provisions of this part is prohibited.

[52 FR 10719, Apr. 2, 1987. Redesignated at 61 FR 7421, Feb. 28, 1996]

§ 110.5 Discharges of oil not determined "as may be harmful" pursuant to Section 311(b)(3) of the Act.

Notwithstanding any other provisions of this part, the Administrator has not determined the following discharges of oil ''as may be harmful'' for purposes of section 311(b) of the Act:

(a) Discharges of oil from a properly functioning vessel engine (including an

engine on a public vessel) and any discharges of such oil accumulated in the bilges of a vessel discharged in compliance with MARPOL 73/78, Annex I, as provided in 33 CFR part 151, subpart A;

(b) Other discharges of oil permitted under MARPOL 73/78, Annex I, as provided in 33 CFR part 151, subpart A; and

(c) Any discharge of oil explicitly permitted by the Administrator in connection with research, demonstration projects, or studies relating to the prevention, control, or abatement of oil pollution.

[61 FR 7421, Feb. 28, 1996]

§ 110.6 Notice.

Any person in charge of a vessel or of an onshore or offshore facility shall, as soon as he or she has knowledge of any discharge of oil from such vessel or facility in violation of section 311(b)(3) of the Act, immediately notify the National Response Center (NRC) (800–424–8802; in the Washington, DC metropolitan area, 202–426–2675). If direct reporting to the NRC is not practicable, reports may be made to the Coast Guard or EPA predesignated On-Scene Coordinator (OSC) for the geographic area where the discharge occurs. All such reports shall be promptly relayed to the NRC. If it is not possible to notify the NRC or the predesignated OCS immediately, reports may be made immediately to the nearest Coast Guard unit, provided that the person in charge of the vessel or onshore or offshore facility notifies the NRC as soon as possible. The reports shall be made in accordance with such procedures as the Secretary of Transportation may prescribe. The procedures for such notice are set forth in U.S. Coast Guard regulations, 33 CFR part 153, subpart B and in the National Oil and Hazardous Substances Pollution Contingency Plan, 40 CFR part 300, subpart E.

(Approved by the Office of Management and Budget under control number 2050–0046)

[52 FR 10719, Apr. 2, 1987. Redesignated and amended at 61 FR 7421, Feb. 28, 1996; 61 FR 14032, Mar. 29, 1996]

PART 112—OIL POLLUTION PREVENTION

Subpart A—Applicability, Definitions, and General Requirements For All Facilities and All Types of Oils

Sec.
112.1 General applicability.
112.2 Definitions.
112.3 Requirement to prepare and implement a Spill Prevention, Control, and Countermeasure Plan.
112.4 Amendment of Spill Prevention, Control, and Countermeasure Plan by Regional Administrator.
112.5 Amendment of Spill Prevention, Control, and Countermeasure Plan by owners or operators.
112.6 Qualified Facility Plan Requirements.
112.7 General requirements for Spill Prevention, Control, and Countermeasure Plans.

Subpart B—Requirements for Petroleum Oils and Non-Petroleum Oils, Except Animal Fats and Oils and Greases, and Fish and Marine Mammal Oils; and Vegetable Oils (Including Oils from Seeds, Nuts, Fruits, and Kernels)

112.8 Spill Prevention, Control, and Countermeasure Plan requirements for onshore facilities (excluding production facilities).
112.9 Spill Prevention, Control, and Countermeasure Plan Requirements for onshore oil production facilities (excluding drilling and workover facilities).
112.10 Spill Prevention, Control, and Countermeasure Plan requirements for onshore oil drilling and workover facilities.
112.11 Spill Prevention, Control, and Countermeasure Plan requirements for offshore oil drilling, production, or workover facilities.

Subpart C—Requirements for Animal Fats and Oils and Greases, and Fish and Marine Mammal Oils; and for Vegetable Oils, Including Oils from Seeds, Nuts, Fruits and Kernels

112.12 Spill Prevention, Control, and Countermeasure Plan requirements.
112.13–112.15 [Reserved]

Subpart D—Response Requirements

112.20 Facility response plans.
112.21 Facility response training and drills/exercises.
APPENDIX A TO PART 112—MEMORANDUM OF UNDERSTANDING BETWEEN THE SECRETARY

Law Judge, on his own motion, or at the request of any party, shall have the power to hold prehearing conferences, to issue subpoenas for the attendance and testimony of witnesses and the production of relevant papers, books, and documents, and he may administer oaths. The Regional Administrator, and any party submitting a request pursuant to § 108.3 or § 108.4, or counsel or other representative of such party or the Regional Administrator, may appear and offer evidence at the hearing.

§ 108.6 Recommendations.

At the conclusion of any hearing under this part, the Administrative Law Judge shall, based on the record, issue tentative findings of fact and recommendations concerning the alleged discrimination, and shall submit such tentative findings and recommendations to the Administrator. The Administrator shall adopt or modify the findings and recommendations of the Administrative Law Judge, and shall make copies of such findings and recommendations available to the complaining employee, the employer, and the public.

§ 108.7 Hearing before Administrator.

At his option, the Administrator may exercise any powers of an Administrative Law Judge with respect to hearings under this part.

PART 109—CRITERIA FOR STATE, LOCAL AND REGIONAL OIL REMOVAL CONTINGENCY PLANS

Sec.

109.1 Applicability.
109.2 Definitions.
109.3 Purpose and scope.
109.4 Relationship to Federal response actions.
109.5 Development and implementation criteria for State, local and regional oil removal contingency plans.
109.6 Coordination.

AUTHORITY: Sec. 11(j)(1)(B), 84 Stat. 96, 33 U.S.C. 1161(j)(1)(B).

SOURCE: 36 FR 22485, Nov. 25, 1971, unless otherwise noted.

§ 109.1 Applicability.

The criteria in this part are provided to assist State, local and regional agencies in the development of oil removal contingency plans for the inland navigable waters of the United States and all areas other than the high seas, coastal and contiguous zone waters, coastal and Great Lakes ports and harbors and such other areas as may be agreed upon between the Environmental Protection Agency and the Department of Transportation in accordance with section 11(j)(1)(B) of the Federal Act, Executive Order No. 11548 dated July 20, 1970 (35 FR 11677) and § 306.2 of the National Oil and Hazardous Materials Pollution Contingency Plan (35 FR 8511).

§ 109.2 Definitions.

As used in these guidelines, the following terms shall have the meaning indicated below:

(a) *Oil* means oil of any kind or in any form, including, but not limited to, petroleum, fuel oil, sludge, oil refuse, and oil mixed with wastes other than dredged spoil.

(b) *Discharge* includes, but is not limited to, any spilling, leaking, pumping, pouring, emitting, emptying, or dumping.

(c) *Remove* or *removal* refers to the removal of the oil from the water and shorelines or the taking of such other actions as may be necessary to minimize or mitigate damage to the public health or welfare, including, but not limited to, fish, shellfish, wildlife, and public and private property, shorelines, and beaches.

(d) *Major disaster* means any hurricane, tornado, storm, flood, high water, wind-driven water, tidal wave, earthquake, drought, fire, or other catastrophe in any part of the United States which, in the determination of the President, is or threatens to become of sufficient severity and magnitude to warrant disaster assistance by the Federal Government to supplement the efforts and available resources of States and local governments and relief organizations in alleviating the damage, loss, hardship, or suffering caused thereby.

(e) *United States* means the States, the District of Columbia, the Commonwealth of Puerto Rico, the Canal Zone, Guam, American Samoa, the Virgin Islands, and the Trust Territory of the Pacific Islands.

(f) *Federal Act* means the Federal Water Pollution Control Act, as amended, 33 U.S.C. 1151 *et seq.*

§ 109.3 Purpose and scope.

The guidelines in this part establish minimum criteria for the development and implementation of State, local, and regional contingency plans by State and local governments in consultation with private interests to insure timely, efficient, coordinated and effective action to minimize damage resulting from oil discharges. Such plans will be directed toward the protection of the public health or welfare of the United States, including, but not limited to, fish, shellfish, wildlife, and public and private property, shorelines, and beaches. The development and implementation of such plans shall be consistent with the National Oil and Hazardous Materials Pollution Contingency Plan. State, local and regional oil removal contingency plans shall provide for the coordination of the total response to an oil discharge so that contingency organizations established thereunder can function independently, in conjunction with each other, or in conjunction with the National and Regional Response Teams established by the National Oil and Hazardous Materials Pollution Contingency Plan.

§ 109.4 Relationship to Federal response actions.

The National Oil and Hazardous Materials Pollution Contingency Plan provides that the Federal on-scene commander shall investigate all reported spills. If such investigation shows that appropriate action is being taken by either the discharger or non-Federal entities, the Federal on-scene commander shall monitor and provide advice or assistance, as required. If appropriate containment or cleanup action is not being taken by the discharger or non-Federal entities, the Federal on-scene commander will take control of the response activity in accordance with section 11(c)(1) of the Federal Act.

§ 109.5 Development and implementation criteria for State, local and regional oil removal contingency plans.

Criteria for the development and implementation of State, local and regional oil removal contingency plans are:

(a) Definition of the authorities, responsibilities and duties of all persons, organizations or agencies which are to be involved or could be involved in planning or directing oil removal operations, with particular care to clearly define the authorities, responsibilities and duties of State and local governmental agencies to avoid unnecessary duplication of contingency planning activities and to minimize the potential for conflict and confusion that could be generated in an emergency situation as a result of such duplications.

(b) Establishment of notification procedures for the purpose of early detection and timely notification of an oil discharge including:

(1) The identification of critical water use areas to facilitate the reporting of and response to oil discharges.

(2) A current list of names, telephone numbers and addresses of the responsible persons and alternates on call to receive notification of an oil discharge as well as the names, telephone numbers and addresses of the organizations and agencies to be notified when an oil discharge is discovered.

(3) Provisions for access to a reliable communications system for timely notification of an oil discharge and incorporation in the communications system of the capability for interconnection with the communications systems established under related oil removal contingency plans, particularly State and National plans.

(4) An established, prearranged procedure for requesting assistance during a major disaster or when the situation exceeds the response capability of the State, local or regional authority.

(c) Provisions to assure that full resource capability is known and can be committed during an oil discharge situation including:

(1) The identification and inventory of applicable equipment, materials and supplies which are available locally and regionally.

(2) An estimate of the equipment, materials and supplies which would be required to remove the maximum oil discharge to be anticipated.

(3) Development of agreements and arrangements in advance of an oil discharge for the acquisition of equipment, materials and supplies to be used in responding to such a discharge.

(d) Provisions for well defined and specific actions to be taken after discovery and notification of an oil discharge including:

(1) Specification of an oil discharge response operating team consisting of trained, prepared and available operating personnel.

(2) Predesignation of a properly qualified oil discharge response coordinator who is charged with the responsibility and delegated commensurate authority for directing and coordinating response operations and who knows how to request assistance from Federal authorities operating under existing national and regional contingency plans.

(3) A preplanned location for an oil discharge response operations center and a reliable communications system for directing the coordinated overall response operations.

(4) Provisions for varying degrees of response effort depending on the severity of the oil discharge.

(5) Specification of the order of priority in which the various water uses are to be protected where more than one water use may be adversely affected as a result of an oil discharge and where response operations may not be adequate to protect all uses.

(e) Specific and well defined procedures to facilitate recovery of damages and enforcement measures as provided for by State and local statutes and ordinances.

§ 109.6 Coordination.

For the purposes of coordination, the contingency plans of State and local governments should be developed and implemented in consultation with private interests. A copy of any oil removal contingency plan developed by State and local governments should be forwarded to the Council on Environmental Quality upon request to facilitate the coordination of these contingency plans with the National Oil and Hazardous Materials Pollution Contingency Plan.

PART 110—DISCHARGE OF OIL

Sec.

110.1 Definitions.
110.2 Applicability.
110.3 Discharge of oil in such quantities as ''may be harmful'' pursuant to section 311(b)(4) of the Act.
110.4 Dispersants.
110.5 Discharges of oil not determined ''as may be harmful'' pursuant to section 311(b)(3) of the Act.
110.6 Notice.

AUTHORITY: 33 U.S.C. 1321(b)(3) and (b)(4) and 1361(a); E.O. 11735, 38 FR 21243, 3 CFR Parts 1971–1975 Comp., p. 793.

SOURCE: 52 FR 10719, Apr. 2, 1987, unless otherwise noted.

§ 110.1 Definitions.

Terms not defined in this section have the same meaning given by the Section 311 of the Act. As used in this part, the following terms shall have the meaning indicated below:

Act means the Federal Water Pollution Control Act, as amended, 33 U.S.C. 1251 *et seq.*, also known as the Clean Water Act;

Administrator means the Administrator of the Environmental Protection Agency (EPA);

Applicable water quality standards means State water quality standards adopted by the State pursuant to section 303 of the Act or promulgated by EPA pursuant to that section;

MARPOL 73/78 means the International Convention for the Prevention of Pollution from Ships, 1973, as modified by the Protocol of 1978 relating thereto, Annex I, which regulates pollution from oil and which entered into force on October 2, 1983;

Navigable waters means the waters of the United States, including the territorial seas. The term includes:

(a) All waters that are currently used, were used in the past, or may be susceptible to use in interstate or foreign commerce, including all waters

Appendix C: Summary of Revised Rule Provisions

The chart below summarizes rule amendments (beginning in 2002) to the SPCC regulation that was first promulgated in December 1973 and effective January 10, 1974. Each year that a rule citation was revised is marked with an "X". For specific details on amendments, please refer to preamble text and relevant sections of this guidance. In the table:

- 2002 refers to the amendments published at 67 FR 47042, July 17, 2002
- 2006 refers to the amendments published at 71 FR 77266, December 26, 2006
- 2008 refers to the amendments published at 73 FR 74236, December 5, 2008
- 2009 refers to the amendments published at 74 FR 58784, November 13, 2009
- 2011 EPA exempted milk and milk product containers-published at 76 FR 21652, April 18, 2011

Rule Provision	Description	2002	2006	2008	2009
Preamble Clarifications	Clarified that the definition of "mobile refueler" includes nurse tanks			x	
	Clarified definition of "permanently closed"			x	
	Clarified §112.8 versus §112.9 applicability			x	
	Clarified drilling and workover activities are not subject to §112.9			x	
	Clarified applicability of the rule to wind turbines			x	
	Clarified how manmade structures can affect rule applicability and how they can be considered to comply with rule requirements			x	
	Clarified applicability of loading/unloading requirements to transfers to/from exempt USTs			x	
	Clarified jurisdiction between EPA and the Department of Transportation (DOT)				x
§112.1(b)	Amended geographic scope of the rule	x			
§112.1(d)(2)(i), §112.1(d)(2)(ii)	Amended threshold requirements	x			
§112.1(d)(2)(i), §112.1(d)(4)	Exempted completely buried underground storage tanks (USTs) in 2002. Exempted underground emergency diesel generator tanks at nuclear power stations exempted in 2008. Amended exemption for underground emergency diesel generator tanks at nuclear power stations in 2009.	x		x	x
§112.1(d)(2)(i), §112.1(d)(11)	Exempted certain intra-facility gathering lines			x	
§112.1(d)(2)(ii), §112.1(d)(7)	Exempted motive power containers		x		

Rule Provision	Description	2002	2006	2008	2009
§112.1(d)(2)(ii), §112.1(d)(8)	Exempted hot-mix asphalt (HMA)			x	
§112.1(d)(2)(ii), §112.1(d)(9)	Exempted residential heating oil containers			x	
§112.1(d)(2)(ii), §112.1(d)(10)	Exempted pesticide application equipment and related mix containers			x	
§112.1(d)(2)(ii), §112.1(d)(12)	Exempted milk and milk product container and associated piping and appurtenances	**2011**			
§112.1(d)(5)	Established minimum container size	x			
§112.1(d)(6)	Exempted facilities or parts thereof used exclusively for wastewater treatment	x			
§112.1(f)	Established RA authority to determine applicability	x			

Rule Provision	Description	2002	2006	2008	2009
$112.2	Defined: Alteration Breakout tank Bulk storage container Bunkered tank Completely buried tank Contiguous zone Facility Partially buried tank Permanently closed Production facility Repair SPCC Plan Storage capacity Wetlands	x			
	Defined: Farm Mobile refueler Motive power container Oil-filled operational equipment		x		
	Defined: Loading/unloading rack Produced water container			x	
	Amended definition of “facility”			x	

Rule Provision	Description	2002	2006	2008	2009
	Amended definition of “production facility”			x	
§112.3(b)(2)	Amended timeframe for new production facilities to prepare and implement a plan			x	x
§112.3(d)	Amended Professional Engineer (PE) certification requirements	x	x	x	x
§112.3(e)(1)	Amended plan location requirements	x			
§112.3(g)(1)	Established Tier I qualified facilities eligibility criteria			x	
§112.3(g)(2)	Established Tier II qualified facilities eligibility criteria		x		
§112.4	Amended reportable discharge notification to EPA Regional Administrator (RA) requirements for SPCC facilities	x			
§112.5(b), §112.5(c)	Amended period of review of SPCC Plan and documentation requirements	x			
§112.6(a)	Established Tier I qualified facility requirements. Amended requirements in 2009.			x	x
§112.6(b)	Established Tier II qualified facility requirements. Amended requirements in 2008.		x	x	
§112.7	Established alternative SPCC Plan formats	x			
§112.7(a)	Eliminated spill history reporting requirements	x			
§112.7(a)(2)	Established environmental equivalence	x			
§112.7(a)(3)	Established facility diagram requirements in 2002. Amended requirements in 2008.	x		x	

Rule Provision	Description	2002	2006	2008	2009
§112.7(a)(3), §112.7(a)(4), §112.7(a)(5),	Established inclusion of information for use in a discharge requirements	x			
§112.7(c)	Amended general secondary containment requirements	x		x	
§112.7(d)	Established integrity testing requirements for impracticability claims	x			
§112.7(e), §112.8(c)(6)/ §112.12(c)(6)	Amended recordkeeping requirements for inspections and tests	x			
§112.7(f)	Amended personnel training requirements	x			
§112.7(g)	Amended facility security requirements			x	
§112.7(h)	Amended loading/unloading rack requirements			x	
§112.7(i)	Established brittle fracture evaluation requirements	x			
§112.7(k)	Established alternative to secondary containment requirements for qualified oil-filled operational equipment		x		
§112.8(c)(2), §112.8(c)(11), §112.12(c)(2), §112.12(c)(11)	Exempted mobile refuelers from sized secondary containment requirements in 2006. Sized secondary containment exemption extended to other non-transportation-related tank trucks in 2008.		x	x	
§112.8(c)(6), §112.12(c)(6)	Amended integrity testing requirements	x	x	x	

Rule Provision	Description	2002	2006	2008	2009
§112.8(d)(1), §112.12(d)(1)	Amended buried piping requirements	x			
§112.9(c)(2)	Amended secondary containment requirements for onshore production facilities	x			
§112.9(c)(5)	Established alternative to secondary containment requirements for flow-through process vessels			x	
§112.9(c)(6)	Established alternative to secondary containment requirements for produced water containers			x	
§112.9(d)(3)	Established alternative to secondary containment requirements for flowlines and intra-facility gathering lines			x	
§112.9(d)(4) [formerly §112.9(d)(3)]	Amended flowline and intra-facility gathering line maintenance program requirements	x		x	
§112.12(c)(6)	Established specific integrity testing requirements for Animal Fats and Vegetable Oils (AFVOs)			x	

Appendix D: Sample Bulk Storage Facility Plan

DISCLAIMER - APPENDIX D

The sample Spill Prevention, Control and Countermeasure (SPCC) Plan in Appendix D is intended to provide examples and illustrations of how a bulk storage facility could address a variety of scenarios in its SPCC Plan. The “facility” is not an actual facility, nor does it represent any actual facility or company. Rather, EPA is providing illustrative examples of the type and amount of information that is appropriate SPCC Plan language for these hypothetical situations.

Because the SPCC rule is designed to give each facility owner/operator the flexibility to tailor the facility’s SPCC Plan to the facility’s circumstances, this sample SPCC Plan is not a template to be adopted by a facility; doing so does not mean that the facility will be in compliance with the SPCC rule requirements. Nor is the sample plan a template that must be followed in order for the facility to be considered in compliance with the SPCC rule.

SPILL PREVENTION, CONTROL, AND COUNTERMEASURE PLAN

Unified Oil Company

123 A Street
Stonefield, Massachusetts 02000

May 12, 2003

Prepared by
Poppins & Associates, Inc.
Clearwater Falls, Massachusetts, 02210

Version 1.0, 11/28/2005

TABLE OF CONTENTS

	Page
Introduction	1
Part 1: Plan Administration	
1.1 Management Approval and Designated Person	3
1.2 Professional Engineer Certification	3
1.3 Location of SPCC Plan	4
1.4 Plan Review	4
1.5 Facilities, Procedures, Methods, or Equipment Not Yet Fully Operational	5
1.6 Cross-Reference with SPCC Provisions	5
Part 2: General Facility Information	
2.1 Facility Description	8
2.2 Evaluation of Discharge Potential	11
Part 3: Discharge Prevention – General SPCC Provisions	
3.1 Compliance with Applicable Requirements	12
3.2 Facility Layout Diagram	12
3.3 Spill Reporting	12
3.4 Potential Discharge Volumes and Direction of Flow	13
3.5 Containment and Diversionary Structures	14
3.6 Practicability of Secondary Containment	16
3.7 Inspections, Tests, and Records	16
3.8 Personnel, Training, and Discharge Prevention Procedures	18
3.9 Security	19
3.10 Tank Truck Loading/Unloading Rack Requirements	19
3.11 Brittle Fracture Evaluation	22
3.12 Conformance with State and Local Applicable Requirements	22
Part 4: Discharge Prevention – SPCC Provisions for Onshore Facilities (Excluding Production Facilities)	
4.1 Facility Drainage	23
4.2 Bulk Storage Containers	23
4.3 Transfer Operations, Pumping, and In-Plant Processes	29

Part 5: Discharge Response

5.1 Response to a Minor Discharge 30
5.2 Response to a Major Discharge 31
5.3 Waste Disposal 32
5.4 Discharge Notification 32
5.5 Cleanup Contractors and Equipment Suppliers 33

List of Tables

Table 1-1: Plan Review Log 6
Table 1-2: SPCC Cross-Reference 7
Table 2-1: Oil Containers 9
Table 2-2: Oil Discharge History 10
Table 3-1: Potential Discharge Volume and Direction of Flow 13
Table 3-2: Inspection and Testing Program 16
Table 3-3: Fuel Transfer Procedures 21
Table 4-1: List of Oil Containers 24
Table 4-2: Scope and Frequency of Bulk Storage Containers Inspections and Tests 27

Appendices

A: Site Plan and Facility Diagram
B: Substantial Harm Determination
C: Facility Inspection Checklists
D: Record of Containment Dike Drainage
E: Record of Discharge Prevention Briefings and Training
F: Calculation of Secondary Containment Capacity
G: Records of Tank Integrity and Pressure Tests
H: Emergency Contacts
I: Discharge Notification Form
J: Discharge Response Equipment Inventory
K: Agency Notification Standard Report

LIST OF ACRONYMS AND ABBREVIATIONS

AST	Aboveground Storage Tank
EPA	U.S. Environmental Protection Agency
MADEP	Massachusetts Department of Environmental Protection
NPDES	National Pollutant Discharge Elimination System
PE	Professional Engineer
POTW	Publicly Owned Treatment Works
SPCC	Spill Prevention, Control, and Countermeasure
STI	Steel Tank Institute
UST	Underground Storage Tank

INTRODUCTION

Purpose

The purpose of this Spill Prevention, Control, and Countermeasure (SPCC) Plan is to describe measures implemented by Unified Oil to prevent oil discharges from occurring, and to prepare Unified Oil to respond in a safe, effective, and timely manner to mitigate the impacts of a discharge.

This Plan has been prepared to meet the requirements of Title 40, *Code of Federal Regulations,* Part 112 (40 CFR part 112), and supercedes the earlier Plan developed to meet provisions in effect since 1974.

In addition to fulfilling requirements of 40 CFR part 112, this SPCC Plan is used as a reference for oil storage information and testing records, as a tool to communicate practices on preventing and responding to discharges with employees, as a guide to facility inspections, and as a resource during emergency response.

Unified Oil management has determined that this facility does not pose a risk of substantial harm under 40 CFR part 112, as recorded in the “Substantial Harm Determination” included in Appendix B of this Plan.

This Plan provides guidance on key actions that Unified Oil must perform to comply with the SPCC rule:

- ❑ Complete monthly and annual site inspections as outlined in the Inspection, Tests, and Records section of this Plan (Section 3.7) using the inspection checklists included in Appendix C.
- ❑ Perform preventive maintenance of equipment, secondary containment systems, and discharge prevention systems described in this Plan as needed to keep them in proper operating conditions.
- ❑ Conduct annual employee training as outlined in the Personnel, Training, and Spill Prevention Procedures section of this Plan (Section 3.8) and document them on the log included in Appendix E.
- ❑ If either of the following occurs, submit the SPCC Plan to the EPA Region 1 Regional Administrator (RA) and the Massachusetts Department of Environmental Protection (MADEP), along with other information as detailed in Section 5.4 of this Plan:
    - ❑ The facility discharges more than 1,000 gallons of oil into or upon the navigable waters of the U.S. or adjoining shorelines in a single spill event; or

- ❑ The facility discharges oil in quantity greater than 42 gallons in each of two spill events within any 12-month period.

- ❑ Review the SPCC Plan at least once every five (5) years and amend it to include more effective prevention and control technology, if such technology will significantly reduce the likelihood of a spill event and has been proven effective in the field at the time of the review. Plan amendments, other than administrative changes discussed above, must be recertified by a Professional Engineer on the certification page in Section 1.2 of this Plan.

- ❑ Amend the SPCC Plan within six (6) months whenever where is a change in facility design, construction, operation, or maintenance that materially affects the facility's spill potential. The revised Plan must be recertified by a Professional Engineer (PE).

- ❑ Review the Plan on an annual basis. Update the Plan to reflect any "administrative changes" that are applicable, such as personnel changes or revisions to contact information, such as phone numbers. Administrative changes must be documented in the Plan review log of Section 1.4 of this Plan, but do not have to be certified by a PE.

Part 1: Plan Administration

1.1 Management Approval and Designated Person (40 CFR 112.7)

Unified Oil Company ("Unified Oil') is committed to preventing discharges of oil to navigable waters and the environment, and to maintaining the highest standards for spill prevention control and countermeasures through the implementation and regular review and amendment to the Plan. This SPCC Plan has the full approval of Unified Oil management. Unified Oil has committed the necessary resources to implement the measures described in this Plan.

The Facility Manager is the Designated Person Accountable for Oil Spill Prevention at the facility and has the authority to commit the necessary resources to implement this Plan.

Authorized Facility Representative (facility response coordinator): Susan Blake

Signature:	Susan Blake
Title:	Facility Manager
Date:	May 12, 2003

1.2 Professional Engineer Certification (40 CFR 112.3(d))

The undersigned Registered Professional Engineer is familiar with the requirements of Part 112 of Title 40 of the *Code of Federal Regulations* (40 CFR part 112) and has visited and examined the facility, or has supervised examination of the facility by appropriately qualified personnel. The undersigned Registered Professional Engineer attests that this Spill Prevention, Control, and Countermeasure Plan has been prepared in accordance with good engineering practice, including consideration of applicable industry standards and the requirements of 40 CFR part 112; that procedures for required inspections and testing have been established; and that this Plan is adequate for the facility. [40 CFR 112.3(d)]

This certification in no way relieves the owner or operator of the facility of his/her duty to prepare and fully implement this SPCC Plan in accordance with the requirements of 40 CFR part 112. This Plan is valid only to the extent that the facility owner or operator maintains, tests, and inspects equipment, containment, and other devices as prescribed in this Plan.

Julie Andrews Signature	90535055, Massachusetts Professional Engineer Registration Number
Julie Andrews Name	*Sr. Process Engineer* Title
Poppins and Associates Company	*May 12, 2003* Date

PE Seal
MA
Julie Andrews
#90535055

1.3 Location of SPCC Plan (40 CFR 112.3(e))

In accordance with 40 CFR 112.3(e), a complete copy of this SPCC Plan is maintained at the facility in the office building. The front office is attended whenever the facility is operating, i.e., 7:00 AM to 5:00 PM, 6 days per week (closed on Sundays).

1.4 Plan Review (40 CFR 112.3 and 112.5)

1.4.1 Changes in Facility Configuration

In accordance with 40 CFR 112.5(a), Unified Oil periodically reviews and evaluates this SPCC Plan for any change in the facility design, construction, operation, or maintenance that materially affects the facility's potential for an oil discharge, including, but not limited to:

- commissioning of containers;
- reconstruction, replacement, or installation of piping systems;
- construction or demolition that might alter secondary containment structures; or
- changes of product or service, revisions to standard operation, modification of testing/inspection procedures, and use of new or modified industry standards or maintenance procedures.

Amendments to the Plan made to address changes of this nature are referred to as technical amendments, and must be certified by a PE. Non-technical amendments can be done (and must be documented in this section) by the facility owner and/or operator. Non-technical amendments include the following:

- change in the name or contact information (i.e., telephone numbers) of individuals responsible for the implementation of this Plan; or
- change in the name or contact information of spill response or cleanup contractors.

Unified Oil must make the needed revisions to the SPCC Plan as soon as possible, but no later than six months after the change occurs. The Plan must be implemented as soon as possible following any technical amendment, but *no later than six months* from the date of the amendment. The Facility Manager is responsible for initiating and coordinating revisions to the SPCC Plan.

1.4.2 Scheduled Plan Reviews

In accordance with 40 CFR 112.5(b), Unified Oil reviews this SPCC Plan at least once every five years (in the past, such reviews were required every three years). Revisions to the Plan, if needed, are made within six months of the five-year review. A registered Professional Engineer certifies any technical amendment to the Plan, as described above, in accordance with 40 CFR 112.3(d). The last SPCC review occurred on *May 13, 2001*. This Plan is dated *May 12, 2003*. The next plan review is therefore scheduled to take place on or prior to *May 12, 2008*.

1.4.3 Record of Plan Reviews

Scheduled reviews and Plan amendments are recorded in the Plan Review Log (Table 1-1). This log must be completed even if no amendment is made to the Plan as a result of the review. Unless a technical or administrative change prompts an earlier review of the Plan, the next scheduled review of this Plan must occur by *May 12, 2008.*

1.5 Facilities, Procedures, Methods, or Equipment Not Yet Fully Operational (40 CFR 112.7)

Bulk storage containers at this facility have never been tested for integrity since their installation in 1989. Section 4.2.6 of this Plan describes the inspection program to be implemented by the facility following a regular schedule, including the dates by which each of the bulk storage containers must be tested.

1.6 Cross-Reference with SPCC Provisions (40 CFR 112.7)

This SPCC Plan does not follow the exact order presented in 40 CFR part 112. Section headings identify, where appropriate, the relevant section(s) of the SPCC rule. Table 1-2 presents a cross-reference of Plan sections relative to applicable parts of 40 CFR part 112.

Table 1-1: Plan Review Log

By	Date	Activity	PE certification required?	Comments
Mike Davies	5/20/1989	Prepare Plan Start of Operations	Yes	Initial SPCC Plan.
Mike Davies	5/18/1992	Scheduled review	No	No change.
Mike Davies	2/18/1994	Plan amendment	Yes*	Changes to inspection procedures, addition of a new tank, full review not conducted.
Susan Blake	5/15/1995	Scheduled review	No	Change in responsible individual and contact information.
Susan Blake	5/15/1998	Scheduled review	No	No change.
Susan Blake	5/13/2001	Scheduled review	No	No change.
Susan Blake	5/12/2003	Periodic review due to physical change	Yes*	Installation of oil/water separator

* Previous PE certifications of this Plan are summarized below.

Date	Scope	PE Name	Licensing State and Registration No.
2/18/1994	Addition of new tank and changes in inspection procedures.	Chris Ebert	MA, 90117823
5/12/2003	Installation of oil/water separator	Julie Andrews	MA, 905350055

Table 1-2: SPCC Cross-Reference

Provision	Plan Section	Page
112.3(d)	Professional Engineer Certification	3
112.3(e)	Location of SPCC Plan	4
112.5	Plan Review	4 Table 1-1
112.7	Management Approval	3
112.7	Cross-Reference with SPCC Rule	Table 1-2
112.7(a)(3)	Part 2: General Facility Information Appendix A: Site Plan and Facility Diagram	8 Appendix A
112.7(a)(4)	5.4 Discharge Notification	32 Appendix I Appendix K
112.7(a)(5)	Part 5: Discharge Response	32
112.7(b)	3.4 Potential Discharge Volumes and Direction of Flow	13
112.7(c)	3.5 Containment and Diversionary Structures	14
112.7(d)	3.6 Practicability of Secondary Containment	16
112.7(e)	3.7 Inspections, Tests, and Records	16 Appendix B
112.7(f)	3.8 Personnel, Training and Discharge Prevention Procedures	18
112.7(g)	3.9 Security	19
112.7(h)	3.10 Tank Truck Loading/Unloading	19
112.7(i)	3.11 Brittle Fracture Evaluation	22
112.7(j)	3.12 Conformance with Applicable State and Local Requirements	22
112.8(b)	4.1 Facility Drainage	23
112.8(c)(1)	4.2.1 Construction	23
112.8(c)(2)	4.2.2 Secondary Containment	25
112.8(c)(3)	4.2.3 Drainage of Diked Areas	26 Appendix D
112.8(c)(4)	4.2.4 Corrosion Protection	26
112.8(c)(5)	4.2.5 Partially Buried and Bunkered Storage Tanks	26
112.8(c)(6)	4.2.6 Inspection Appendix B - Facility Inspection Checklists	26 Appendix C
112.8(c)(7)	4.2.7 Heating Coils	27
112.8(c)(8)	4.2.8 Overfill Prevention System	27
112.8(c)(9)	4.2.9 Effluent Treatment Facilities	28
112.8(c)(10)	4.2.10 Visible Discharges	28
112.8(c)(11)	4.2.11 Mobile and Portable Containers	28
112.8(d)	4.3 Transfer Operations, Pumping and In-Plant Processes	29
112.20(e)	Certification of Substantial Harm Determination	Appendix B

* Only selected excerpts of relevant rule text are provided. For a complete list of SPCC requirements, refer to the full text of 40 CFR part 112.

Part 2: General Facility Information

Name:	Unified Oil Company
Address:	123 A Street Stonefield, MA 02000 (781) 555-5556
Type:	Bulk storage distribution facility
Date of Initial Operations:	May 20, 1989
Owner/Operator:	Blake and Daughters, Inc. 20 Fairview Road Stonefield, MA 02000
Primary contact:	Susan Blake, Facility Manager Work: (781) 555-5550 Cell (24 hours): (781) 555-5559

2.1 Facility Description (40 CFR 112.7(a)(3))

2.1.1 Location and Activities

Unified Oil distributes a variety of petroleum products to primarily commercial customers. The facility handles, stores, uses, and distributes petroleum products in the form of gasoline, diesel, No. 2 fuel oil, No. 6 fuel oil, and motor oil. Unified Oil receives products by common carrier via tanker truck. The products are stored in several aboveground storage tanks (ASTs) and in one underground storage tank (UST). They are delivered to customers by Unified Oil trucks or by independent contractors. The facility refuels its own two delivery trucks from an underground diesel tank connected to a fueling pump.

Hours of operation are between 7:00 AM and 5:00 PM, 6 days per week. Personnel at the facility include a facility manager, a plant operator, two truck drivers, an office administrator, and three operations and maintenance personnel.

The Site Plan and Facility Diagram included in Appendix A of this Plan show the location and layout of the facility. The Facility Diagram (Figure A-2) shows the location of oil containers, buildings, loading/unloading and transfer areas, and critical spill control structures.

Unified Oil is located in a primarily commercial area at 123 A Street in Stonefield, Massachusetts. The site is comprised of approximately 2 acres of land and is bordered to the east by A Street, to the west by Silver Creek, and to the north by ABC Plating Co.

The site includes an office building, a maintenance shop, a tanker truck loading rack and unloading area, and product storage and handling areas. Petroleum products are stored within the main bulk storage area, underground, and inside the maintenance building.

2.1.2 Oil Storage

Oil storage at the facility consists of seven tanks: four fixed ASTs, one portable tank, and two metallic USTs. In addition, the facility stores a varying stock of oil drums inside the maintenance building.

The capacities of oil containers present at the site are listed below and are also indicated on the facility diagram in Figure A-2. All containers with capacity of 55 gallons or more are included. The capacity of the oil/water separator is not included in the total storage capacity for the facility since it is used to treat storm water and as a means of secondary containment for areas of the facility with potential for an oil discharge outside dikes or berms.

Unified Oil owns two 2,000-gallon transport trucks that are used to deliver product to customers. One of the two trucks is periodically parked overnight while full; the capacity of this truck is therefore counted in the total storage capacity for this facility.

Table 2-1: Oil Containers

ID	Storage capacity	Content	Description
Fixed Storage			
1	20,000 gallons	Diesel	Aboveground vertical tank
2	20,000 gallons	Unleaded regular gasoline	Aboveground horizontal tank elevated on built-in saddles
3	20,000 gallons	Unleaded premium gasoline	Aboveground horizontal tank elevated on built-in saddles
6	1,000 gallons	No. 2 fuel oil	Underground horizontal tank
7	10,000 gallons	No. 6 fuel oil	Field-constructed aboveground vertical tank
	1,100 gallons	Motor oil	55-gallon storage drums (variable stock; up to 20 drums on site at any time)
Portable storage			
4	500 gallons	Gasoline	Double-walled aboveground horizontal tank
Vehicles			
	2,000 gallons	Fuel oil	Delivery truck*

* ***Note:*** *Unified Oil owns two delivery trucks. Both trucks are used in transportation-related activities outside the confines of the facility and generally return to the facility*

empty for parking overnight. One of the two delivery trucks is periodically parked while full. This truck is therefore counted in the storage capacity for this facility. The other truck is dedicated to scheduled deliveries and returns to the facility empty (except for minor residual). If the tanker truck returns to the facility with more than residual product, this product will be returned to inventory via the unloading station. If the facility decides to use this tanker for overnight storage, then this Plan must be modified to include the capacity of the truck and ensure compliance with other rule requirements, including secondary containment.

Total Oil Storage:	**74,600 gallons**

Other containers: (1) 1,500-gallon oil/water separator

Note: The oil/water separator is used treat facility drainage (i.e., wastewater) prior to discharge into Silver Creek under state and federal wastewater discharge permits. Discharge from the facility includes storm water collected from the paved areas outside the loading rack/unloading area containment berm and bulk storage containment dike. No external oil tanks are associated with the oil/water separator. This equipment is used to meet certain secondary containment requirements under 40 CFR part 112, as described later in this Plan. Thus, the capacity of the oil/water separator is not counted towards the facility total storage capacity.

(1) 5,000-gallon underground horizontal tank (Diesel) – Tank #5

Note: This underground storage tank is subject to, and meets, all the technical requirements of Massachusetts Underground Storage Tank Program at 527 CMR 9, as approved under 40 CFR part 281, and is therefore not counted in the storage capacity for this facility (exempted under 40 CFR 112.1(d)(4). Its location is indicated on the Facility Diagram in Appendix A. Note that the other underground storage tank (Tank #6) which contains No. 2 fuel oil for heating consumption on the premises of the facility is not subject to certain technical requirements under 40 CFR part 280 or a program approved under part 281, in particular corrosion protection, and is therefore included in the storage capacity for this facility (and is SPCC-regulated), as described above.

2.2 Evaluation of Discharge Potential

2.2.1 Distance to Navigable Waters and Adjoining Shorelines and Flow Paths

The facility is located on relatively level terrain. Drainage generally flows in the direction of Silver Creek, which runs immediately along the southwest side of the site. Silver Creek flows north to the Blackpool River approximately 1.5 miles from the facility. Spill trajectories are indicated on the facility diagram. Storm drains are located along A Street at the northeast end of the site. They discharge to Silver Creek.

Approximately three-quarters of the facility's ground surface area is paved with asphalt. The remainder consists of compacted gravel, grass, and low-lying vegetation.

2.2.2 Discharge History

Table 2-1 summarizes the facility's discharge history.

Table 2-2: Oil Discharge History

Description of Discharge	Corrective Actions Taken	Plan for Preventing Recurrence
On 3/23/2003, a leaking valve on a delivery truck discharged 50 gallons of diesel oil onto the ground during a rain event, allowing approximately 10 gallons to enter Silver Creek.	A boom was placed into Silver Creek immediately upon discovery. Approximately 35 gallons of oil were recovered from Silver creek and the facility ground.	An oil/water separator was installed and the facility drainage was designed to flow into the separator.

PART 3: Discharge Prevention - General SPCC Provisions

The following measures are implemented to prevent oil discharges during the handling, use, or transfer of oil products at the facility. Oil-handling employees have received training in the proper implementation of these measures.

3.1 Compliance with Applicable Requirements (40 CFR 112.7(a)(2))

This facility uses an oil/water separator as part of its drainage system to contain oil discharged in certain areas of the facility (i.e., overfills, and the loading/unloading area associated with Tank #4). Because Tank #4 does not meet the specifications provided in EPA's memorandum concerning its policy on double-walled tanks, general containment must be provided to address overfills. The separator provides environmental protection equivalent to the requirements under 112.8(b)(3) to use ponds, lagoons, or catchment basins to retain oil at the facility in the event of an uncontrolled discharge. As described in Section 3.5 of this Plan, the operational and emergency oil storage capacity of the oil/water separator is sufficient to handle the quantity of oil expected to be discharged in undiked areas from tank overfills or transfer operations.

Non-destructive integrity evaluation is not performed on Tank #4 (500-gallon portable storage tank) or the 55-gallon storage drums. Tank #4 has a double-wall construction and is elevated off the ground. The tank is inspected regularly and following a regular schedule in accordance with the Steel Tank Institute (STI) SP-001 tank inspection standard as described in this Plan. Any leakage from the primary container would be detected through monitoring of the interstitial space performed on a monthly basis. Any leakage from the secondary shell would be detected visually during scheduled visual inspections by facility personnel. Storage drums are elevated on spill pallets and have all sides visible, and any leak would be readily detected by facility personnel before they can cause a discharge to navigable waters or adjoining shorelines. Corrosion poses minimal risk of failure since drums are single-use and remain on site for a relatively short period of time (less than one year). The drum storage area is inspected monthly. This is in accordance with accepted industry practice for drum storage and provides an effective means of verifying container integrity, as noted by EPA in the preamble to the SPCC rule at 67 FR 47120.

3.2 Facility Layout Diagram (40 CFR 112.7(a)(3))

Figure A-1 in Appendix A shows the general location of the facility on a U.S. Geological Survey topographic map. Figure A-2 in Appendix A presents a layout of the facility and the location of storage tanks and drums. The diagram also shows the location of storm water drain inlets and the direction of surface water runoff. As required under 40 CFR 112.7(a)(3), the facility diagram indicates the location and content of ASTs, USTs, and transfer stations and connecting piping.

3.3 Spill Reporting (40 CFR 112.7(a)(4))

The discharge notification form included in Appendix I will be completed upon immediate detection of a discharge and prior to reporting a spill to the proper notification contacts.

3.4 Potential Discharge Volumes and Direction of Flow (40 CFR 112.7(b))

Table 3-1 presents expected volume, discharge rate, general direction of flow in the event of equipment failure, and means of secondary containment for different parts of the facility where oil is stored, used, or handled.

Table 3-1: Potential Discharge Volumes and Direction of Flow

Potential Event	Maximum volume released (gallons)	Maximum discharge rate	Direction of Flow	Secondary Containment
Bulk Storage Area (Aboveground Storage Tanks #1, 2, 3, or 7)				
Failure of aboveground tank (collapse or puncture below product level)	20,000	Gradual to instantaneous	SW to Silver Creek	Concrete dike
Tank overfill	1 to 120	60 gal/min	SW to Silver Creek	Concrete dike
Pipe failure	20,000	240 gal/min	SW to Silver Creek	Concrete dike
Leaking pipe or valve packing	600	1 gal/min	SW to Silver Creek	Concrete dike
Leaking heating coil (Tank #7)	10,000	1 gal/min	SW to Silver Creek	Concrete dike
Loading Rack/Unloading Area				
Tank truck leak or failure inside the rollover berm	1 to 2,000	Gradual to instantaneous	SW to Silver Creek	Rollover berm, on to oil/water separator
Tank truck leak or failure outside the rollover berm	1 to 2,000	Gradual to instantaneous	SW to Silver Creek	Rollover berm, on to oil/water separator
Hose leak during truck loading	1 to 300	60 gal/min	SW to Silver Creek	Rollover berm
Fuel Dispensing Areas				
Tank #4 and diesel dispenser hose/ connections leak	1 to 150	30 gal/minute	SW to Silver Creek.	Land-based spill response capability (spill kit) and oil/water separator
Maintenance Building				
Leak or failure of drum	1 to 55	Gradual to instantaneous	SW to Silver Creek.	Spill pallets, oil/water separator
Other Areas				
Complete failure of portable tank (Tank #4)	500	Gradual to instantaneous	SW to Silver Creek.	Secondary shell, oil/water separator
Leaking portable tank or overfills (Tank #4)	1 to 100	3 gal/min	SW to Silver Creek.	Secondary shell, oil/water separator

Potential Event	Maximum volume released (gallons)	Maximum discharge rate	Direction of Flow	Secondary Containment
Leak during transfer to heating fuel UST (Tank # 6)	1 to 120	60 gal/min	SW to Silver Creek.	Oil/water separator
Oil/water separator malfunction	1 to 300	1 gal/min	SW to Silver Creek.	

3.5 Containment and Diversionary Structures (40 CFR 112.7(c))

Methods of secondary containment at this facility include a combination of structures (e.g., dike, berm, built-in secondary containment), drainage systems (e.g., oil/water separator), and land-based spill response (e.g., drain covers, sorbents) to prevent oil from reaching navigable waters and adjoining shorelines:

- For bulk storage containers (refer to Section 4.2.2 of this Plan):
    - **Dike.** A concrete dike enclosure is provided around fixed aboveground storage tanks, as described in Section 4.2.2 of this Plan.
    - **Double-wall tank construction.** Tank #6 (UST), and the 500-gallon portable storage tank (Tank #4) both have double-wall design with a secondary shell designed to contain 110 percent of the inner shell capacity. The portable tank is generally located near the entrance to the maintenance building; however, it may be used elsewhere on site. It is used to refuel various small pieces of equipment (each less than 55-gallon capacity) such as trucks and compressors, that may be deployed at different areas on the site.
    - **Spill pallets.** Each spill pallet has a capacity of 75 gallons, which can effectively contain the volume of any single 55-gallon drum. Drums are also stored inside the maintenance building and are not exposed to precipitation. The floor of the maintenance building and lower 24 inches of the outside walls are constructed of poured concrete that would restrict the flow of oil outside the building. The floor has two floor drains; the drain closest to the drum storage area is located 18 feet away. Floor drains flow into the oil/water separator, which is capable of containing any oil discharged from a 55-gallon drum.
- At the loading rack and unloading area (refer to Section 3.10 of this Plan):
    - **Rollover berm.** The loading rack/unloading area is surrounded by a 4-inch rollover berm that provides sufficient containment for the largest compartment of the tank truck loading or unloading at the facility (2,000 gallons), and an additional 4 inches of freeboard for precipitation.

- In transfer areas and other parts of the facility where a discharge could occur:

  - **Drip pans.** Fill ports for all ASTs are equipped with drip pans to contain small leaks from the piping/hose connections.

  - **Sorbent material.** Spill cleanup kits that include absorbent material, booms, and other portable barriers are located inside the maintenance building near the drummed oil storage area and in an outside shed located near the loading rack/unloading area, as shown on the Facility Diagram in Appendix A. The spill kits are located within close proximity of the oil product storage and handling areas for rapid deployment should a spill occur. Sorbent material, booms, and other portable barriers are stored in the shed next to the loading rack/unloading area to allow for quick deployment in the event of a discharge during loading/unloading activities or any other accidental discharge outside the dike or loading rack/unloading area, such as from tank vehicles entering/leaving the facility or spills associated with the fuel dispenser. The response equipment inventory for the facility is listed in Appendix J of this Plan. The inventory is checked monthly to ensure that used material is replenished.

  - **Drainage system.** The facility surface drainage is engineered to direct oil that may be discharged outside of engineered containment structures such as dikes or berms into the oil/water separator.

  - **Oil/water separator.** The oil/water separator is designed to separate and retain oil at the facility. The oil/water separator has a total capacity for oil/water mixture of 1,500 gallons and a design flow rate of 150 gallons per minute. The separator outlet valve can be closed in the event of a large discharge (greater than 300 gallons) to provide additional emergency containment of up to 1,200 gallons. The maximum amount of oil potentially discharged outside the diked or bermed areas is estimated at roughly 2,000 gallons (from the complete failure of an on-site tanker truck). A spill of this volume outside the diked or bermed areas will be primarily contained by deploying sorbent material and other portable spill barriers upon discovery of the spill, and additional oil containment capacity will be provided by the oil/water separator. The operating oil storage capacity is 300 gallons. Best Management Practices are used to minimize the amount of solids and oil that flow into the oil/water separator. Facility personnel are instructed to avoid and address small spills using sorbents to minimize runoff of oil into the oil/water separator. The oil/water separator is inspected monthly as part of the scheduled inspection to check the level of water within the separator and measure the depth of bottom sludges and floating oils. Floating oil is removed by a licensed waste collector when it reaches a thickness of 2 inches.

3.6 Practicability of Secondary Containment (40 CFR 112.7(d))

Unified Oil management has determined that secondary containment is practicable at this facility.

3.7 Inspections, Tests, and Records (40 CFR 112.7(e))

As required by the SPCC rule, Unified Oil performs the inspections, tests, and evaluations listed in the following table. Table 3-2 summarizes the various types of inspections and tests performed at the facility. The inspections and tests are described later in this section, and in the respective sections that describe different parts of the facility (e.g., Section 4.2.6 for bulk storage containers).

Table 3-2: Inspection and Testing Program

Facility Component	Action	Frequency/Circumstances
Aboveground container	Test container integrity. Combine visual inspection with another testing technique (non-destructive shell testing). Inspect outside of container for signs of deterioration and discharges.	Following a regular schedule (monthly, annual, and during scheduled inspections) and whenever material repairs are made.
Container supports and foundation	Inspect container's supports and foundations.	Following a regular schedule (monthly, annual, and during scheduled inspections) and whenever material repairs are made.
Liquid level sensing devices (overfill)	Test for proper operation.	Monthly
Diked area	Inspect for signs of deterioration, discharges, or accumulation of oil inside diked areas.	Monthly
	Visually inspect content for presence of oil.	Prior to draining
Lowermost drain and all outlets of tank truck	Visually inspect.	Prior to filling and departure
Effluent treatment facilities	Detect possible system upsets that could cause a discharge.	Daily, monthly
All aboveground valves, piping, and appurtenances	Assess general condition of items, such as flange joints, expansion joints, valve glands and bodies, catch pans, pipeline supports, locking of valves, and metal surfaces.	Monthly

Facility Component	Action	Frequency/Circumstances
Buried metallic storage tank	Leak test.	Annually
Buried piping	Inspect for deterioration.	Whenever a section of buried line is exposed for any reason.
	Integrity and leak testing.	At the time of installation, modification, construction, relocation, or replacement.

3.7.1 Daily Inspection

A Unified Oil employee performs a complete walk-through of the facility each day. This daily visual inspection involves: (1) looking for tank/piping damage or leakage, stained or discolored soils, or excessive accumulation of water in diked and bermed areas; (2) observing the effluent from the oil/water separator; and (3) verifying that the dike drain valve is securely closed.

3.7.2 Monthly Inspection

The checklist provided in Appendix C is used for monthly inspections by Unified Oil personnel. The monthly inspections cover the following key elements:

- ❑ Observing the exterior of aboveground storage tanks, pipes, and other equipment for signs of deterioration, leaks, corrosion, and thinning.
- ❑ Observing the exterior of portable containers for signs of deterioration or leaks.
- ❑ Observing tank foundations and supports for signs of instability or excessive settlement.
- ❑ Observing the tank fill and discharge pipes for signs of poor connection that could cause a discharge, and tank vent for obstructions and proper operation.
- ❑ Verifying the proper functioning of overfill prevention systems.
- ❑ Checking the inventory of discharge response equipment and restocking as needed.
- ❑ Observing the effluent and measuring the quantity of accumulated oil within the oil/water separator.

All problems regarding tanks, piping, containment, or response equipment must immediately be reported to the Facility Manager. Visible oil leaks from tank walls, piping, or other components must be repaired as soon as possible to prevent a larger spill or a discharge to navigable waters or adjoining shorelines. Pooled oil is removed immediately upon discovery.

Written monthly inspection records are signed by the Facility Manager and maintained with this SPCC Plan for a period of three years.

3.7.3 Annual Inspection

Facility personnel perform a more thorough inspection of facility equipment on an annual basis. This annual inspection complements the monthly inspection described above and is performed in June of each year using the checklist provided in Appendix C of this Plan.

The annual inspection is preferably performed after a large storm event in order to verify the imperviousness and/or proper functioning of drainage control systems such as the dike, rollover berm, control valves, and the oil/water separator.

Written annual inspection records are signed by the Facility Manager and maintained with this SPCC Plan for a period of three years.

3.7.4 Periodic Integrity Testing

In addition to the above monthly and annual inspections by facility personnel, Tanks #1, 2, 3, 4, and 7 are periodically evaluated by an outside certified tank inspector following the Steel Tank Institute (STI) *Standard for the Inspection of Aboveground Storage Tanks*, SP-001, 2005 version, as described in Section 4.2.6 of this Plan.

3.8 Personnel, Training, and Discharge Prevention Procedures (40 CFR 112.7(f))

The Facility Manager is the facility designee and is responsible for oil discharge prevention, control, and response preparedness activities at this facility.

Unified Oil management has instructed oil-handling facility personnel in the operation and maintenance of oil pollution prevention equipment, discharge procedure protocols, applicable pollution control laws, rules and regulations, general facility operations, and the content of this SPCC Plan. Any new facility personnel with oil-handling responsibilities are provided with this same training prior to being involved in any oil operation.

Annual discharge prevention briefings are held by the Facility Manager for all facility personnel involved in oil operations. The briefings are aimed at ensuring continued understanding and adherence to the discharge prevention procedures presented in the SPCC Plan. The briefings also highlight and describe known discharge events or failures, malfunctioning components, and recently implemented precautionary measures and best practices. Facility operators and other personnel will have the opportunity during the briefings to share recommendations concerning health, safety, and environmental issues encountered during facility operations.

A simulation of an on-site vehicular discharge has been conducted, and future training exercises will be periodically held to prepare for possible discharge responses.

Records of the briefings and discharge prevention training are kept on the form shown in Appendix E and maintained with this SPCC Plan for a period of three years.

3.9 Security (40 CFR 112.7(g))

The facility is surrounded by 8-ft tall steel security fencing. The fence encircles the entire footprint of the facility. The single entrance gate is locked when the facility is unattended.

All drain valves for containment areas are locked in the closed position to prevent unauthorized opening. Water draw valves on the 20,000-gallon storage tanks are maintained in the closed position to prevent unauthorized opening via locks. Keys for all locked valves are kept in the front office.

Two area lights illuminate the loading/unloading and storage areas. Additional motion-activated lights are placed in other areas of the facility. The lights are placed to allow for the discovery of discharges and to deter acts of vandalism.

The electrical starter controls for the oil pumps, including the fuel dispenser, are located in a closet inside the maintenance shop. The closet is locked when the pumps are not in use. The maintenance shop is locked when the facility is unattended.

The facility securely caps or blank-flanges the loading/unloading connections of facility piping when not in service or when in standby service for an extended period of time, or when piping is emptied of liquid content either by draining or by inert gas pressure.

3.10 Tank Truck Loading/Unloading Rack Requirements (40 CFR 112.7(h))

The potential for discharges during tank truck loading and unloading operations is of particular concern at this facility. Unified Oil management is committed to ensuring the safe transfer of material to and from storage tanks. The following measures are implemented to prevent oil discharges during tank truck loading and unloading operations.

3.10.1 Secondary Containment (40 CFR 112.7(h)(1))

The facility has both a loading rack (for loading moderate capacity oil delivery tanker trucks) and an unloading area (where product is unloaded from large capacity tanker truck to the facility bulk storage tanks).

The loading rack and unloading area are co-located and are used by outside suppliers making deliveries to the facility and to load Unified Oil delivery trucks.

The tank truck loading rack/unloading area is surrounded with a 4-inch rollover asphalt berm that provides secondary containment in the event of a discharge during transfer operations. The secondary containment berm is designed to address the more stringent rack containment requirements of 40 CFR 112.7(h), which requires that the berm be sufficient to contain the capacity of the largest compartment, plus freeboard for precipitation. The curbed area provides a catchment capacity of 2,500 gallons, which is capable of containing the largest compartment of the petroleum suppliers truck making deliveries at this facility (maximum 2,000 gallons), and

is also capable of containing the capacity of Unified Oil's delivery trucks, which each have a total capacity of 2,000 gallons.

To minimize direct exposure to rain, and facilitate the cleanup of small spills that may occur during loading/unloading operations, the area is partially covered by a roof.

The area is graded to direct the flow of oil or water away from the vehicle, and the low point of the curbed area is fitted with a gate valve that is normally kept closed and locked. The key for that lock is kept in the main office. The berm is drained by Unified personnel after verifying that the retained water is free of oil. The accumulated water is released to the oil/water separator. The drain valve is closed and locked following drainage.

Although delivery trucks are usually empty while at the site for extended periods of time, Unified Oil periodically parks one of its two delivery trucks while full overnight. If a delivery truck is parked overnight or for an extended period of time while it still contains fuel, it is parked inside the loading rack/unloading area containment berm. As discussed above, the berm provides sufficient containment capacity for the truck volume, plus sufficient freeboard for 4 inches of precipitation.

3.10.2 Loading/Unloading Procedures (40 CFR 112.7(h)(2) and (3))

All suppliers must meet the minimum requirements and regulations for tank truck loading/unloading established by the U.S. Department of Transportation. Unified Oil ensures that the vendor understands the site layout, knows the protocol for entering the facility and unloading product, and has the necessary equipment to respond to a discharge from the vehicle or fuel delivery hose.

The Facility Manager or his/her designee supervises oil deliveries for all new suppliers, and periodically observes deliveries for existing, approved suppliers.

All loading and unloading of tank vehicles takes place only in the designated loading rack/unloading area.

Vehicle filling operations are performed by facility personnel trained in proper discharge prevention procedures. The truck driver or facility personnel remain with the vehicle at all times while fuel is being transferred. Transfer operations are performed according to the minimum procedures outlined in Table 3-3. This table is also posted next to the loading/unloading point.

Table 3-3: Fuel Transfer Procedures

Stage		Tasks
Prior to loading/ unloading	❑	Visually check all hoses for leaks and wet spots.
	❑	Verify that sufficient volume (ullage) is available in the storage tank or truck.
	❑	Lock in the closed position all drainage valves of the secondary containment structure.
	❑	Secure the tank vehicle with wheel chocks and interlocks.
	❑	Ensure that the vehicle's parking brakes are set.
	❑	Verify proper alignment of valves and proper functioning of the pumping system.
	❑	If filling a tank truck, inspect the lowermost drain and all outlets.
	❑	Establish adequate bonding/grounding prior to connecting to the fuel transfer point.
	❑	Turn off cell phone.
During loading/ unloading	❑	Driver must stay with the vehicle at all times during loading/unloading activities.
	❑	Periodically inspect all systems, hoses and connections.
	❑	When loading, keep internal and external valves on the receiving tank open along with the pressure relief valves.
	❑	When making a connection, shut off the vehicle engine. When transferring Class 3 materials, shut off the vehicle engine unless it is used to operate a pump.
	❑	Maintain communication with the pumping and receiving stations.
	❑	Monitor the liquid level in the receiving tank to prevent overflow.
	❑	Monitor flow meters to determine rate of flow.
	❑	When topping off the tank, reduce flow rate to prevent overflow.
After loading/ unloading	❑	Make sure the transfer operation is completed.
	❑	Close all tank and loading valves before disconnecting.
	❑	Securely close all vehicle internal, external, and dome cover valves before disconnecting.
	❑	Secure all hatches.
	❑	Disconnect grounding/bonding wires.
	❑	Make sure the hoses are drained to remove the remaining oil before moving them away from the connection. Use a drip pan.
	❑	Cap the end of the hose and other connecting devices before moving them to prevent uncontrolled leakage.
	❑	Remove wheel chocks and interlocks.
	❑	Inspect the lowermost drain and all outlets on tank truck prior to departure. If necessary, tighten, adjust, or replace caps, valves, or other equipment to prevent oil leaking while in transit.

3.11 Brittle Fracture Evaluation (40 CFR 112.7(i))

The only field-constructed tank at the facility is Tank #7. All other tanks were shop-built.

The shell thickness of Tank #7 is less than one-half inch. As discussed in the American Petroleum Institute (API) Standard 653 *Tank Inspection, Repair, Alteration, and Reconstruction* (API-653), brittle fracture is not a concern for tanks that have a shell thickness of less than one-half inch. This is the extent of the brittle fracture evaluation for this tank.

Nonetheless, in the event that Tank #7 undergoes a repair, alteration, reconstruction, or change in service that might affect the risk of a discharge or failure, the container will be evaluated for risk of discharge or failure, following API-653 or an equivalent approach, and corrective action will be taken as necessary.

3.12 Conformance with State and Local Applicable Requirements (40 CFR 112.7(j))

All bulk storage tanks at this facility are registered with the state and local authorities (Stonefield Fire Department) and have current certificates of registration and special use permits required by the local fire code.

Both USTs at the facility (Tanks #5 and 6) meet all requirements of Massachusetts UST regulation, including cathodic protection, double-wall construction, and monitoring systems, although Tank #6 is not subject to these requirements.

Treated storm water runoff is discharged to Silver Creek as permitted under NPDES permit #MA0001990. The maximum allowable daily oil/grease concentration is 15 mg/L. Grab samples are taken each quarter, following the monitoring requirements specified in the NPDES permit.

PART 4: Discharge Prevention – SPCC Provisions for Onshore Facilities (Excluding Production Facilities)

4.1 Facility Drainage (40 CFR 112.8(b))

Drainage from the concrete dike surrounding tanks 1, 2, and 3 is restrained by a manually-operated gate valve to prevent a discharge from entering the facility drainage system. The gate valve is normally sealed closed, except when draining the secondary containment structure. The content of the secondary containment dike is inspected by facility personnel prior to draining to ensure that only oil-free water is allowed to enter the facility storm water drainage system. The bypass valve is opened and resealed under direct personnel supervision. Drainage events are recorded in the log included in Appendix D to this SPCC Plan.

Any potential discharge from ASTs will be restrained by secondary containment structures. Discharges occurring during loading/unloading operations will be restrained by the rollover berm. The facility includes a drainage system and an oil/water separator, which are used to as containment for spill sources outside the main berm areas (fuel dispensing, overfills of 500-gallon AST (Tank#4), and transfers associated with the heating oil tank). The facility is equipped with an oil/water separator engineered to retain oil at the facility. This separator provides environmental protection equivalent to ponds, lagoons, or catchments basins required under 40 CFR 112.8(b)(3) and (4), as allowed in 40 CFR 112.7(a)(2). Discharges outside the containment areas, such as those occurring in the fuel dispensing area or while unloading heating oil, will flow by gravity into the drainage collection area and into the oil/water separator where oil will be retained until it can be pumped out.

4.2 Bulk Storage Containers (40 CFR 112.8(c))

Table 4-1 summarizes the construction, volume, and content of bulk storage containers at Unified Oil facility.

Table 4-1: List of Oil Containers

Tank	Location	Type (Construction Standard)	Capacity (gallons)	Content	Discharge Prevention & Containment
#1	Bulk Storage Area	AST vertical (UL142)	20,000	Diesel	Concrete dike. Liquid level gauge.
#2	Bulk Storage Area	AST horizontal (UL142)	20,000	Premium unleaded gasoline	Concrete dike. Liquid level gauge.
#3	Bulk Storage Area	AST horizontal (UL142)	20,000	Regular unleaded gasoline	Concrete dike. Liquid level gauge.
#4	Varies	AST dual wall, portable tank (UL142)	500	Regular unleaded gasoline	Double-wall. Liquid level gauge and interstitial monitoring system.
#5	Fuel Dispensing Area	UST dual wall (STI P3)	5,000	Diesel	Double-wall. Liquid level gauge, overfill protection system, and interstitial monitoring.
#6	Outside Office Building	UST dual wall (STI P3)	1,000	No. 2 Fuel Oil	Double-wall. Liquid level gauge, overfill protection system, and interstitial monitoring.
#7	Bulk Storage Area	AST vertical (field-erected). Heated during winter months (internal coils)	10,000	No. 6 Fuel Oil	Concrete dike. Liquid level gauge.
	Inside Maintenance Building	Steel drums	55	Motor oil and used oil	Spill pallets with built-in containment capacity. Building also serves as containment since floor drains flow into oil/water separator

4.2.1 Construction (40 CFR 112.8(c)(1))

All oil tanks used at this facility are constructed of steel, in accordance with industry specifications as described above. The design and construction of all bulk storage containers are compatible with the characteristics of the oil product they contain, and with temperature and pressure conditions.

Piping between fixed aboveground bulk storage tanks is made of steel and placed aboveground on appropriate supports designed to minimize erosion and stress.

4.2.2 Secondary Containment (40 CFR 112.8(c)(2))

A dike is provided around Tanks #1, 2, 3, and 7. Tanks #1, 2, and 3 each have a 20,000-gallon capacity. Tank #7 has a 10,000-gallon capacity. The dike has a total containment capacity of 27,316 gallons to allow sufficient volume for the largest tank and freeboard for precipitation. The freeboard is sufficient to contain a 4-inch rainfall corresponding to a 25-year, 24-hour storm event for this region of Massachusetts, as documented in Appendix F of this Plan. The floor and walls of the containment dike are constructed of poured concrete reinforced with steel. The concrete dike was built under the supervision of a structural engineer and in conformance with his specifications to be impervious to oil for a period of 72 hours. The facility is unattended for a maximum of 40 hours (Saturday evening through Monday morning) and therefore any spill into the diked area would be detected before it could escape the diked area. The surface of the concrete floor, the inside and outside of the walls, and the interface of the floor and walls, are visually inspected during the monthly facility inspection to detect any crack, signs of heaving or settlement, or other structural damage that could affect the ability of the dike to contain oil. Any damage is promptly corrected to prevent migration of oil into the ground, or out of the dike.

The 500-gallon portable AST tank is of double-wall construction and provides intrinsic secondary containment for 110 percent of the tank capacity. Since the secondary containment is not open to precipitation, this volume is sufficient to fully contain the product in the event of a leak from the primary container. The interstitial space between the primary and secondary containers is inspected on a monthly basis to detect any leak of product from the primary container. The container, however, is not equipped to prevent overfills as required by EPA policy in its memorandum on double-walled tanks. Therefore, general containment is required for potential tank overfills. This containment is accomplished through the facility drainage system and the oil/water separator, which provide environmentally equivalent protection as described in Section 3.1 of this Plan.

Both USTs are of double-wall construction and provide intrinsic secondary containment for 110 percent of the tank capacity. The interstitial space between the primary and secondary containers is inspected on a monthly basis to detect any leak of product from the primary container.

The 55-gallon drums are placed on spill pallets inside the maintenance shop. Each spill pallet provides 75 gallons of containment capacity, which is more than the required 55 gallons for any single drum since the drums are not exposed to precipitation. The floor of the maintenance shop

is impervious and sloped to direct any discharge occurring in the building away from doorways and towards the drainage system that leads to the facility oil/water separator.

4.2.3 Drainage of Diked Areas (40 CFR 112.8(c)(3))

The concrete dikes are drained under direct supervision of facility personnel. The accumulated water is observed for signs of oil prior to draining. The gate valves are normally kept in a closed position and locked except when draining the dike. Dike drainage events are recorded on the form included in Appendix D of this Plan; records are maintained at the facility for at least three years.

4.2.4 Corrosion Protection (40 CFR 112.8(c)(4))

Both metallic underground storage tanks, including Tank #6, which is subject to the requirements of 40 CFR part 112, are coated and cathodically protected to prevent corrosion and leakage into the ground. Pressure testing is performed on both buried storage tanks every two years following the requirements of 40 CFR part 280. The cathodic protection system is tested annually to verify its efficacy.

Cathodic protection is provided for both tanks in accordance with 40 CFR part 280 and meets the requirements of 40 CFR part 112.

Records of pressure tests are kept for at least three years.

4.2.5 Partially Buried and Bunkered Storage Tanks (40 CFR 112.8(c)(5))

This section is not applicable since there are no partially buried or bunkered storage tanks at this facility.

4.2.6 Inspections and Tests (40 CFR 112.8(c)(6))

Visual inspections of ASTs by facility personnel are performed according to the procedure described in this SPCC Plan. Leaks from tank seams, gaskets, rivets, and bolts are promptly corrected. Records of inspections and tests are signed by the inspector and kept at the facility for at least three years.

The scope and schedule of certified inspections and tests performed on the facility's ASTs are specified in STI Standard SP-001. The external inspection includes ultrasonic testing of the shell, as specified in the standard, or if recommended by the certified tank inspector to assess the integrity of the tank for continued oil storage.

Records of certified tank inspections are kept at the facility for at least three years. Shell test comparison records are retained for the life of the tanks.

Table 4-2 summarizes inspections and tests performed on bulk storage containers ("EE" indicates that an environmentally equivalent measure is implemented in place of the inspection/test, as discussed in Section 3.1 of this Plan).

Table 4-2: Scope and Frequency of Bulk Storage Containers Inspections and Tests

	Tank ID							
Inspection/Test	**#1**	**#2**	**#3**	**#4**	**#5**	**#6**	**#7**	**Drums**
Visual inspection by facility personnel (as per checklist of Appendix C)	M A	M A	M A	M A			M A	M A
External inspection by certified inspector (as per STI Standard SP-001)	20 yr	20 yr	10 yr	EE			10 yr	EE
Internal inspection by certified inspector (as per STI Standard SP-001)	†	†	20 yr*	EE			20 yr*	EE
Tank tightness test meeting requirements of 40 CFR 280					2 yr	2 yr		

Legend: M: Monthly
A: Annual
EE: Inspection not required given use of environmentally equivalent measure (refer to Section 3.1 of this Plan).
* Or earlier, as recommended by the certified inspector based on findings from an external inspection.
† Internal inspection may be recommended by the certified inspector based on findings from the external inspection.

The frequency above is based on implementation of a scheduled inspection/testing program. To initiate the program, ASTs will be inspected by the following dates:

- Tank #1: external inspection to be performed by December 31, 2009
- Tank #2: external inspection to be performed by December 31, 2009
- Tank #3: external inspection to be performed by December 31, 2006
- Tank #7: external Inspection to be performed by December 31, 2006

4.2.7 Heating Coils (40 CFR 112.8(c)(7))

Exhaust lines from internal heating coils for Tank #7 drain to the oil/water separator. The exhaust lines are monitored for signs of leakage as part of the monthly inspection of the facility.

4.2.8 Overfill Prevention Systems (40 CFR 112.8(c)(8))

All tanks are equipped with a direct-reading level gauge. Additionally, all four fixed ASTs (Tanks #1, 2, 3, and 7) are equipped with high level alarms set at 90 percent of the rated capacity. Tank

#4 does not have an overfill prevention system. General secondary containment is provided in the event of overfills, as described in this Plan.

Storage drums are not refilled, and therefore overfill prevention systems do not apply.

Tanks #5 and 6 are equipped with liquid level gauges and overfill protection systems. Liquid level sensing devices are tested on a monthly basis during the monthly inspection of the facility, following manufacturer recommendations. Venting capacity is suitable for the fill and withdrawal rates.

Facility personnel are present throughout the filling operations to monitor the product level in the tanks.

4.2.9 Effluent Treatment Facilities (40 CFR 112.8(c)(9))

The facility's storm water effluent discharged into Silver Creek is observed and records maintained according to the frequency required by NPDES permit MA0000157 (at least once per month) to detect possible upsets in the oil/water separator that could lead to a discharge.

4.2.10 Visible Discharges (40 CFR 112.8(c)(10))

Visible discharges from any container or appurtenance – including seams, gaskets, piping, pumps, valves, rivets, and bolts – are quickly corrected upon discovery.

Oil is promptly removed from the diked area and disposed of according to the waste disposal method described in Part 5 of this Plan.

4.2.11 Mobile and Portable Containers (40 CFR 112.8(c)(11))

Tank #4 is of double-wall design, which provides for adequate secondary containment in the event of leaks in the primary container shell. The interstitial space is monitored monthly for signs of leakage.

Small portable oil storage containers, such as 55-gallon drums, are stored inside the maintenance shop where secondary containment is provided by spill pallets and the floor is sloped to drain away from the floor drains and door. Any discharged material is quickly contained and cleaned up using sorbent pads and appropriate cleaning products.

Unified Oil delivery trucks generally return to the facility empty or product is returned to inventory. Whenever they remain at the facility while full for an extended period of time (such as when parking overnight with an emergency load of product), they are positioned in the loading rack/unloading area, which provides 2,500 gallons of secondary containment capacity (i.e., sufficient for the capacity of the delivery truck (2,000 gallons) and additional freeboard for 4 inches of precipitation).

4.3 Transfer Operations, Pumping, and In-Plant Processes (40 CFR 112.8(d))

Transfer operations at this facility include:

- The transfer of oil from the underground fuel oil storage tank to the furnace located in the basement of the office building. The oil is pumped from the oil storage tank by means of buried steel fuel lines and a suction pump system.
- The filling of facility delivery trucks using the gasoline dispenser.
- The transfer of oil into or from tanker trucks at the loading rack/unloading area.

All buried piping at this facility is cathodically protected against corrosion and is provided with a protective wrapping and coating. When a section of buried line is exposed, it is carefully examined for deterioration. If corrosion damage is found, additional examination and corrective action must be taken as deemed appropriate considering the magnitude of the damage. Additionally, Unified Oil conducts integrity and leak testing of buried piping at the time of installation, modification, construction, relocation, or replacement. Records of all tests are kept at the facility for at least three years.

Lines that are not in service or are on standby for an extended period of time are capped or blank-flanged and marked as to their origin.

All pipe supports are designed to minimize abrasion and corrosion and to allow for expansion and contraction. Pipe supports are visually inspected during the monthly inspection of the facility.

All aboveground piping and valves are examined monthly to assess their condition. Inspection includes aboveground valves, piping, appurtenances, expansion joints, valve glands and bodies, catch pans, pipeline supports, locking of valves, and metal surfaces. Observations are noted on the monthly inspection checklist provided in this Plan.

Warning signs are posted at appropriate locations throughout the facility to prevent vehicles from damaging aboveground piping and appurtenances. Most of the aboveground piping is located within areas that are not accessible to vehicular traffic (e.g., inside diked area). Brightly painted bollards are placed where needed to prevent vehicular collisions with equipment.

Part 5: Discharge Response

This section describes the response and cleanup procedures in the event of an oil discharge. The uncontrolled discharge of oil to groundwater, surface water, or soil is prohibited by state and possibly federal laws. Immediate action must be taken to control, contain, and recover discharged product.

In general, the following steps are taken:

- Eliminate potential spark sources;
- If possible and safe to do so, identify and shut down source of the discharge to stop the flow;
- Contain the discharge with sorbents, berms, fences, trenches, sandbags, or other material;
- Contact the Facility Manager or his/her alternate;
- Contact regulatory authorities and the response organization; and
- Collect and dispose of recovered products according to regulation.

For the purpose of establishing appropriate response procedures, this SPCC Plan classifies discharges as either “minor” or “major,” depending on the volume and characteristics of the material released.

A list of Emergency Contacts is provided in Appendix H. The list is also posted at prominent locations throughout the facility. A list of discharge response material kept at the facility is included in Appendix J.

5.1 Response to a Minor Discharge

A “minor” discharge is defined as one that poses no significant harm (or threat) to human health and safety or to the environment. Minor discharges are generally those where:

- The quantity of product discharged is small (e.g., may involve less than 10 gallons of oil);
- Discharged material is easily stopped and controlled at the time of the discharge;
- Discharge is localized near the source;
- Discharged material is not likely to reach water;
- There is little risk to human health or safety; and
- There is little risk of fire or explosion.

Minor discharges can usually be cleaned up by Unified Oil personnel. The following guidelines apply:

- Immediately notify the Facility Manager.
- Under the direction of the Facility Manager, contain the discharge with discharge response materials and equipment. Place discharge debris in properly labeled waste containers.
- The Facility Manager will complete the discharge notification form (Appendix I) and attach a copy to this SPCC Plan.
- If the discharge involves more than 10 gallons of oil, the Facility Manager will call the Massachusetts Department of Environmental Protection Incident Response Division (617-556-1133).

5.2 Response to a Major Discharge

A “major” discharge is defined as one that cannot be safely controlled or cleaned up by facility personnel, such as when:

- The discharge is large enough to spread beyond the immediate discharge area;
- The discharged material enters water;
- The discharge requires special equipment or training to clean up;
- The discharged material poses a hazard to human health or safety; or
- There is a danger of fire or explosion.

In the event of a major discharge, the following guidelines apply:

- All workers must immediately evacuate the discharge site via the designated exit routes and move to the designated staging areas at a safe distance from the discharge. Exit routes are included on the facility diagram and posted in the maintenance building, in the office building, and on the outside wall of the outside shed that contains the spill response equipment.
- If the Facility Manager is not present at the facility, the senior on-site person notifies the Facility Manager of the discharge and has authority to initiate notification and response. Certain notifications are dependent on the circumstances and type of discharge. For example, if oil reaches a sanitary sewer, the publicly owned treatment works (POTW) should be notified immediately. A discharge that threatens Silver Creek may require immediate notification to downstream users such as the town drinking water plant, which has an intake located on Silver Creek.
- The Facility Manager (or senior on-site person) must call for medical assistance if workers are injured.
- The Facility Manager (or senior on-site person) must notify the Fire Department or Police Department.
- The Facility Manager (or senior on-site person) must call the spill response and cleanup contractors listed in the Emergency Contacts list in Appendix H.

- The Facility Manager (or senior on-site person) must immediately contact the Massachusetts Department of Environmental Protection Incident Response Division (617-556-1133) and the National Response Center (888-424-8802).
- The Facility Manager (or senior on-site person) must record the call on the Discharge Notification form in Appendix I and attach a copy to this SPCC Plan.
- The Facility Manager (or senior on-site person) coordinates cleanup and obtains assistance from a cleanup contractor or other response organization as necessary.

If the Facility Manager is not available at the time of the discharge, then the next highest person in seniority assumes responsibility for coordinating response activities.

5.3 Waste Disposal

Wastes resulting from a minor discharge response will be containerized in impervious bags, drums, or buckets. The facility manager will characterize the waste for proper disposal and ensure that it is removed from the facility by a licensed waste hauler within two weeks.

Wastes resulting from a major discharge response will be removed and disposed of by a cleanup contractor.

5.4 Discharge Notification

Any size discharge (i.e., one that creates a sheen, emulsion, or sludge) that affects or threatens to affect navigable waters or adjoining shorelines must be reported immediately to the National Response Center (1-800-424-8802). The Center is staffed 24 hours a day.

A summary sheet is included in Appendix I to facilitate reporting. The person reporting the discharge must provide the following information:

- ❑ Name, location, organization, and telephone number
- ❑ Name and address of the party responsible for the incident
- ❑ Date and time of the incident
- ❑ Location of the incident
- ❑ Source and cause of the release or discharge
- ❑ Types of material(s) released or discharged
- ❑ Quantity of materials released or discharged
- ❑ Danger or threat posed by the release or discharge
- ❑ Number and types of injuries (if any)
- ❑ Media affected or threatened by the discharge (i.e., water, land, air)
- ❑ Weather conditions at the incident location
- ❑ Any other information that may help emergency personnel respond to the incident

Contact information for reporting a discharge to the appropriate authorities is listed in Appendix H and is also posted in prominent locations throughout the facility (e.g., in the office building, in the maintenance building, and at the loading rack/unloading area).

In addition to the above reporting, 40 CFR 112.4 requires that information be submitted to the United States Environmental Protection Agency (EPA) Regional Administrator and the appropriate state agency in charge of oil pollution control activities (see contact information in Appendix H) whenever the facility discharges (as defined in 40 CFR 112.1(b)) *more than 1,000 gallons of oil in a single event,* or discharges (as defined in 40 CFR 112.1(b)) *more than 42 gallons of oil in each of two discharge incidents within a 12-month period.* The following information must be submitted to the EPA Regional Administrator and to MADEP within 60 days:

- Name of the facility;
- Name of the owner/operator;
- Location of the facility;
- Maximum storage or handling capacity and normal daily throughput;
- Corrective action and countermeasures taken, including a description of equipment repairs and replacements;
- Description of facility, including maps, flow diagrams, and topographical maps;
- Cause of the discharge(s) to navigable waters and adjoining shorelines, including a failure analysis of the system and subsystem in which the failure occurred;
- Additional preventive measures taken or contemplated to minimize possibility of recurrence; and
- Other pertinent information requested by the Regional Administrator.

A standard report for submitting the information to the EPA Regional Administrator and to MADEP is included in Appendix K of this Plan.

5.5 Cleanup Contractors and Equipment Suppliers

Contact information for specialized spill response and cleanup contractors are provided in Appendix H. These contractors have the necessary equipment to respond to a discharge of oil that affects Silver Creek or adjoining shorelines, including floating booms and oil skimmers.

Spill kits are located at the loading rack/unloading area and inside the maintenance building. The inventory of response supplies and equipment is provided in Appendix J of this Plan. The inventory is verified on a monthly basis. Additional supplies and equipment may be ordered from the following sources:

AA Equipment Co.	(800) 555-5556
Eastern Sorbent	(800) 555-5557

Appendix A
Site Plan and Facility Diagram

Figure A-1: Site Plan.

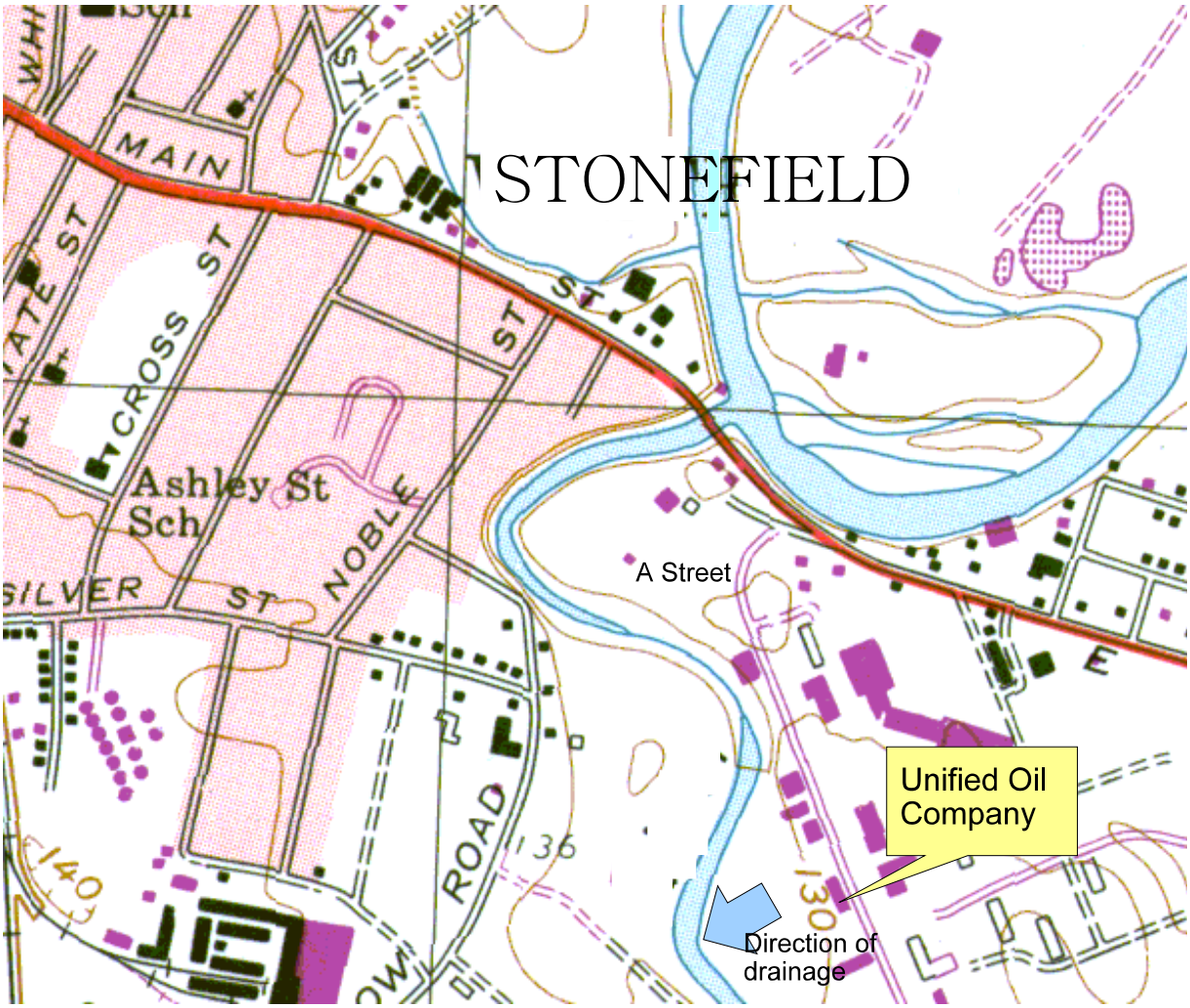
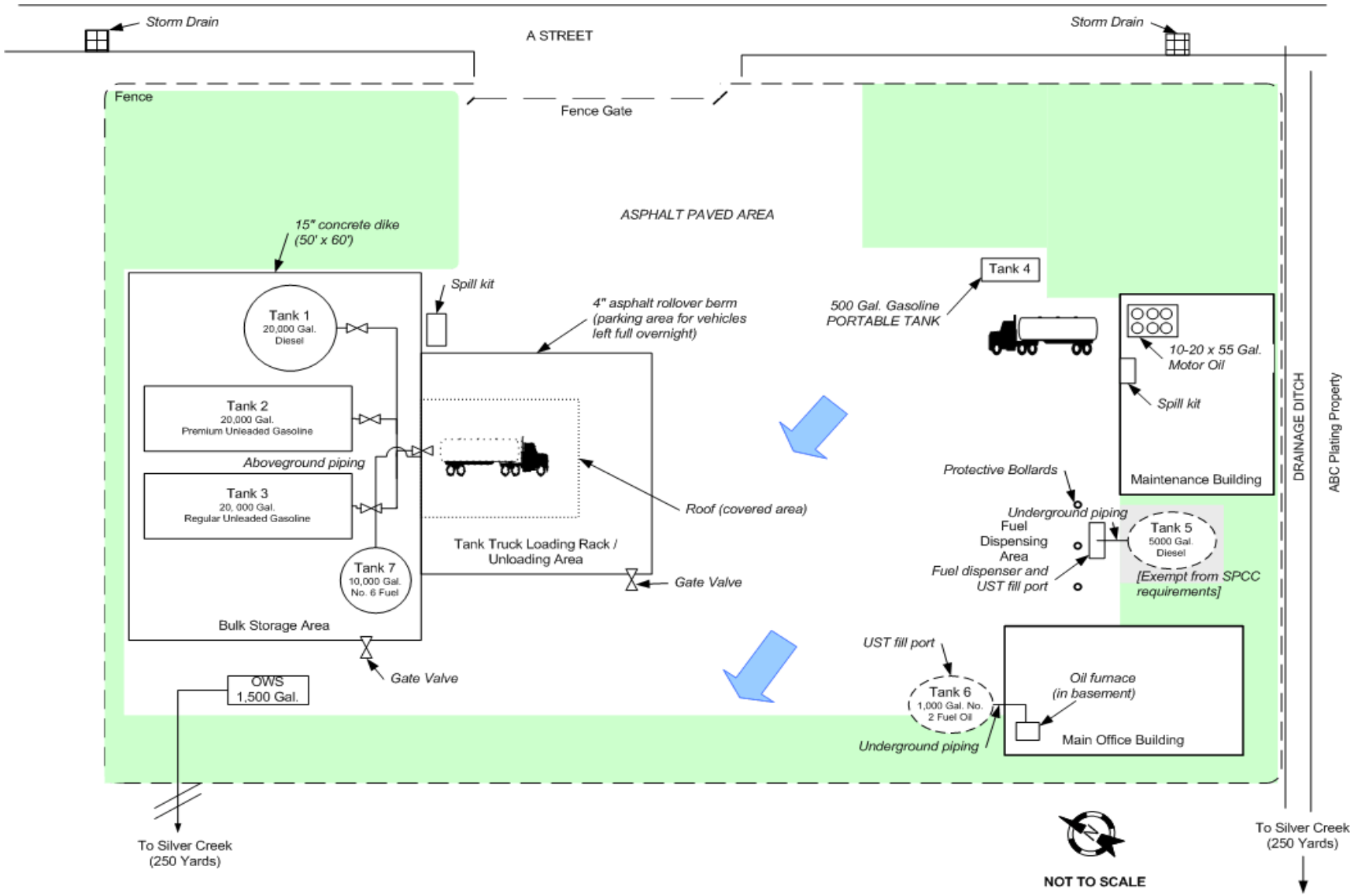


Figure A-2: Facility Diagram.



Appendix B
Substantial Harm Determination

Facility Name: Unified Oil Company
Facility Address: 123 A Street
Stonefield, MA 02000

1. Does the facility transfer oil over water to or from vessels and does the facility have a total oil storage capacity greater than or equal to 42,000 gallons?
Yes ☐ No ■

2. Does the facility have a total oil storage capacity greater than or equal to 1 million gallons and does the facility lack secondary containment that is sufficiently large to contain the capacity of the largest aboveground oil storage tank plus sufficient freeboard to allow for precipitation within any aboveground storage tank area?
Yes ☐ No ■

3. Does the facility have a total oil storage capacity greater than or equal to 1 million gallons and is the facility located at a distance (as calculated using the appropriate formula in 40 CFR part 112 Appendix C, Attachment C-III or a comparable formula) such that a discharge from the facility could cause injury to fish and wildlife and sensitive environments?
Yes ☐ No ■

4. Does the facility have a total oil storage capacity greater than or equal to 1 million gallons and is the facility located at a distance (as calculated using the appropriate formula in 40 CFR part 112 Appendix C, Attachment C-III or a comparable formula) such that a discharge from the facility would shut down a public drinking water intake?
Yes ☐ No ■

5. Does the facility have a total oil storage capacity greater than or equal to 1 million gallons and has the facility experienced a reportable oil spill in an amount greater than or equal to 10,000 gallons within the last 5 years?
Yes ☐ No ■

Certification

I certify under penalty of law that I have personally examined and am familiar with the information submitted in this document, and that based on my inquiry of those individuals responsible for obtaining this information, I believe that the submitted information is true, accurate, and complete.

Susan Blake	*Facility Manager*
Signature	Title
Susan Blake	*May 12, 2003*
Name (type or print)	Date

APPENDIX C
Facility Inspection Checklists

The following checklists are to be used for monthly and annual facility-conducted inspections. Completed checklists must be signed by the inspector and maintained at the facility, with this SPCC Plan, for at least three years.

Monthly Inspection Checklist

This inspection record must be completed *each month* except the month in which an annual inspection is performed. Provide further description and comments, if necessary, on a separate sheet of paper and attach to this sheet. *Any item that receives "yes" as an answer must be described and addressed immediately.

	Y*	N	Description & Comments
Storage tanks			
Tank surfaces show signs of leakage			
Tanks are damaged, rusted or deteriorated			
Bolts, rivets, or seams are damaged			
Tank supports are deteriorated or buckled			
Tank foundations have eroded or settled			
Level gauges or alarms are inoperative			
Vents are obstructed			
Secondary containment is damaged or stained			
Water/product in interstice of double-walled tank			
Dike drainage valve is open or is not locked			
Piping			
Valve seals, gaskets, or other appurtenances are leaking			
Pipelines or supports are damaged or deteriorated			
Joints, valves and other appurtenances are leaking			
Buried piping is exposed			
Loading/unloading and transfer equipment			
Loading/unloading rack is damaged or deteriorated			
Connections are not capped or blank-flanged			
Secondary containment is damaged or stained			
Berm drainage valve is open or is not locked			
Oil/water separator			
Oil/water separator > 2 inches of accumulated oil			
Oil/water separator effluent has a sheen			
Security			
Fencing, gates, or lighting is non-functional			
Pumps and valves are locked if not in use			
Response Equipment			
Response equipment inventory is complete			

Date: _____ **Signature:** _____

Annual Facility Inspection Checklist

This inspection record must be completed *each year.* If any response requires further elaboration, provide comments in Description & Comments space provided. Further description and comments, if necessary, must be provided on a separate sheet of paper and attached to this sheet. *Any item that receives "yes" as an answer must be described and addressed immediately.

	Y*	N	Description & Comments
Storage tanks			
Tank #1			
Tank surfaces show signs of leakage			
Tank is damaged, rusted or deteriorated			
Bolts, rivets or seams are damaged			
Tank supports are deteriorated or buckled			
Tank foundations have eroded or settled			
Level gauges or alarms are inoperative			
Vents are obstructed			
Tank #2			
Tank surfaces show signs of leakage			
Tank is damaged, rusted, or deteriorated			
Bolts, rivets, or seams are damaged			
Tank supports are deteriorated or buckled			
Tank foundations have eroded or settled			
Level gauges or alarms are inoperative			
Vents are obstructed			
Tank #3			
Tank surfaces show signs of leakage			
Tank is damaged, rusted, or deteriorated			
Bolts, rivets, or seams are damaged			
Tank supports are deteriorated or buckled			
Tank foundations have eroded or settled			
Level gauges or alarms are inoperative			
Vents are obstructed			
Tank #4			
Tank surfaces show signs of leakage			
Tank is damaged, rusted or deteriorated			
Bolts, rivets or seams are damaged			
Tank supports are deteriorated or buckled			
Tank foundations have eroded or settled			
Level gauges or alarms are inoperative			

	Y*	N	Description & Comments
Vents are obstructed			
Oil is present in the interstice			
Tank #7			
Tank surfaces show signs of leakage			
Tank is damaged, rusted, or deteriorated			
Bolts, rivets, or seams are damaged			
Tank supports are deteriorated or buckled			
Tank foundations have eroded or settled			
Level gauges or alarms are inoperative			
Leakage in exhaust from heating coils			
Concrete dike			
Secondary containment is stained			
Dike drainage valve is open or is not locked			
Dike walls or floors are cracked or are separating			
Dike is not retaining water (following large rainfall)			
Piping			
Valve seals or gaskets are leaking			
Pipelines or supports are damaged or deteriorated			
Joints, valves and other appurtenances are leaking			
Buried piping is exposed			
Out-of-service pipes are not capped			
Warning signs are missing or damaged			
Loading/unloading and transfer equipment			
Loading/unloading rack is damaged or deteriorated			
Connections are not capped or blank-flanged			
Rollover berm is damaged or stained			
Berm drainage valve is open or is not locked			
Drip pans have accumulated oil or are leaking			
Oil/water separator			
Oil/water separator > 2 inches of accumulated oil			
Oil/water separator effluent has a sheen			
Security			
Fencing, gates, or lighting is non-functional			
Pumps and valves are not locked (and not in use)			
Response equipment			
Response equipment inventory is incomplete			

Annual reminders:

- Hold SPCC Briefing for all oil-handling personnel (and update briefing log in the Plan);
- Check contact information for key employees and response/cleanup contractors and update them in the Plan as needed;

Additional Remarks:

Date: _____ Signature: _____

APPENDIX D
Record of Containment Dike Drainage

This record must be completed when rainwater from diked areas is drained into a storm drain or into an open watercourse, lake, or pond, and bypasses the water treatment system. The bypass valve must normally be sealed in closed position. It must be opened and resealed following drainage under responsible supervision.

Date	**Diked Area**	**Presence of**	**Time**	**Time**	**Signature**
06/05/2003	Area 1	No oil	08:00	10:00	Susan Blake
07/15/2003	Area 1	No oil	08:20	10:30	Susan Blake

APPENDIX E
Record of Annual Discharge Prevention Briefings and Training

Briefings will be scheduled and conducted by the facility owner or operator for operating personnel at regular intervals to ensure adequate understanding of this SPCC Plan. The briefings will also highlight and describe known discharge events or failures, malfunctioning components, and recently implemented precautionary measures and best practices. Personnel will also be instructed in operation and maintenance of equipment to prevent the discharge of oil, and in applicable pollution laws, rules, and regulations. Facility operators and other personnel will have an opportunity during the briefings to share recommendations concerning health, safety, and environmental issues encountered during facility operations.

Date	Subjects Covered	Employees in Attendance	Instructor(s)

APPENDIX F
Calculation of Secondary Containment Capacity

The maximum 24-hour rainfall recorded in the last 25 years at this location is **3.75 inches**.

Bulk Storage Dike

Capacity of Tanks within the Diked Area:
Tank 1 = 20,000 gallons (saddle-mounted tank, no significant displacement)
Tank 2 = 20,000 gallons (saddle-mounted tank, no significant displacement)
Tank 3 = 20,000 gallons (need to account for tank displacement)
Tank 7 = 10,000 gallons (on legs, no significant displacement)

Dike Dimensions:
Dike footprint = 50 feet x 60 feet
Dike height = 15 inches = 1.25 feet
Dike volume = 50' x 60' x 1.25' = 3750 ft^3 x 7.48 gal/ft^3 = 28,050 gallons

Displacement Volume of Tank 3:
Tank diameter = 10 feet
3.1415 * $(10\ ft)^2$ / 4 * 1.25' = 98 ft^3 x 7.48 gal/ft^3 = 734 gallons

Available Freeboard for Precipitation:
28,050 gallons - (20,000 gallons + 734 gallons) = 7,316 gallons
7,316 gallons / 7.48 gallons/ft^3 / (50 ft x 60 ft) = 0.33 ft = **4 inches**

The dike therefore **provides sufficient storage capacity for the largest bulk storage container within the diked area, tank displacement, and precipitation**. The containment capacity is equivalent to 137% of the capacity of the largest container ((28,050 gallons - 734 gallons)/20,000 gallons).

Loading Rack/Unloading Area Rollover Berm

Capacity of Largest Tank Truck Compartment:
2,000 gallons

Berm Dimensions:
Berm footprint = 28 feet x 45 feet (50% of the berm surface area is covered by the roof)
Berm height = 4.5 inches = 0.375 feet
Berm volume = 28 ft x 45 ft x 0.375 ft = 473 ft^3 x 7.48 gal/ft^3 = 3,534 gallons

Available Freeboard for Precipitation:
Since 50% of the surface area of the berm is covered by a roof, the volume of precipitation that enters the berm is reduced.

Minimum freeboard required = 28 ft x 45 ft x 0.5 x 3.75/12 = 197 ft^3 = 1,472 gallons
Actual freeboard = 3,534 gallons - 2,000 gallons = 1,534 gallons

The berm therefore **provides sufficient storage capacity to contain both the largest compartment of tank trucks loading/unloading at the facility, and the volume of precipitation that enters the berm**.

APPENDIX G
Records of Tank Integrity and Pressure Tests

Attach copies of official records of tank integrity and pressure tests.

APPENDIX H
Emergency Contacts

Designated person responsible for spill prevention: ***Susan Blake, Facility Manager***
781-555-5550

EMERGENCY TELEPHONE NUMBERS:

Facility	
Susan Blake, Facility Manager	781-555-5550
Local Emergency Response	
Stonefield Fire Department	911 or 781-555-5551
St. Mary's Hospital	781-555-5552
Response/Cleanup Contractors	
EZ Clean	617-555-5554
Stonefield Oil Removal	781-555-5555
Notification	
Massachusetts Department of Environmental Protection, Incident Response Division	617-556-1133
National Response Center	800-424-8802
United States Environmental Protection Agency, Region 1	888-372-7341

APPENDIX I
Discharge Notification Form

Part A: Discharge Information	
General information when reporting a spill to outside authorities: Name: Unified Oil Company Address: 123 A Street Stonefield, MA 02000 Telephone: (781) 555-5556 Owner/Operator: Blake and Daughters, Inc. 20 Fairview Road Stonefield, MA 02000 Primary Contact: Susan Blake, Facility Manager Work: (781)555-5550 Cell (24 hrs): (781)555-5559	
Type of oil:	Discharge Date and Time:
Quantity released:	Discovery Date and Time:
Quantity released to a waterbody:	Discharge Duration:
Location/Source:	
Actions taken to stop, remove, and mitigate impacts of the discharge:	
Affected media: ☐ air ☐ water ☐ soil	☐ storm water sewer/POTW ☐ dike/berm/oil-water separator ☐ other: _____
Notification person:	Telephone contact: Business: 24-hr:
Nature of discharges, environmental/health effects, and damages: Injuries, fatalities or evacuation required?	

Part B: Notification Checklist		
	Date and time	Name of person receiving call
Discharge in any amount		
Susan Blake, Facility Manager and Response Coordinator (781) 555-5550 / (781) 555-5559		
Discharge in amount exceeding 10 gallons and *not affecting a waterbody or groundwater*		

Local Fire Department Fire Chief: D. Evans (781) 555-1258 or 911		
Massachusetts Department of Environmental Protection (888) 304-1133 or (617) 553-1133		
Discharge in any amount and affecting (or threatening to affect) a waterbody		
Local Fire Department Fire Chief: D. Evans (781) 555-1258 or 911		
Massachusetts Department of Environmental Protection (888) 304-1133 or (617) 553-1133		
National Response Center (800) 424-8802		
*Town of Stonefield POTW Plant Operator: K. Bromberg (781) 555-5453		
Town of Stonefield Drinking Water Plant Plant Operator: D. Lopez (781) 555-5450		
EZ Clean (617) 555-5554		

* The POTW should be notified of a discharge only if oil has reached or threatens sewer drains that connect to the POTW collection system.

APPENDIX J
Discharge Response Equipment Inventory

The discharge response equipment inventory is verified during the monthly inspection and must be replenished as needed.

Tank Truck Loading/Unloading Area

☐	Empty 55-gallons drums to hold contaminated material	4
☐	Loose absorbent material	200 pounds
☐	Absorbent pads	3 boxes
☐	Nitrile gloves	6 pairs
☐	Neoprene gloves	6 pairs
☐	Vinyl/PVC pull-on overboots	6 pairs
☐	Non-sparking shovels	3
☐	Brooms	3
☐	Drain seals or mats	2
☐	Sand bags	12

Maintenance Building

☐	Empty 55-gallons drums to hold contaminated material	1
☐	Loose absorbent material	50 pounds
☐	Absorbent pads	1 box
☐	Nitrile gloves	2 pairs
☐	Neoprene gloves	2 pairs
☐	Vinyl/PVC pull-on overboots	2 pairs
☐	Non-sparking shovels	1
☐	Brooms	1
☐	Drain seals or mats	1

APPENDIX K
Agency Notification Standard Report

Information contained in this report, and any supporting documentation, must be submitted to the EPA Region 1 Regional Administrator, and to MADEP, within 60 days of the qualifying discharge incident.

Facility:	*Unified Oil Company*
Owner/operator:	*Blake and Daughters* *20 Fairview Road* *Stonefield, MA 02000*
Name of person filing report:	
Location:	*123 A Street* *Stonefield, MA 02000*
Maximum storage capacity:	*74,600 gallons*
Daily throughput:	*8,000 gallons*
Nature of qualifying incident(s): ☐ Discharge to navigable waters or adjoining shorelines exceeding 1,000 gallons ☐ Second discharge exceeding 42 gallons within a 12-month period.	
Description of facility (attach maps, flow diagrams, and topographical maps): *Unified Oil distributes a variety of petroleum products to primarily commercial customers. The facility handles, stores, uses, and distributes petroleum products in the form of gasoline, diesel, No. 2 fuel oil, No. 6 fuel oil, and motor oil. Unified Oil receives products by common carrier via tanker truck. The products are stored in five aboveground storage tanks (ASTs) and in one underground storage tank (UST). They are delivered to customers by Unified Oil trucks or by independent contractors. The facility refuels its own two delivery trucks from an underground diesel tank connected to a fueling pump.* *Unified Oil is located in a primarily commercial area at 123 A Street in Stonefield, Massachusetts. The site is comprised of approximately 2 acres of land and is bordered to the East by A Street, to the West by Silver Creek, and to the North by ABC Plating Co.* *Site improvements include an office building, a maintenance shop, a tanker truck loading rack and unloading area, and product storage and handling areas. Petroleum products are stored in the bulk storage area, the maintenance building, and the office building.*	

Agency Notification Standard Report (cont'd)
Cause of the discharge(s), including a failure analysis of the system and subsystems in which the failure occurred:
Corrective actions and countermeasures taken, including a description of equipment repairs and replacements:
Additional preventive measures taken or contemplated to minimize possibility of recurrence:
Other pertinent information:

Appendix E: Sample Production Facility Plan

Disclaimer - Appendix E

The sample Spill Prevention, Control and Countermeasure (SPCC) Plan in Appendix E is intended to provide examples and illustrations of how a production facility could address a variety of scenarios in its SPCC Plan. The “facility” is not an actual facility, nor does it represent any actual facility or company. Rather, EPA is providing illustrative examples of the type and amount of information that is appropriate SPCC Plan language for these hypothetical situations.

Because the SPCC rule is designed to give each facility owner/operator the flexibility to tailor the facility’s SPCC Plan to the facility’s circumstances, this sample SPCC Plan is not a template to be adopted by a facility; doing so does not mean that the facility will be in compliance with the SPCC rule requirements. Nor is the sample plan a template that must be followed in order for the facility to be considered in compliance with the SPCC rule.

SPILL PREVENTION, CONTROL, AND COUNTERMEASURE PLAN

Clearwater Oil Company

Big Bear Lease No. 2 Production Facility

5800 Route 417
Madison, St. Anthony Parish, Louisiana 73506

Clearwater

Prepared by
Montgomery Engineering, Inc.

November 23, 2003

Version 1.0, 11/28/2005

Table of Contents

	Page
Cross-Reference with SPCC Rule	4
Introduction	5
Management Approval	6
Professional Engineer Certification	6
Plan Review	7
Location of SPCC Plan	7
Certification of Substantial Harm Determination	8
Part I - General Facility Information	
1.1 Company Information	9
1.2 Contact Information	9
1.3 Facility Layout Diagram	10
1.4 Facility Location and Operations	10
1.5 Oil Storage and Handling	11
1.6 Proximity to Navigable Waters	12
1.7 Conformance with Applicable State and Local Requirements	12
Part II - Spill Response and Reporting	
2.1 Discharge Discovery and Reporting	13
2.2 Spill Response Materials	14
2.3 Spill Mitigation Procedures	15
2.4 Disposal Plan	16
Part III - Spill Prevention, Control, and Countermeasure Provisions	
3.1 Potential Discharge Volume and Direction of Flow	18
3.2 Containment and Diversionary Structures	19
3.3 Other Spill Prevention Measures	22
3.4 Inspections, Tests, and Records	23
3.5 Personnel, Training, and Discharge Prevention Procedures	27
Appendix A - Facility Diagrams	30
Appendix B - Tank Truck Loading Procedure	32
Appendix C - Monthly Inspection Checklist	33
Appendix D - Record of Dike Drainage	34
Appendix E - Discharge Prevention Briefing Log	35
Appendix F - Discharge Notification Procedures	36
Appendix G - Equipment Shut-off Procedures	41
Appendix H - Written Commitment of Manpower, Equipment, and Materials	42
Appendix I - Oil Spill Contingency Plan	43

Page

List of Tables

Table 0-1: Record of plan review and changes 7
Table 1-1: Facility contact information 10
Table 1-2: Characteristics of oil containers 11
Table 3-1: Potential discharge volume and direction of flow 18
Table 3-2: Berm capacity calculations 21
Table 3-3: Scope of daily examinations 24
Table 3-4: Scope of monthly inspections 25
Table 3-5: Schedule of periodic condition inspection of bulk storage containers 26
Table 3-6: Components of flowline maintenance program 27

List of Figures

Figure A-1: Site plan. 30
Figure A-2: Production facility diagram. 31

Cross-Reference with SPCC Rule

Provision*	Plan Section	Page(s)
112.3(d)	Professional Engineer Certification	6
112.3(e)	Location of SPCC Plan	7
112.5	Plan Review	7
112.7	Management Approval	6
112.7	Cross-Reference with SPCC Rule	4
112.7(a)(3)	Part I - General Information and Facility Diagram Appendix A: Facility Diagrams	9-12 Appendix A
112.4 and 112.7(a)(4)	2.1 Discharge Discovery and Reporting Appendix F: Discharge Notification	13-15 Appendix F
112.7(a)(5)	2.2 Spill Mitigation Procedures Appendix I: Oil Spill Contingency Plan	15-16 Appendix I
112.7(b)	3.1 Potential Discharge Volume and Direction of Flow	18-19
112.7(c)	3.2 Containment and Diversionary Structures	19-21
112.7(d)	3.2.3 Practicability of Secondary Containment Appendix H: Written Commitment of manpower, equipment, and materials Appendix I: Oil Spill Contingency Plan	21 Appendix H Appendix I
112.7(e)	3.4 Inspections, Tests, and Records Appendix C: Facility Inspection Checklists	23-26 Appendix C
112.7(f)	3.5 Personnel, Training, and Discharge Prevention Procedures Appendix E: Discharge Prevention Briefing Log	27-29 Appendix E
112.7(g)	Security – N/A (does not apply to production facilities)	N/A
112.7(h)	Loading/Unloading Rack – N/A (no rack present at this facility)	N/A
112.7(i)	Brittle Fracture Evaluation – N/A (no field-erected aboveground tank at this facility)	26
112.7(j)	1.7 Conformance with Applicable State and Local Requirements	12
112.9(b)	3.2.1 Oil Production Facility Drainage Appendix D: Record of Dike Drainage	20 Appendix D
112.9(c)(1)	1.5.1 Production Equipment	11
112.9(c)(2)	3.2.2 Secondary Containment for Bulk Storage Containers	19-21
112.9(c)(3)	3.4 Inspections, Tests, and Records Appendix C: Monthly Inspection Checklist	23-26 Appendix C
112.9(c)(4)	3.3.1 Bulk Storage Containers Overflow Prevention	22
112.9(d)(1)	3.3.2 Transfer Operations and Saltwater Disposal System	22-23
112.9(d)(2)	3.3.2 Transfer Operations and Saltwater Disposal System	22-23
112.9(d)(3)	3.4.5 Flowline Maintenance Program	26-27

* Only relevant rule provisions are indicated. For a complete list of SPCC requirements, refer to the full text of 40 CFR part 112.

Introduction

The purpose of this Spill Prevention Control and Countermeasure (SPCC) Plan is to describe measures implemented by Clearwater to prevent oil discharges from occurring, and to prepare Clearwater to respond in a safe, effective, and timely manner to mitigate the impacts of a discharge from the Big Bear Lease No. 2 production facility. This SPCC Plan has been prepared and implemented in accordance with the SPCC requirements contained in 40 CFR part 112.

In addition to fulfilling requirements of 40 CFR part 112, this SPCC Plan is used as a reference for oil storage information and testing records, as a tool to communicate practices on preventing and responding to discharges with Clearwater employees and contractors, as a guide on facility inspections, and as a resource during emergency response.

Management Approval

40 CFR 112.7

Clearwater Oil Company ("Clearwater") is committed to maintaining the highest standards for preventing discharges of oil to navigable waters and the environment through the implementation of this SPCC Plan. This SPCC Plan has the full approval of Clearwater management. Clearwater's management has committed the necessary resources to implement the measures described in this Plan.

Bill Laurier is the Designated Person Accountable for Oil Spill Prevention at this Clearwater facility and has the authority to commit the necessary resources to implement the Plan as described.

Authorized Facility Representative:	Bill Laurier
Signature:	Bill Laurier
Title:	Field Operations Manager
Date:	November 23, 2003

Professional Engineer Certification

40 CFR 112.3(d)

The undersigned Registered Professional Engineer is familiar with the requirements of Part 112 of Title 40 of the *Code of Federal Regulations* (40 CFR part 112) and has visited and examined the facility, or has supervised examination of the facility by appropriately qualified personnel. The undersigned Registered Professional Engineer attests that this Spill Prevention, Control, and Countermeasure Plan has been prepared in accordance with good engineering practice, including consideration of applicable industry standards and the requirements of 40 CFR part 112; that procedures for required inspections and testing have been established; and that this Plan is adequate for the facility. [112.3(d)]

This certification in no way relieves the owner or operator of the facility of his/her duty to prepare and fully implement this SPCC Plan in accordance with the requirements of 40 CFR part 112.

Peter E. Trudeau — Signature

November 23, 2003 — Date

Peter E. Trudeau, P.E.
Name of Professional Engineer

90535055 — Registration Number

Louisiana — Issuing State

PE Seal

Peter E. Trudeau
LA #90535055

Plan Review

40 CFR 112.5

In accordance with 40 CFR 112.5, Clearwater Oil periodically reviews and evaluates this SPCC Plan for any change in the facility design, construction, operation, or maintenance that materially affects the facility's potential for an oil discharge. Clearwater reviews this SPCC Plan at least once every five years. Revisions to the Plan, if any are needed, are made within six months of this five-year review. Clearwater will implement any amendment as soon as possible, but not later than six months following preparation of any amendment. A registered PE certifies any technical amendment to the Plan, as described above, in accordance with 40 CFR 112.3(d).

Scheduled five-year reviews and Plan amendments are recorded in Table 0-1. This log must be completed even if no amendment is made to the Plan. Unless a technical or administrative change prompts an earlier review, the next scheduled review of this Plan must occur by *November 23, 2008.*

Table 0-1: Record of Plan Review and Changes

Date	Authorized Individual	Review Type	PE Certification	Summary of Changes
11/23/03	Bill Laurier	Initial Plan	Yes	N/A
04/14/04	Bill Laurier	Off-cycle review	No	Changed telephone number for Field Operations Manager. Corrected page numbers in Table of Content. Non-technical amendments, no PE certification is needed.

Location of SPCC Plan

40 CFR 112.3(e)

In accordance with 40 CFR 112.3(e), and because the facility is normally unmanned, a complete copy of this SPCC is maintained at the field office closest to the facility, which is located approximately 25 miles from the facility at 2451 Mountain Drive, Ridgeview, LA. Additional copies are available at the Clearwater Oil Company management office, located at 13000 Main Street, Suite 400, Houston, TX.

Certification of Substantial Harm Determination

40 CFR 112.20(e), 40 CFR 112.20(f)(1)

Facility Name: **Clearwater Oil Company, Big Bear Lease No. 2**

1. Does the facility transfer oil over water to or from vessels and does the facility have a total oil storage capacity greater than or equal to 42,000 gallons?
   Yes ☐ No ■

2. Does the facility have a total oil storage capacity greater than or equal to 1 million gallons and does the facility lack secondary containment that is sufficiently large to contain the capacity of the largest aboveground oil storage tank plus sufficient freeboard to allow for precipitation within any aboveground storage tank area?
   Yes ☐ No ■

3. Does the facility have a total oil storage capacity greater than or equal to 1 million gallons and is the facility located at a distance (as calculated using the appropriate formula) such that a discharge from the facility could cause injury to fish and wildlife and sensitive environments?
   Yes ☐ No ■

4. Does the facility have a total oil storage capacity greater than or equal to 1 million gallons and is the facility located at a distance (as calculated using the appropriate formula) such that a discharge from the facility would shut down a public drinking water intake?
   Yes ☐ No ■

5. Does the facility have a total oil storage capacity greater than or equal to 1 million gallons and has the facility experienced a reportable oil spill in an amount greater than or equal to 10,000 gallons within the last 5 years?
   Yes ☐ No ■

Certification

I certify under penalty of law that I have personally examined and am familiar with the information submitted in this document, and that based on my inquiry of those individuals responsible for obtaining this information, I believe that the submitted information is true, accurate, and complete.

Bill Laurier	*Field Operations Manager*
Signature	Title
Bill Laurier	*November 23, 2003*
Name (type or print)	Date

PART I - GENERAL FACILITY INFORMATION

40 CFR 112.7(a)(3)

1.1 Company Information

Name of Facility:	Clearwater Oil Company Big Bear Lease No. 2
Type	Onshore oil production facility
Date of Initial Operation	2002
Location	5800 Route 417 Madison, St. Anthony Parish, Louisiana 73506
Name and Address of Owner	Clearwater Oil Company *Regional Field Office* 2451 Mountain Drive Ridgeview, LA 70180 *Corporate Headquarters* 13000 Main Street, Suite 400 Houston, TX 77077

1.2 Contact Information

The designated person accountable for overall oil spill prevention and response at the facility, also referred to as the facility's "Response Coordinator" (RC), is the Field Operations Manager, Bill Laurier. 24-hour contact information is provided in Table 1-1.

Personnel from Avonlea Services Inc. ("Avonlea") provide operations (pumper/gauger) support activities to Clearwater field personnel, including performing informal daily examinations of the facility equipment, as described in Section 3.4 of this SPCC Plan. Avonlea personnel regularly visit the facility to record production levels and perform other maintenance/inspection activities as requested by the Clearwater Field Operations Manager. Key contacts for Avonlea are included in Table 1-1.

Table 1-1: Facility contact information

Name	Title	Telephone	Address
Lester Pearson	Vice-President of Operations Clearwater Oil Co.	(555)-289-4500	13000 Main Street, Suite 400 Houston, TX 77077
Carol Campbell	Regional Director of Operations Clearwater Oil Co.	(405) 831-6320 (office) (405) 831-2262 (cell)	2451 Mountain Drive Ridgeview, LA 70180
Bill Laurier	Field Operations Manager Clearwater Oil Co.	(405) 831-6322 (office) (405) 829-4051 (cell)	2451 Mountain Drive Ridgeview, LA 70180
Joe Clark	Field Supervisor Avonlea Services, Inc.	(406) 545-2285 (office) (406) 549-9087 (cell)	786 Cherry Creek Road Avonlea, LA 70180
William Mackenzie	Pumper Avonlea Services, Inc.	(406) 549-9087 (cell)	786 Cherry Creek Road Avonlea, LA 70180

1.3 Facility Layout Diagram

Appendix A, at the end of this Plan, shows a general site plan for the facility. The site plan shows the site topography and the location of the facility relative to waterways, roads, and inhabited areas. Appendix A also includes a detailed facility diagram that shows the wells, flowlines, tank battery, and transfer areas for the facility. The diagram shows the location, capacity, and contents of all oil storage containers greater than 55 gallons in capacity.

1.4 Facility Location and Operations

Clearwater owns and operates the Big Bear Lease No. 2 production facility, which is located approximately six miles north of Madison, St. Anthony Parish, Louisiana (see Figure A-1 in Appendix A). The site is accessed through a private dirt/gravel road off Route 417.

As illustrated in Figure A-2 in Appendix A, the facility is comprised of five main areas: Well A, Well B, the saltwater disposal well, flowlines, and a tank battery. The tank battery includes three 400-barrel (bbl) oil storage tanks, one 500-bbl produced water tank, one 500-bbl gun barrel, and associated flowlines and piping.

The production facility is generally unmanned. Clearwater's field office is located 25 miles from the site, at 2541 Mountain Drive, Ridgeview, Louisiana. Field operations personnel from Clearwater, or pumpers acting as contractors to Clearwater visit the facility daily (2-4 hours each day) to record production rates and ensure the proper functioning of wellhead equipment and pumpjacks, storage tanks, flowlines, and separation vessels. This includes performing equipment inspections and maintenance as needed.

The facility produces an average of 30 bbl (1,260 gallons) of crude oil (approximately 40 API gravity) and 140 bbl (5,880 gallons) of produced water each day. The produced water tank contains an oil/produced water mixture. It is subject to 40 CFR part 112 and is covered by this SPCC Plan.

1.5 Oil Storage and Handling

1.5.1 Production Equipment

Oil storage at the facility consists of one (1) 500-bbl gun barrel, three (3) 400-bbl aboveground storage tanks, one (1) 500-bbl produced water tank, and associated piping, as summarized in Table 1-2. The total oil capacity at this facility is 2,200 bbl (92,400 gallons).

All oil storage tanks are shop-built and meet the American Petroleum Institute (API) tank construction standard. Their design and construction are compatible with the oil they contain and the temperature and pressure conditions of storage. Tanks storing crude or produced oil (#1 through #4) are constructed of welded steel following API-12F *Shop Welded Tanks for Storage of Production Liquids* specifications. Steel tanks are coated to minimize corrosion. Tank holding produced water (#5) constructed of fiberglass following API-12P *Fiberglass Reinforced Plastic Tanks* specifications.

Other production equipment present at the facility include the pumpjacks at each well and water pumps for transfer of saltwater to the injection well. These store a minimal amount of lubricating oil (less than 55 gallons). Lubricating oil and other substances, such as solvents and chemicals for downhole treatment, are also stored at the facility, but in quantities below the 55-gallon threshold for SPCC applicability. Table 1-2 lists all oil containers present at the facility with capacity of 55 gallons or more.

Table 1-2: Characteristics of oil containers

ID	Type	Construction	Primary Content	Capacity (barrels)	Capacity (gallons)
#1	Gun barrel	Steel	Oil	500	21,000
#2	AST	Steel	Oil	400	16,800
#3	AST	Steel	Oil	400	16,800
#4	AST	Steel	Oil	400	16,800
#5	AST	Fiberglass	Produced water and oil mixture	500	21,000
			TOTAL	2,200	92,400

1.5.2 Transfer Activities

Wells A and B produce crude oil, produced water (saltwater), and small amounts of natural gas. The oil and water are produced through the tubing, while the natural gas is produced through the casing. Well liquids are then routed via 2-inch steel flowlines to the gun barrel tank for separation, while the gas is sent to a flare. Produced saltwater is routed from the gun barrel to the 500-bbl saltwater storage tank first, then is pumped through flowlines to the saltwater disposal well where it is injected. The disposal well is located approximately 2,000 ft to the west of the tank battery. The crude oil is sent to the three 400-bbl (16,800-gallon) oil storage tanks.

Crude oil from the lease is purchased by Clearwater's crude oil purchaser and transported from the facility by the purchaser's tanker truck. Although daily well production rates may vary, enough crude is produced and stored for approximately one 180-bbl (7,560-gallon) load of oil to be picked up weekly by the transporter. The largest tanker truck visiting the facility has a total capacity of 210 bbl (8,820 gallons). Tanker trucks come to the facility only to transfer crude oil and do not remain at the facility. All transfer operations are attended by the trucker or by field operations personnel and meet the minimum requirements of the U.S. Department of Transportation Hazardous Materials Regulations. Appendix B to this Plan summarizes the Tank Truck Loading Procedure at this facility.

Produced saltwater is pumped via transfer pumps from the saltwater tank to the saltwater disposal well, located approximately 2,000 feet west of the facility, by 2-inch PVC flowlines (FLSW). The disposal well meets all requirements of the Underground Injection Control (UIC) program (40 CFR parts 144-148).

1.6 Proximity to Navigable Waters

The facility is located within the Mines River watershed, approximately half a mile to the west of Big Bear Creek, and six miles North of the Mines River. The wells and tank battery are situated on relatively level ground that slopes in a general southeastern direction. The site plan in Figure A-1 in Appendix A shows the location of the facility relative to nearby waterways. The facility diagram included in Figure A-2 in Appendix A indicates the general direction of drainage. In the event of an uncontrolled discharge from the wells, flowlines, or the tank battery areas, oil would follow the natural topography of the site and flow into Big Bear Creek. Big Bear Creek meets with the Mines River to the south just before the town of Madison. The River then flows in a general easterly direction following Route 101.

1.7 Conformance with Applicable State and Local Requirements [112.7(j)]

The SPCC regulation at 40 CFR part 112 is more stringent than requirements from the state of Louisiana for this type of facility. This SPCC Plan was written to conform with 40 CFR part 112 requirements. The facility thereby conforms with general requirements for oil pollution facilities in Louisiana. All discharge notifications are made in compliance with local, state, and federal requirements.

PART II. SPILL RESPONSE AND REPORTING

40 CFR 112.7

2.1 Discharge Discovery and Reporting [112.7(a)(3)]

Several individuals and organizations must be contacted in the event of an oil discharge. The Field Operations Manager is responsible for ensuring that all required discharge notifications have been made. All discharges should be reported to the Field Operations Manager. The summary table included in Appendix F to this SPCC Plan provides a list of agencies to be contacted under different circumstances. Discharges would typically be discovered during the inspections conducted at the facility in accordance with procedures set forth in Section 3.4.1 of this SPCC Plan, Table 3-3 and Table 3-4, and on the checklist of Appendix C. The Form included in Appendix F of this Plan summarizes the information that must be provided when reporting a discharge, including contact lists and phone numbers.

2.1.1 Verbal Notification Requirements (Local, State, and Federal (40 CFR part 110))

Any unauthorized discharge into air, land or water must be reported immediately to the State Police and the Emergency Planning Commission as soon as the discharge is detected.

For any discharge that reaches navigable waters, or threatens to reach navigable waters, *immediate* notification must be made to the National Response Center Hotline (800-424-8802) and to the Environmental Protection Agency.

In the event of a discharge that threatens to result in an emergency condition, facility field personnel must verbally notify the Louisiana Emergency Hazardous Materials Hotline (225-925-6595) immediately, and in no case later than *within one (1) hour* of the discovery of the discharge. An emergency condition is any condition that could reasonably be expected to endanger the health and safety of the public; cause significant adverse impact to the land, water, or air environment; or cause severe damage to property. This notification must be made regardless of the amount of the discharge.

In the event of a discharge that does not present an emergency situation, verbal notification must be made to the Office of Environmental Compliance (by telephone at 225-763-3908 during office hours or 225-342-1234 after hours, weekends, and holidays; or by e-mail utilizing the Incident Report Form and procedures found at www.deq.state.la.us/surveillance) *within twenty-four (24) hours* of the discovery of the discharge.

2.1.2 Written Notification Requirements (State and Federal (40 CFR part 112))

A written notification will be made to EPA for any single discharge of oil to a navigable waters or adjoining shoreline waterway of more than 1,000 gallons, or for two discharges of 1 bbl (42 gallons) of oil to a waterway in any 12-month period. This written notification must be made within 60 days of the qualifying discharge, and a copy will be sent to the Louisiana Department of Environmental Quality (DEQ), which is the state agency in charge of oil pollution control

activities. This reporting requirement is separate and in addition to reporting under 40 CFR part 110 discussed above.

For any discharge reported verbally, a written notification must also be sent to the DEQ and to the St. Anthony's Parish Local Emergency Planning Committee (LEPC), both within five (5) days of the qualifying discharge.

A written notification to the State Emergency Response Commission or LEPC is required for a discharge of 100 lbs or more beyond the confines of the facility (equivalent to 2 mcf of natural gas, or 13 gallons of oil) within five (5) days of the qualifying discharge.

2.1.3 Submission of SPCC Information

Whenever the facility experiences a discharge into navigable waters of more than 1,000 gallons, or two discharges of 42 gallons or more within a 12-month period, Clearwater will provide information in writing to the EPA Region 6 office within 60 days of a qualifying discharge as described above. The required information is described in Appendix F of this SPCC Plan.

2.2 Spill Response Materials

Boom, sorbent, and other spill response materials are stored in the shed next to the loading area and are accessible by Clearwater and Avonlea personnel. The response equipment inventory for the facility includes:

(4)	Empty 55-gallons drums to hold contaminated material
(3)	50-ft absorbent socks
(4)	10-ft sections of hard skirted deployment boom
(2)	50-ft floating booms
(200 pounds)	"Oil-dry" loose absorbent material
(4 boxes)	2 ft x 3 ft absorbent pads
(3 boxes)	Nitrile gloves
(3 boxes)	Neoprene gloves
(6 pairs)	Vinyl/PVC pull-on overboots
(3)	Non-sparking shovels
(3)	Brooms
(20)	Sand bags
(1)	Combustible Gas Indicator with H_2S detection capabilities

Additional equipment and material are also kept at the field office. The inventory is checked monthly by Clearwater field operations personnel to ensure that used material is replenished. Supplies and equipment may be ordered from:

(1) Rocky Mountain Equipment Co. (800) 959-3000
(2) Quick Sorbent (800) 857-4650.

2.3 Spill Mitigation Procedures

The following is a summary of actions that must be taken in the event of a discharge. It summarizes the distribution of responsibilities among individuals and describes procedures to follow in the event of a discharge.

A complete outline of actions to be performed in the event of a discharge from flowlines reaching or threatening to reach navigable waters is included in the facility Contingency Plan (see Appendix I of this SPCC Plan).

Reminder: *In the event of a discharge originating from Flowline A or Flowline B, facility personnel must immediately implement the Oil Spill Contingency Plan. The Oil Spill Contingency Plan discusses the additional procedures that must be followed to respond to a discharge of oil to navigable waters or adjoining shorelines.*

In the event of a discharge, Clearwater or contractor field personnel and the Field Operations Manager shall be responsible for the following:

2.3.1 Shut Off Ignition Sources

Field personnel must shut off all ignition sources, including motors, electrical circuits, and open flames. See Appendix G for more information about shut-off procedures.

2.3.2 Stop Oil Flow

Field personnel should determine the source of the discharge, and if safe to do so, immediately shut off the source of the discharge. Shut in the well(s) if necessary.

2.3.3 Stop the Spread of Oil and Call the Field Operations Manager

If safe to do so, field personnel must use resources available at the facility (see spill response material and equipment listed in Section 2.2) to stop the spilled material from spreading. Measures that may be implemented, depending on the location and size of the discharge, include placing sorbent material or other barriers in the path of the discharge (e.g., sand bags), or constructing earthen berms or trenches.

In the event of a significant discharge, field personnel must immediately contact the Field Operations Manager, who may obtain assistance from authorized company contractors and direct the response and cleanup activities. Should a discharge reach Big Bear Creek, only physical response and countermeasures should be employed, such as the construction of underflow dams, installation of hard boom and sorbent boom, use of sorbent pads, and use of vacuum trucks to recover oil and oily water from the creek. If water flow is low in the creek, construction of an underflow dam downstream and ahead of the spill flow may be advantageous. Sorbent material and/or boom should be placed immediately downstream of the dam to recover any sheen from the water. If water flow is normal in the creek, floating booms and sorbent boom will be deployed. Vacuum trucks will then be utilized to remove oil and oily

water at dams and other access points. Crews should remove oiled vegetation and debris from the creek banks and place them in bags for later disposal. After removal of contaminated vegetation, creek banks should be flushed with water to remove free oil and help it flow down to dams and other access points where it can be recovered by vacuum truck. At no time shall any surfactants, dispersants, or other chemicals be used to remove oil from the creek.

2.3.4 Gather Spill Information

The Field Operations Manager will ensure that the *Discharge Notification Form* is filled out and that notifications have been made to the appropriate authorities. The Field Operations Manager may ask for assistance in gathering the spill information on the *Discharge Notification Form* (Appendix F) of this Plan:

- Reporter's name
- Exact location of the spill
- Date and time of spill discovery
- Material spilled (e.g., oil, produced water containing a reportable quantity of oil)
- Total volume spilled and total volume reaching or threatening navigable waters or adjoining shorelines
- Weather conditions
- Source of spill
- Actions being taken to stop, remove, and mitigate the effects of the discharge
- Whether an evacuation may be needed
- Spill impacts (injuries; damage; environmental media, e.g., air, waterway, groundwater)
- Names of individuals and/or organizations who have also been contacted

2.3.5 Notify Agencies Verbally

Some notifications must be completed *immediately* upon discovering the discharge. It is important to immediately contact the Field Operations Manager so that timely notifications can be made. If the Field Operations Manager is not available, or the Field Operations Manager requests it, field personnel must designate one person to begin notification. Section 2.1 of this Plan describes the required notifications to government agencies. The Notification List is included in Appendix F of this SPCC Plan. The Field Operations Manager must also ensure that written notifications, if needed, are submitted to the appropriate agencies.

2.4 Disposal Plan

The cleanup contractor will handle the disposal of any recovered product, contaminated soil, contaminated materials and equipment, decontamination solutions, sorbents, and spent chemicals collected during a response to a discharge incident.

Any recovered product that can be recycled will be placed into the gun barrel tank to be separated and recycled. Any recovered product not deemed suitable for on-site recycling will be disposed of with the rest of the waste collected during the response efforts.

If the facility responds to a discharge without involvement of a cleanup contractor, Clearwater will contract a licensed transportation/disposal company to dispose of waste according to regulatory requirements. The Field Operations Manager will characterize the waste and arrange for the use of certified waste containers.

All facility personnel handling hazardous wastes must have received both the initial 40-hour and annual 8-hour refresher training in the Hazardous Waste Operations and Emergency Response Standard (HAZWOPER) of the Occupational Health and Safety Administration (OSHA). This training is included as part of the initial training received by all field personnel. Training records and certificates are kept at the field office.

PART III. SPILL PREVENTION, CONTROL, AND COUNTERMEASURE PROVISIONS

40 CFR 112.7 and 112.9

3.1 Potential Discharge Volume and Direction of Flow [112.7(b)] and Containment [112.7(a)(3)(iii)]

Table 3-1, below, summarizes potential oil discharge scenarios. If unimpeded, oil would follow the site topography and reach Big Bear Creek.

Table 3-1: Potential discharge volume and direction of flow

Source	Type of failure	Maximum Volume (gal)	Maximum Discharge Rate (gal/hr)	Direction of Flow	Containment
Tank Battery					
Crude Oil Storage Tank	Rupture due to lightning strike, seam failure	16,800	16,800	Southeast towards Big Bear Creek.	Containment berm
	Leak at manway, valves	24	1	Southeast towards Big Bear Creek.	
	Overflow (1 day's production)	1,260	53	Southeast towards Big Bear Creek.	
Gun barrel	Rupture due to lightning strike, seam failure	21,000	21,000	Southeast towards Big Bear Creek.	Containment berm
	Leak at manway, valves	42	2	Southeast towards Big Bear Creek.	
	Overflow (1 day's production)	7,140	298	Southeast towards Big Bear Creek.	Containment berm
Flowlines and Piping					
Flowlines and Piping on Storage Tanks and Gun Barrel	Rupture/failure due to corrosion	3,570	148	Southeast towards Big Bear Creek.	Containment berm
	Pinhole leak, or leak at connection	48	2	Southeast towards Big Bear Creek.	
Flowlines and Piping associated with wells	Rupture/failure due to corrosion	3,570	148	Southeast towards Big Bear Creek.	None; See Oil Spill Contingency Plan

Source	Type of failure	Maximum Volume (gal)	Maximum Discharge Rate (gal/hr)	Direction of Flow	Containment
	Pinhole leak, or leak at connection	48	2	Southeast towards Big Bear Creek.	None; See Oil Spill Contingency Plan
Wells					
Polished rod stuffing box, valves, fittings, gauges	Leak	24	1	Southeast towards Big Bear Creek.	Well pad
Saltwater Disposal					
Piping/hoses, pumps, valves	Leak	24	1	Southeast towards Big Bear Creek.	Containment berm
Transfers and Loading Operations					
Transport truck loading hose	Rupture	84	84	Southeast towards Big Bear Creek.	Downslope berm
Offload line, connection	Leak	42	1	Southeast towards Big Bear Creek.	Downslope berm
Tank truck	Over-topping while loading	1,680	1,680	Southeast towards Big Bear Creek.	Drainage ditch
Transfer valve	Rupture, leak of valve packing	3	3	Southeast towards Big Bear Creek.	Load line container, curb

3.2 Containment and Diversionary Structures [112.7(c) and 112.7(a)(3)(iii)]

The facility is configured to minimize the likelihood of a discharge reaching navigable waters. The following measures are provided:

- Secondary containment for the oil storage tanks, saltwater tank (which may have small amounts of oil), and gun barrel is provided by a 60 ft x 40 ft x 2.5 ft earthen berm that provides a total containment volume of 867 barrels (36,423 gallons), as described in Section 3.2.2 below. The berm is constructed of native soils and heavy clay that have been compacted, then covered with gravel. A clay layer in the shallow subsurface exists naturally and will stop any spilled oil from seeping to deeper groundwater.

- The tank truck loading area is flat but gently slopes to the southeast, where a crescent-shaped, open berm has been placed to catch any potential spills from tanker transport trucks. The bermed area provides a catchment basin of 40 barrels (1,680 gallons), the maximum expected amount of a spill from the tanker due to overtopping of the truck during loading. In addition, the end of the load line is equipped with a load line drip bucket designed to prevent small discharges that may occur when disconnecting the hose.

- Booms, sorbents, shovels, and other discharge response materials are stored in a shed located in close proximity to the loading area. This material is sufficient to contain small discharges (up to approximately 200 gallons).

These measures are described in more details in the following sections.

3.2.1 Oil Production Facility Drainage [112.9(b)]

Facility drainage in the production/separation area but outside containment berms is designed to flow into drainage ditches located on the eastern and southern boundaries of the site. These ditches usually run dry. The ditches are visually examined by facility personnel on a daily basis during routine facility rounds, during formal monthly inspections, and after rain events, to detect any discoloration or staining that would indicate the presence of oil from small leaks within the facility. Any accumulation of oil is promptly removed and disposed off site. Formal monthly inspections are documented.

Discharges from ASTs are restrained by the secondary containment berm, as described in Section 3.2.2 of this Plan. Discharges occurring during transfer operations will be contained at each well by the rock pad or will flow into the drainage ditch located at the facility.

3.2.2 Secondary Containment for Bulk Storage Containers [112.9(c)(2)]

In order to further minimize the potential for a discharge to navigable waters, bulk storage containers such as all tank battery, separation, and treating equipment are placed inside a 2.5-ft tall earthen berm (fire wall). The berm capacity exceeds the SPCC and Louisiana requirements. It provides secondary containment sufficient for the size of the largest tank, plus at least 1 ft of freeboard to contain precipitation. This secondary containment capacity is equivalent to 173 percent of the capacity of the largest tank within the containment area (500 barrels) and exceeds the 10 percent freeboard recommended by API for firewalls around production tanks (API-12R1). The amount of freeboard also exceeds the amount of precipitation anticipated at this facility, which is estimated to average 3.5 inches for a 24-hour, 25-year storm, based on data from the nearby Ridgeview Regional Airport. Details of the berm capacity calculation are provided in Table 3-2.

Table 3-2: Berm capacity calculations

Berm Capacity	
Berm height	2.5 ft
Berm dimensions	60 ft x 40 ft = 2,400 ft^2
Tank footprint	4 tanks @ 12 ft dia. each = 4 x (π $12^2/4$) = 452 ft^2
Net volume	2.5 ft x (2,400 - 452) = 4,869 ft^3 = 36,423 gallons
Ratio to largest tank	36,423 / 21,000 = 173%
Corresponding Amount of Freeboard	
100% of tank volume	21,000 gallons = 2,807 ft^3
Net area (minus tank footprint)	2,400 ft^2 - 452 ft^2 = 1,948 ft^2
Minimum berm height for 100% of tank volume	2,807 ft^3 / 1,948 ft^2 = 1.44 ft
Freeboard	2.5 ft - 1.44 ft = 1.06 ft

The floor and walls of the berm are constructed of compacted earth with a layer of clay that ensures that the berm is able to contain the potential release of oil from the storage tanks until the discharge can be detected and addressed by field operations personnel. Facility personnel inspect the berm daily for the presence of oil. The sides of the berm are capped with gravel to minimize erosion.

The berm is equipped with a manual valve of open-and-closed design. The valve is used to drain the berm and is normally kept closed, except when draining water accumulation within the berm. Drainage from the berm flows into the drainage ditch to the south of the production/ separation area. All water is closely inspected by field operations personnel (who are the persons providing “responsible supervision”) prior to draining water accumulation to ensure that no free oil is present (i.e., there is no sheen or discoloration upon the surface, or a sludge or emulsion deposit beneath the surface of the water). The bypass valve for the containment structure is opened and resealed following drainage under the responsible supervision of field operations personnel. Free oil is promptly removed and disposed of in accordance with waste regulations. Drainage events are recorded on the form provided in Appendix D, including the time, date, and name of the employee who performed the drainage. The records are maintained with this SPCC Plan at the Ridgeview field office for a period of at least three years.

3.2.3 Practicability of Secondary Containment [112.7(d)]

Flowlines adjacent to the production equipment and storage tanks are located within the berm, and therefore have secondary containment. Aboveground flowlines that go from the wells to the production equipment and buried flowlines, however, lack adequate secondary containment.

The installation of double-wall piping, berms, or other permanent structures (e.g., remote impoundment) are impracticable at this facility due to the long distances involved and physical

and road/fenceline right-of-way constraints. Additionally, such permanent structures would create land erosion and access problems for the landowner's farming operations and current uses of the land (e.g., agricultural production, animal grazing).

Other measures listed under 40 CFR 112.7(c) such as the use of sorbents are also impracticable as means of secondary containment since the volumes involved may exceed the sorbent capacity and the facility is attended for only a few hours each day.

Because secondary containment for flowlines outside of the tank battery is impracticable, Clearwater has provided with this Plan additional elements required under 40 CFR 112.7(d), including:

- A written commitment of manpower, equipment, and materials required to expeditiously control and remove any quantity of oil discharged that may be harmful (see Appendix H).
- An Oil Spill Contingency Plan following the provisions of 40 CFR 109 (see Appendix I).

3.3 Other Spill Prevention Measures

3.3.1 Bulk Storage Containers Overflow Prevention [112.9(c)(4)]

The tank battery is designed with a fail-safe system to prevent discharge, as follows:

- The capacity of the oil storage tanks is sufficient to ensure that oil storage is adequate in the event where facility personnel are unable to perform the daily visit to unload the tanks or the pumper is delayed in stopping production. The maximum capacity of the wells linked to the tank battery is approximately 600 barrels per day. The oil tanks are sized to provide sufficient storage for at least two days.

- The tanks are connected with overflow equalizing lines to ensure that a full tank can overflow to an adjacent tank.

3.3.2 Transfer Operations and Saltwater Disposal System [112.9(d)]

All aboveground valves and piping associated with transfer operations are inspected daily by the pumper and/or tank truck driver, as described in Section 3.4 of this Plan. The inspection procedure includes observing flange joints, valve glands and bodies, drip pans, and pipe supports. The conditions of the pumping well polish rod stuffing boxes, and bleeder and gauge valves, are inspected monthly.

Components of the produced water disposal system are inspected on a monthly basis by field operation personnel as described in Section 3.4 and following the checklist provided in Appendix C of this SPCC Plan. This includes the pumps and motors for working condition and

leaks, hoses, valves, flowlines, and the saltwater injection wellhead. Maintenance and operation of the well itself and the downhole injection comply with EPA's and the state's Underground Injection Control (UIC) rules and regulations (40 CFR parts 144-148).

3.4 Inspections, Tests, and Records [112.7(e)]

This Plan outlines procedures for inspecting the facility equipment in accordance with SPCC requirements. Records of inspections performed as described in this Plan and signed by the appropriate supervisor are a part of this Plan, and are maintained with this Plan at the Ridgeview field office for a minimum of three years. The reports include a description of the inspection procedure, the date of inspection, whether drainage of accumulated rainwater was required, and the inspector's signature.

The program established in this SPCC Plan for regular inspection of all oil storage tanks and related production and transfer equipment follows the American Petroleum Institute's *Recommended Practice for Setting Maintenance, Inspection, Operation, and Repair of Tanks in Production Service* (API RP 12R1, Fifth Edition, August 1997). Each container is inspected monthly by field operation personnel as described in this Plan section and following the checklist provided in Appendix C of this SPCC Plan. The monthly inspection is aimed at identifying signs of deterioration and maintenance needs, including the foundation and support of each container. Any leak from tank seams, gaskets, rivets, and bolts is promptly corrected.

This Plan also describes provisions for monitoring the integrity of flowlines through a combination of monthly visual inspections and periodic pressure testing or through the use of an alternate technology. The latter element is particularly important for this facility since flowlines do not have adequate secondary containment.

The inspection program is comprised of informal daily examinations, monthly scheduled inspections, and periodic condition inspections. Additional inspections and/or examinations are performed whenever an operation alert, malfunction, shell or deck leak, or potential bottom leak is reported following a scheduled examination. Written examination/inspection procedures and monthly examination/inspection reports are signed by the field inspector and are maintained at the field office for a period of at least three years.

3.4.1 Daily Examinations

The facility is visited daily by field operations personnel. The daily visual examination consists of a walk through of the tank battery and around the wells. Field operations personnel check the wells and production equipment for leaks and proper operation. They examine all aboveground valves, polished rod stuffing boxes, wellheads, fittings, gauges, and flowline piping at the wellhead. Personnel inspect pumps to verify proper function and check for damage and leakage. They look for accumulation of water within the tank battery berms and verify the condition and position of valves. The storage tanks are gauged every day. A daily production report is maintained. All malfunctions, improper operation of equipment, evidence of leakage,

stained or discolored soil, etc. are logged and communicated to the Clearwater Field Operations Manager.

Table 3-3: Scope of daily examinations

Facility Area	Item	Observations
Storage Tanks (Oil and Produced water)	Leaks	Tank liquid level gauged Drip marks, leaks from weld seams, base of tank Puddles containing spilled or leak material Corrosion, especially at base (pitting, flaking) Cracks in metal Excessive soil or vegetation buildup against base
	Foundation problems	Cracks Puddles containing spilled or leaked material Settling Gaps at base
	Flowlines problems	Evidence of leaks, especially at connections/collars Corrosion (pitting, flaking) Settling Evidence of stored material seepage from valves or seals
Wells	Leak	Evidence of oil seepage from pumping rod stuffing boxes, wellhead and wellhead flowlines, valves, gauges
SW Pumps	Leaks	Leaks at seals, flowlines, valves, hoses Puddles containing spilled or leaked material Corrosion

3.4.2 Monthly Inspections

Table 3-4 summarizes the scope of monthly inspections performed by field personnel.

The monthly inspection covers the wellheads, flowlines, and all processing equipment. It also includes verifying the proper functioning of all detection devices, including high-level sensors on oil storage tanks, heater treater, and separators. Storage tanks are inspected for signs of deterioration, leaks, or accumulation of oil inside the containment area, or other signs that maintenance or repairs are needed. The secondary containment area is checked for proper drainage, general conditions, evidence of oil, or signs of leakage. The monthly inspection also involves visually inspecting all aboveground valves and pipelines and noting the general condition of items such as transfer hoses, flange joints, expansion joints, valve glands and bodies, catch pans, pipeline supports, pumping well pumping rod stuffing boxes, bleeder and gauge valves, locking of valves, and metal surfaces.

The checklist provided in Appendix C is used during monthly inspections. These inspections are performed in accordance with written procedures such as API standards (e.g., API RP 12R1), engineering specifications, and maintenance schedule developed by the equipment manufacturers.

All safety devices are tested quarterly by a third party inspector. The tests are recorded and the results are maintained with this Plan at Clearwater's field office. Testing of the safety devices is conducted in accordance with guidelines API RP-14C published by the American Petroleum Institute, or in accordance with instructions from the device's manufacturer. Written test procedures are kept at the offices of the third party testing company and are available upon request.

Twice a year, facility personnel drive to the pre-established response staging areas located at three different points along Big Bear Creek (see Oil Spill Contingency Plan in Appendix I) to ensure that the dirt/gravel roads are accessible using field vehicles and that the Oil Spill Contingency Plan can be implemented in the event of a discharge from flowlines reaching the Creek.

Table 3-4: Scope of monthly inspections

Facility Area	Equipment	Inspection Item
Tank Battery	Storage tanks	Leakage, gaskets, hatches Tank liquid level checked Tank welds in good condition Vacuum vents Overflow lines Piping, valves, and bull plugs Corrosion, paint condition Pressure / level safety devices* Emergency shut-down system(s)* Pressure relief valves*
	Area	Berm and curbing Presence of contaminated/stained soil Excessive vegetation Equipment protectors and signs Engine drip pans and sumps General housekeeping
Truck Loading	Offload lines, drip pans, valves, catchment berm	Valve closed and in good condition Cap or bull plug at end of offload line/connection Sign of oil or standing water in drip pan(s) Sign of oil or standing water in catchment berm Sign of oil in surrounding area
	Production equipment	Gauges (pressure, temperature, and liquid level) Pressure / level safety devices* Emergency shut-down system(s)* Pressure relief valves*
Wells (including saltwater disposal well)	Area	Spills and leaks (e.g., stuffing box) Equipment protectors and signs General housekeeping

Facility Area	Equipment	Inspection Item
Leasehold area between wells and Tank Battery	Flowlines	Flowline between the well and tank battery/gun barrel Exposed line of buried piping Valves (condition of, whether locked or sealed) Evidence of leaks and/or damage, especially at connections/collars Corrosion (pitting, flaking) Pipe supports
	Road and Field Ditches	Evidence/puddles of crude oil and/or produced water
Other	Chemicals, Fuels and Lube Oils	Storage conditions
Response staging areas	Area	Road practicable by field vehicle Area clear of excessive vegetation
* Tested quarterly by third party inspection company.		

3.4.3 Periodic Condition Inspection of Bulk Storage Containers

A condition inspection of bulk storage containers is performed by a qualified inspector according to the schedule and scope specified in API RP 12R1. The schedule is determined based on the corrosion rate; with the first inspection performed no more than 15 years after the tank construction, as detailed in Table 3-5.

Three bulk storage containers installed at this facility were moved from another facility decommissioned by Clearwater. These bulk storage containers were leak tested after relocation to the facility.

Table 3-5: Schedule of periodic condition inspection of bulk storage containers

Tank	Year Built	Last Inspection	Next inspection by
#1	1983	11/5/1998	11/5/2008*
#2	2002	None	First inspection to be performed by 12/31/2017*
#3	1995	None	First inspection to be performed by 12/31/2010*
#4	2002	None	First inspection to be performed by 12/31/2017*
#5	1991	None	First inspection to be performed by 12/31/2006*

* Dates for subsequent external inspections must follow the recommendations of the certified inspector, not to exceed three-quarters of the predicted shell/roof deck corrosion rate life, or maximum of 15 years.

3.4.4 Brittle Fracture Evaluation [112.7(i)]

At the present time, none of the bulk storage containers at this site was field-erected, and therefore no brittle fracture evaluation is required.

3.4.5 Flowline Maintenance Program [112.9(d)(3)]

Because the facility is relying on a contingency plan to address discharges, the flowline maintenance program is specifically implemented to maintain the integrity of the primary container (in this case piping) to minimize releases of oil from this part of the production facility. The facility's gathering lines and flowlines are configured, inspected monthly for leaks at connections and on each joint, corrosion (pitting, flaking), and maintained to minimize the potential for a discharge as summarized in Table 3-6. Records of integrity inspections, leak tests, and part replacements are kept at the facility for at least three years (integrity test results are kept for ten years).

Table 3-6: Components of flowline maintenance program

Component	Measures/Activities
Configuration	• Well pumps are equipped with low-pressure shut-off systems that detect pressure drops and minimize spill volume in the event of a flowline leak. • Flowlines are identified on facility maps and are marked in the field to facilitate access and inspection by facility personnel. Flowline maps and field tags indicate the location of shutdown devices and valves that may be used to isolate portions of the flowline. • With the exception of a portion of Flowline B under an access road, the flowlines and appurtenances (valves, flange joints, supports) can be visually observed for signs of leakage, deterioration, or other damage.
Inspection	• Lines are visually inspected for leaks and corrosion as part of the monthly rounds by field personnel, as discussed in Section 3.4 above. • The buried portions of Flowline B are coated/wrapped and visually observed for damage or coating condition whenever they are repaired, replaced, or otherwise exposed. • Every five years, flowlines are tested using ultrasonic techniques to determine remaining wall thickness and mechanical integrity. Copies of test results are maintained at the facility for ten years to allow comparison of successive tests.
Maintenance	• Any leak in the flowline or appurtenances is promptly addressed by isolating the damaged portion and repairing or replacing the faulty piece of equipment. Clearwater does not accept pipe clamps and screw-in plugs as forms of repair. • Any portion of a flowline that fails the mechanical integrity test is repaired and retested, or replaced.

3.5 Personnel, Training, and Discharge Prevention Procedures [112.7(f)]

The Field Operations Manager has been designated as the point of contact for all oil discharge prevention and response at this facility.

All Clearwater field personnel receive training on proper handling of oil products and procedures to respond to an oil discharge prior to entering any Clearwater production facility. The training ensures that all facility personnel understand the procedures described in this SPCC Plan and are informed of the requirements under applicable pollution control laws, rules and regulations. The training also covers risks associated with potential exposure to hydrogen sulfide (H_2S) gas.

All Clearwater field personnel also receive an initial 40-hour HAZWOPER training (and 8-hour annual refresher training) as per OSHA standard.

Clearwater ensures that all contractor personnel are familiar with the facility operations, safety procedures, and spill prevention and control procedures described in this Plan prior to working at the facility. All contractors working at the facility receive a copy of this SPCC Plan. Avonlea personnel visiting the facility receive training similar to that provided to Clearwater oil handling employees.

Clearwater management holds briefings with field operations personnel (including contractor personnel as appropriate) at least once a year, as described below.

3.5.1 Spill Prevention Briefing

The Field Operations Manager conducts Spill Prevention Briefings annually to ensure adequate understanding and effective implementation of this SPCC Plan. These briefings highlight and describe known spill events or failures, malfunctioning components, and recently developed precautionary measures. The briefings are conducted in conjunction with the company safety meetings. Sign-in sheets, which include the topics of discussion at each meeting, are maintained with this Plan at Clearwater's field office. A *Discharge Prevention Briefing Log* form is provided in Appendix E to this Plan and is used to document the briefings. The scheduled annual briefing includes a review of Clearwater policies and procedures relating to spill prevention, control, cleanup, and reporting; procedures for routine handling of products (e.g., loading, unloading, transfers); SPCC inspections and spill prevention procedures; spill reporting procedures; spill response; and recovery, disposal, and treatment of spilled material.

Personnel are instructed in operation and maintenance of equipment to prevent the discharge of oil, and in applicable federal, state, and local pollution laws, rules, and regulations. Facility operators and other personnel have an opportunity during the briefings to share recommendations concerning health, safety, and environmental issues encountered during facility operations.

The general outline of the briefings is as follows:

- Responsibilities of personnel and Designated Person Accountable for Spill Prevention;
- Spill prevention regulations and requirements;
- Spill prevention procedures;
- Spill reporting and cleanup procedures;
- History/cause of known spill events;
- Equipment failures and operational issues;
- Recently developed measures/procedures;
- Proper equipment operation and maintenance; and
- Procedures for draining rainwater from berms.

3.5.2 Contractor Instructions

In order that there will be no misunderstanding on joint and respective duties and responsibilities to perform work in a safe manner, contractor personnel also receive instructions on the procedures outlined in this SPCC Plan. The instructions cover the contractor activities such as servicing a well or equipment associated with the well, such as pressure vessels.

All contractual agreements between Clearwater and contractors specifically state:

> Personnel must, at all times, act in a manner to preserve life and property, and prevent pollution of the environment by proper use of the facility's prevention and containment systems to prevent hydrocarbon and hazardous material spills. No pollutant, regardless of the volume, is to be disposed of onto the ground or water, or allowed to drain into the ground or water. Federal regulations impose substantial fines and/or imprisonment for willful pollution of navigable waters. Failure to report accidental pollution at this facility, or elsewhere, can be cause for equally severe penalties to be imposed by federal regulations. To this end, all personnel must comply with every requirement of this SPCC Plan, as well as taking necessary actions to preserve life, and property, and to prevent pollution of the environment. It is the contractor's (or subcontractor's) responsibility to maintain his equipment in good working order and in compliance with this SPCC Plan. The contractor (or subcontractor) is also responsible for the familiarity and compliance of his personnel with this SPCC Plan. Contractor and subcontractor personnel must secure permission from Clearwater's Field Operations Manager before commencing any work on any facility. They must immediately advise the Field Operations Manager of any hazardous or abnormal condition so that the Field Operations Manager can take corrective measures.

APPENDIX A: Facility Diagrams

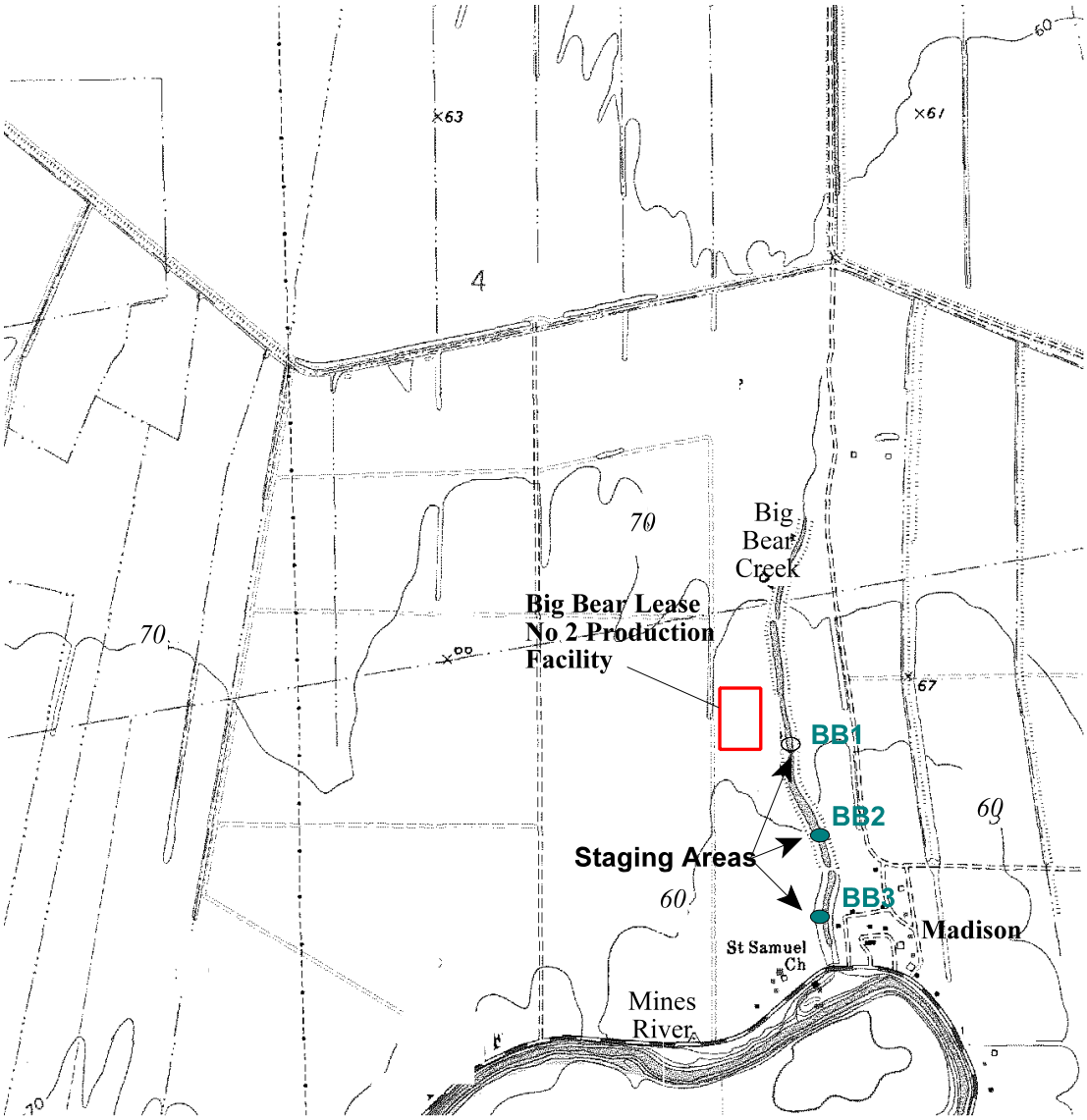


Figure A-1: Site plan.

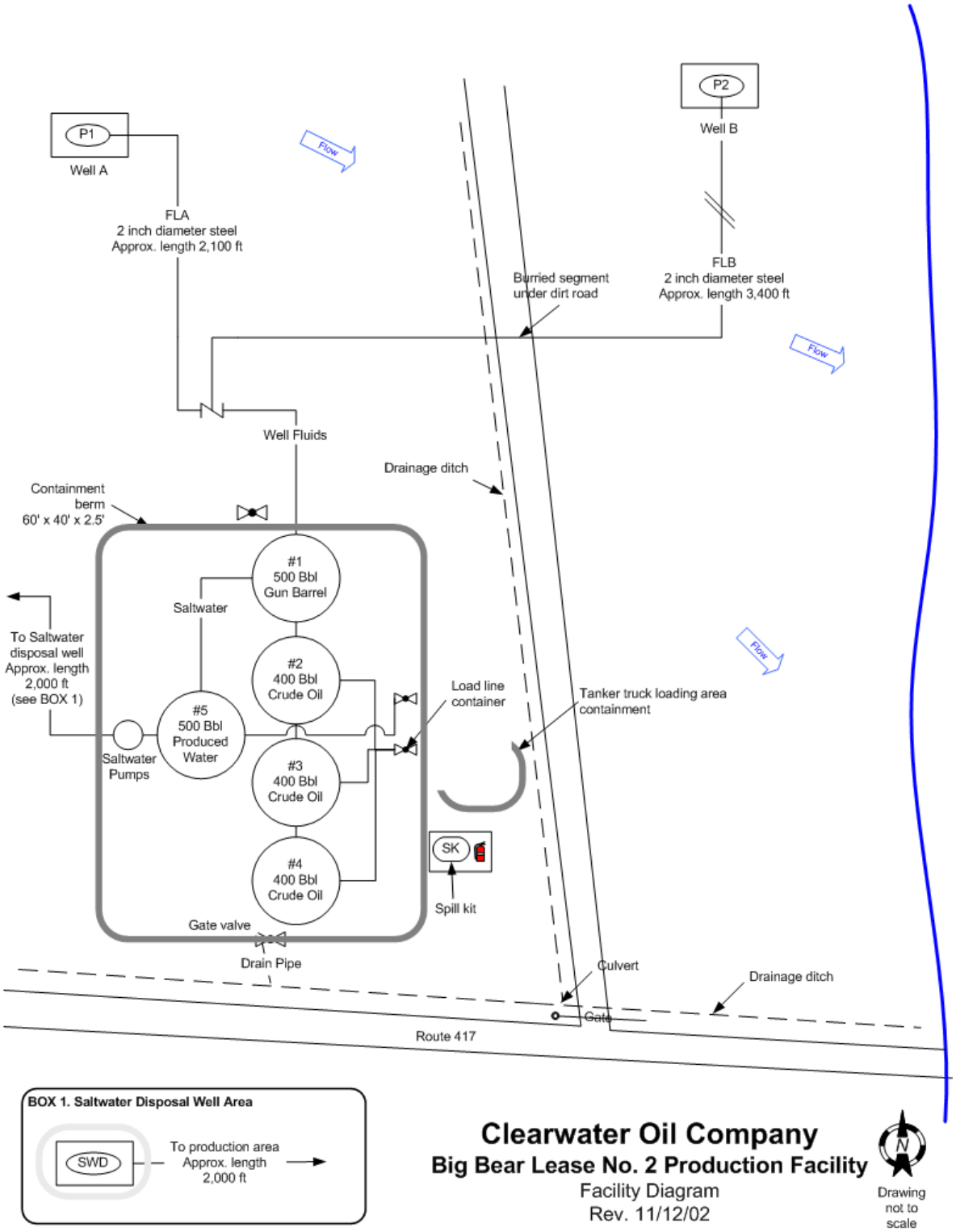


Figure A-2: Production Facility Diagram.

APPENDIX B: Tank Truck Loading Procedures

Loading Tank Truck

Make sure the vehicle tank is properly vented before starting to load or unload. If you are not certain that the trailer is properly vented, you must contact your supervisor and request permission to open the trailer dome before starting to load or unload.

To Load from Storage Tank to Tank Truck

- Attach ground cable or bonding clamp to trailer.
- Use wheel chocks or other similar barrier to prevent premature departure.
- Hook up load hose and open all appropriate valves from storage tank to trailer entry.
- Disengage clutch and place pump in load position.
- Release clutch slowly.
- Adjust throttle to proper engine RPM.
- When trailer is loaded to appropriate level, slow engine speed.
- Close valve to storage tank.
- Loosen loading hose to allow enough air to drain loading hose dry.
- Ensure that drips from the hose drain into the spill bucket at the loading area.
- Disconnect loading hose completely, close load valve, plug and fasten securely.
- Close belly valve on trailer.
- Disconnect ground cable.
- Promptly clean up any spilled oil.
- Inspect lowermost drains and valves of the vehicle for discharges/leaks and ensure that they are tightened, adjusted, or replaced as needed to prevent discharges while vehicle is in transit.

APPENDIX C: Monthly Inspection Checklist

Further description and comments, if needed, should be provided on a separate sheet of paper and attached to this sheet. Any item answered "YES" needs to be promptly reported, repaired, or replaced, as it may result in non-compliance with regulatory requirements. Records are maintained with the SPCC Plan at the Ridgeview field office.

Date: _____ Signature: _____

	Yes	No	Description & Comments (Note tank/equipment ID)
Storage tanks and Separation Equipment			
Tank surfaces show signs of leakage			
Tanks show signs of damage, rust, or deterioration			
Bolts, rivets or seams are damaged			
Aboveground tank supports are deteriorated or buckled			
Aboveground tank foundations have eroded or settled			
Gaskets are leaking			
Level gauges or alarms are inoperative			
Vents are obstructed			
Thief hatch and vent valve does not seal air tight			
Containment berm shows discoloration or stains			
Berm is breached or eroded or has vegetation			
Berm drainage valves are open/broken			
Tank area clear of trash and vegetation			
Equipment protectors, labels, or signs are missing			
Piping/Flowlines and Related Equipment			
Valve seals or gaskets are leaking.			
Pipelines or supports are damaged or deteriorated.			
Buried pipelines are exposed.			
Transfer equipment			
Loading/unloading lines are damaged or deteriorated.			
Connections are not capped or blank-flanged			
Secondary containment is damaged or stained			
Response Kit Inventory			
Discharge response material is missing or damaged or needs replacement			

Additional Remarks (attach sheet as needed):

APPENDIX D: Record of Dike Drainage

This record must be completed when rainwater from diked areas is drained into a storm drain or into an open watercourse, lake, or pond, and bypasses the water treatment system. The bypass valve must normally be sealed in closed position and opened and resealed following drainage under responsible supervision. Records are maintained with the SPCC Plan at the Ridgeview field office.

Date	**Area**	**Presence of Oil**	**Time Started**	**Time Finished**	**Signature**
12/5/2003	Tank battery	No oil	08:00	8:40	William Mackenzie

APPENDIX E: Discharge Prevention Briefing Log

Date	**Type of Briefing**	**Instructor(s)**
12/5/2003	Scheduled refresher. All field personnel.	Helena Berry, Optimal H&S Inc.
11/25/2004	Scheduled refresher. All field personnel.	Bill Laurier

APPENDIX F: Discharge Notification Procedures

Circumstances, instructions, and phone numbers for reporting a discharge to the National Response Center and other federal, state, and local agencies, and to other affected parties, are provided below. They are also posted at the facility in the storage shed containing the discharge response equipment. Note that any discharge to water must be reported immediately to the National Response Center.

Field Operations Manager, Bill Laurier (24 hours) (405) 829-4051

Local Emergency (fire, explosion, or other hazards) 911

Agency / Organization	Agency Contact	Circumstances	When to Notify
Federal Agencies			
National Response Center	1-800-424-8802	Discharge reaching navigable waters.	**Immediately (verbal)**
EPA Region VI (Hotline)	1-800-887-6063		**Immediately (verbal)**
EPA Region VI Regional Administrator	First Interstate Bank Tower at Fountain Place 1445 Ross Avenue, 12th floor, Suite 1200 Dallas TX 75202	Discharge 1,000 gallons or more; or second discharge of 42 gallons or more over a 12-month period.	Written notification within 60 days (see Section 2.1 of this Plan)
State Agencies			
Office of State Police, Transportation and Environmental Safety Section, Hazardous Materials Hotline	225-925-6595 or 1-877-925-6595	1) Injury requiring hospitalization or fatality. 2) Fire, explosion, or other impact that could affect public safety. 3) Release exceeding 24-hour reportable quantity. 4) Impact to areas beyond the facility's confines.	**Immediately (verbal)** Written notification to be made within 5 days.
Office of State Police, Transportation and Environmental Safety Section, Hazardous Materials Hotline	225-925-6595 or 1-877-925-6595	Discharges that pose emergency conditions, regardless of the volume discharged.	**Within 1 hour** of discovery (verbal). Written notification within 7 working days.
Louisiana Department of Environmental Quality, Office of Environmental Compliance	225-763-3908 or 225-342-1234 (after business hours, weekends and holidays)	Discharges that do not pose emergency conditions.	Within 24 hours of discovery (verbal). Written notification within 7 working days.

Agency / Organization	Agency Contact	Circumstances	When to Notify
Local Agencies			
St. Anthony's Parish Emergency Planning Committee	337-828-1960	Any discharge of 100 lbs or more that occur beyond the boundaries of the facility, including to the air.	**Immediately (verbal)** Written notification within 7 days.
Others			
Response/cleanup contractors	EZ Clean (800) 521-3211 Armadillo Oil Removal Co. (214) 566-5588	Any discharge that exceeds the capacity of facility personnel to respond and cleanup.	As needed
Howard Fleming Farm (agricultural irrigation intake)	(405) 235-6893	Any discharge that threatens to affect neighboring properties and irrigation intakes.	As needed

The person reporting the discharge must provide the following information:

- Name, location, organization, and telephone number;
- Name and address of the owner/operator;
- Date and time of the incident;
- Location of the incident;
- Source and cause of discharge;
- Types of material(s) discharged;
- Total quantity of materials discharged;
- Quantity discharged in harmful quantity (to navigable waters or adjoining shorelines);
- Danger or threat posed by the release or discharge;
- Description of all affected media (e.g., water, soil);
- Number and types of injuries (if any) and damaged caused;
- Weather conditions;
- Actions used to stop, remove, and mitigate effects of the discharge;
- Whether an evacuation is needed;
- Name of individuals and/or organizations contacted; and
- Any other information that may help emergency personnel respond to the incident.

Whenever the facility discharges more than 1,000 gallons of oil in a single event, or discharges more than 42 gallons of oil in each of two discharge incidents within a 12-month period, the Manager of Field Operations must provide the following information to the U.S. Environmental Protection Agency's Regional Administrator within 60 days:

- Name of the facility;
- Name of the owner or operator;
- Location of the facility;

- Maximum storage or handling capacity and normal daily throughput;
- Corrective actions and countermeasures taken, including a description of equipment repairs and replacements;
- Description of facility, including maps, flow diagrams, and topographical maps;
- Cause of the discharge(s) to navigable waters, including a failure analysis of the system and subsystems in which the failure occurred;
- Additional preventive measures taken or contemplated to minimize possibility of recurrence; and
- Other pertinent information requested by the Regional Administrator.

Discharge Notification Form

*** Notification must not be delayed if information or individuals are not available.

Facility: Clearwater Oil Company Big Bear Lease No. 2 Production Facility
5800 Route 417, Madison, Louisiana 73506

Description of Discharge		
Date/time	Release date: Release time: Duration:	Discovery date: Discovery time:
Reporting Individual	Name: Tel. #:	
Location of discharge	Latitude: Longitude:	Description:
Equipment source	☐ piping ☐ flowline ☐ well ☐ unknown ☐ stock, flare	Description: Equipment ID:
Product	☐ crude oil ☐ saltwater ☐ other*	* Describe other:
Appearance and description		
Environmental conditions	Wind direction: Wind speed:	Rainfall: Current:
Impacts		
Quantity	Released:	Recovered:
Receiving medium	☐ water** ☐ land ☐ other (describe):	☐ Release confined to company property. ☐ Release outside company property. ** If water, indicate extent and body of water:
Describe circumstances of the release		
Assessment of impacts and remedial actions		
Disposal method for recovered material		
Action taken to prevent incident from reoccurring		
Safety issues	☐ Injuries ☐ Fatalities ☐ Evacuation	

Notifications		
Agency	**Name**	**Date/time reported & Comments**
Company Spill Response Coordinator		
National Response Center 1-800-424-8802		
State police		
Parish Emergency Response Commission		
oil spill removal organization/cleanup contractor		

APPENDIX G: Equipment Shut-off Procedures

Source	Action
Manifold, transfer pumps or hose failure	Shut in the well supplying oil to the tank battery if appropriate. Immediately close the header/manifold or appropriate valve(s). Shut off transfer pumps.
Tank overflow	Shut in the well supplying oil to the tank battery. Close header/manifold or appropriate valve(s)
Tank failure	Shut in the well supplying oil to the tank battery. Close inlet valve to the storage tanks.
Flowline rupture	Shut in the well supplying oil to the flowline. Close nearest valve to the rupture site to top the flow of oil.
Flowline leak	Shut in the well supplying oil to the flowline. Immediately close the nearest valve to stop the flow of oil to the leaking section.
Explosion or fire	Immediately evacuate personnel from the area until the danger is over. Immediately shut in both wells if safe to do so. If possible, close all manifold valves. If the fire is small enough such that it is safe to do so, attempt to extinguish with fire extinguishers available on site.
Equipment failure	Immediately close the nearest valve to stop the flow of oil into the leaking area.

APPENDIX H: Written Commitment of Manpower, Equipment, and Materials

In addition to implementing the preventive measures described in this Plan, Clearwater will also specifically:

- In the event of a discharge:
  - Make available all trained field personnel (three employees) to perform response actions
  - Obtain assistance from an additional three full-time employees from its main operations contractor (Avonlea Services)
  - Collaborate fully with local, state, and federal authorities on response and cleanup operations
- Maintain all on-site oil spill control equipment described in this Plan and in the attached Oil Spill Contingency Plan. The equipment is estimated to contain oil spills of up to 500 gallons.
- Maintain all communications equipment in operating condition at all times.
- Ensure that staging areas to be used in the event of a discharge to Big Bear Creek are accessible by field vehicles.
- Review the adequacy of on-site and third-party response capacity with pre-established response/cleanup contractors on an annual basis and update response/cleanup contractor list as necessary.
- Maintain formal agreements/contracts with response and cleanup contractors who will provide assistance in responding to an oil discharge and/or completing cleanup (see contract agreements maintained separately at the Ridgeview field office and lists of associated equipment and response contractor personnel capabilities).

Authorized Facility Representative:	Bill Laurier
Signature:	*Bill Laurier*
Title:	Field Operations Manager

APPENDIX I: Oil Spill Contingency Plan

The oil spill contingency plan is maintained separately at the Ridgeview field office.

[Refer to the sample Contingency Plan also available from EPA for more information on the content and format of that Plan]

Appendix F: Sample Contingency Plan

DISCLAIMER - APPENDIX F

The sample Contingency Plan in Appendix F is intended to provide examples of contingency planning as a reference when a facility determines that the required secondary containment is impracticable, pursuant to 40 CFR §112.7(d). The sample Contingency Plan presents a variety of scenarios for purposes of illustration only. It is not a template to be adopted by a facility; doing so does not mean that the facility will be in compliance with the SPCC rule requirements for a contingency plan. Nor is the sample plan a template that must be followed in order for the facility to be considered in compliance with the contingency plan requirement.

CLEARWATER OIL COMPANY
BIG BEAR LEASE NO. 2 PRODUCTION FACILITY
OIL SPILL CONTINGENCY PLAN

***NOTE**: Throughout this document, shaded boxes identify relevant sections of 40 CFR part 109 and part 112.*

PART I
Introduction

1.1 Purpose and Scope

This Oil Spill Contingency Plan is prepared in accordance with 40 CFR 112.7(d) to address areas of the facility where secondary containment is impracticable, as documented in the facility Spill Prevention, Control, and Countermeasure (SPCC) Plan.

The purpose of this Oil Spill Contingency Plan ("Contingency Plan") is to define procedures and tactics for responding to discharges of oil into navigable waters or adjoining shorelines of the United States, originating more specifically from flowlines at Clearwater Oil Company ("Clearwater") Big Bear Lease No. 2 Production Facility. The Contingency Plan is implemented whenever a discharge of oil has reached, or threatens, navigable waters or adjoining shorelines.

The objective of procedures described in this Contingency Plan is to protect the public, Clearwater personnel, and other responders during oil discharges. In addition, the Plan is intended to minimize damage to the environment, natural resources, and facility installations from a discharge of oil. This Oil Spill Contingency Plan complements the prevention and control measures presented in the facility's SPCC Plan by addressing areas of the facility that have inadequate secondary containment and impacts that may result from a discharge from these areas. The facility implements a detailed and stringent flowline maintenance program to prevent leaks from the primary system (in this case, piping). Areas lacking adequate containment at the Big Bear Lease No. 2 Production Facility include the flowlines that run between the extraction wells and the tank battery area and between the tank battery area and the saltwater disposal area.

This Oil Spill Contingency Plan follows the content and organization of 40 CFR part 109 and describes the distribution of responsibilities and basic procedures for responding to an oil discharge and performing cleanup operations.

1.2 Resources at Risk

40 CFR 109.5(b)(1)

Clearwater's Big Bear Lease No. 2 Production Facility is located approximately 6 miles North of Madison, LA, within the Mines River watershed (see Figure C-1 in Appendix C). The waterways closest to the facility are Big Bear Creek, which flows approximately ½ mile to the east of the facility, and the Mines River, which flows 6 miles to the south in a west-to-east direction and receives water from Big Bear Creek. The facility diagram included in Appendix C (Figure C-2) indicates the location of the oil extraction, production, and storage areas. Ground cover at the facility consists of compacted soil, gravel, and low lying vegetation. The natural topography of the land is graded in an east-southeast direction, and all surface drainage from the facility therefore flows towards Big Bear Creek. The slope is relatively mild: approximately 4 feet vertical per mile (5,280 feet) horizontal.

Three flowlines (which contain oil) at the facility lack adequate secondary containment (see Figure C-2):

- **Flowline A.** The flowline from Well A to the tank battery (FLA) is approximately 2,100 feet long. It runs aboveground in a north-south direction to the tank battery area.

- **Flowline B.** The flowline between Well B and the tank battery (FLB) is approximately 3,400 feet long. It travels in a southwest direction to the tank battery area. This flowline runs the closest to navigable waters. At the closest point, the flowline is located ½ mile from Big Bear Creek.

- **Flowline SWD.** The flowline between the tank battery and the saltwater disposal well is approximately 2,000 feet long. It runs in an east-west direction.

All three flowlines are aboveground, with the exception of a short portion of Flowline B that is buried under the dirt/gravel access road. A drainage ditch runs along the access road to the east of the tank battery and along Route 417. The ditch flows into Big Bear Creek. Given the direction of surface drainage, a discharge from any of the three flowlines could reach Big Bear Creek, either directly or via the drainage ditch, and from there, flow southward to the Mines River.

Neither Big Bear Creek nor the Mines River is used as a public drinking water supply, although animals grazing on the nearby land are often seen drinking from Big Bear Creek and the Howard Fleming Farm has an agricultural irrigation intake on Big Bear Creek (see the Notification Form later in this Plan for contact information). The two waterways, however, provide habitat for a number of aquatic species and mammals and are used by local residents for recreational purposes. The Mines River runs through the center of Madison. Recreational and scenic areas are located on both banks of the river.

A public park is located approximately 1 mile east from the town center and 8 miles from the facility. Recreational uses on the Mines River include picnic areas, walking trails, canoeing, and nature watching.

There are no residences within the immediate vicinity of the facility. The closest residence is located 1 mile to the north of the site, upstream on Big Bear Creek. The closest residence downstream from the site is located 3 miles away. Both residences have private drinking water wells. Clearwater will coordinate with the Madison fire and/or police departments and with its residential neighbors to provide the appropriate warnings in the event of a discharge that could affect public health and safety.

1.3 Risk Assessment

The facility is comprised of approximately 7,500 feet of 2-inch diameter flowlines. With the exception of a short road crossing, the flowlines are located aboveground. The flowlines do not have secondary containment, since such containment is impracticable at this facility (see discussion on impracticability of secondary containment in the facility's SPCC Plan).

40 CFR 109.5(c)(2)

The total daily production rate at the facility varies, but can reach as much as 1,260 gallons of crude oil and 5,880 gallons of produced water. The two wells have approximately equal production rates (each 3,570 gallons per day). Flowline B, the longest of the three flowlines and the one closest to navigable waters, contains up to 555 gallons of oil/water when charged. The facility is visited daily. For planning purposes, the worst-case discharge is therefore the volume of oil within the flowline plus 24 hours of production, or 4,125 gallons.

A discharge of this quantity of oil could potentially reach Big Bear Creek. The velocity of oil over land is estimated, based on past experience and a simple calculation of flow over short grass pastureland, at approximately 0.2 feet/second.[1] Considering the distance between Flowline B and Big Bear Creek (½ mile) and the 2-foot elevation gradient, the oil, if unimpeded, could reach Big Bear Creek in as little as 4 hours. The water current in Big Bear Creek averages approximately 0.3 feet/second during high stages. Over a 24-hour period, the oil could travel approximately 5 miles downstream from the release point. The Mines River, which is located only 6 miles downstream to the south of the tank battery area, could therefore possibly be affected by a discharge.

[1] Calculated using sheet flow transport equations.

1.4 Response Strategy

Clearwater personnel and contractors are equipped and trained to respond to certain “minor discharges” confined within the facility. Minor discharges can generally be described as those where the quantity of product discharged is small, the discharged material can be easily stopped and controlled, the discharge is localized, and the product is not likely to seep into groundwater or reach surface water or adjoining shorelines. Procedures for responding to these minor discharges are covered in the SPCC Plan.

This Contingency Plan addresses all discharge incidents, including those that affect navigable waters or during which the oil cannot be safely controlled by facility personnel and confined within the boundaries of the facility. Response to such incidents may necessitate the assistance of outside contractors or other responders to prevent imminent impact to navigable waters.

PART II
Spill Discovery and Response

2.1 Distribution of Responsibilities

40 CFR 109.5(a)
40 CFR 109.5(d)(2)

Clearwater has the primary responsibility for providing the initial response to oil discharge incidents originating from its facility. To accomplish this, Clearwater has designated the Field Operations Manager, Bill Laurier, as the qualified oil discharge Response Coordinator (RC) in the event of an oil discharge.

The RC plays a central coordinating role in any emergency situation, as illustrated in the emergency organization chart in Figure 2-1.

40 CFR 109.5(b)(2)

The RC has the authority to commit the necessary services and equipment to respond to the discharge and to request assistance from Madison fire and/or police departments, contractors, or other responders, as appropriate.

The RC will direct notifications and initial response actions in accordance with training and capabilities. In the event of a fire or emergency situation that threatens the health and safety of those present at the site, the RC will direct evacuations and contact the fire and police departments.

In the event of an emergency involving outside response agencies, the RC's primary responsibility is to provide information regarding the characteristics of the materials and equipment involved and to provide access to Clearwater resources as requested. The RC shall also take necessary measures to control the flow of people, emergency equipment, and supplies and obtain the support of the Madison Police Department as needed to maintain control of the site. These controls may be necessary to minimize injuries and confusion.

Finally, the RC serves as the coordinator for radio communications by acquiring all essential information and ensuring clear communication of information to emergency response personnel. The RC has access to reference material at the field office either as printed material or on computer files that can further assist the response activities.

Whenever circumstances permit, the RC transmits assessments and recommendations to Clearwater Senior Management for direction. Senior Management is contacted in the following order: (1) Regional Director of Operations; (2) Vice-President of Operations.

In the event that the Field Operations Manager is not available, the responsibility and authority for initiating a response to a discharge rests with the most senior Clearwater employee on site at the time the discharge is discovered (Crew Lead) or with the

contractor Field Supervisor (or next person in command) if contractor personnel are the only personnel on site.

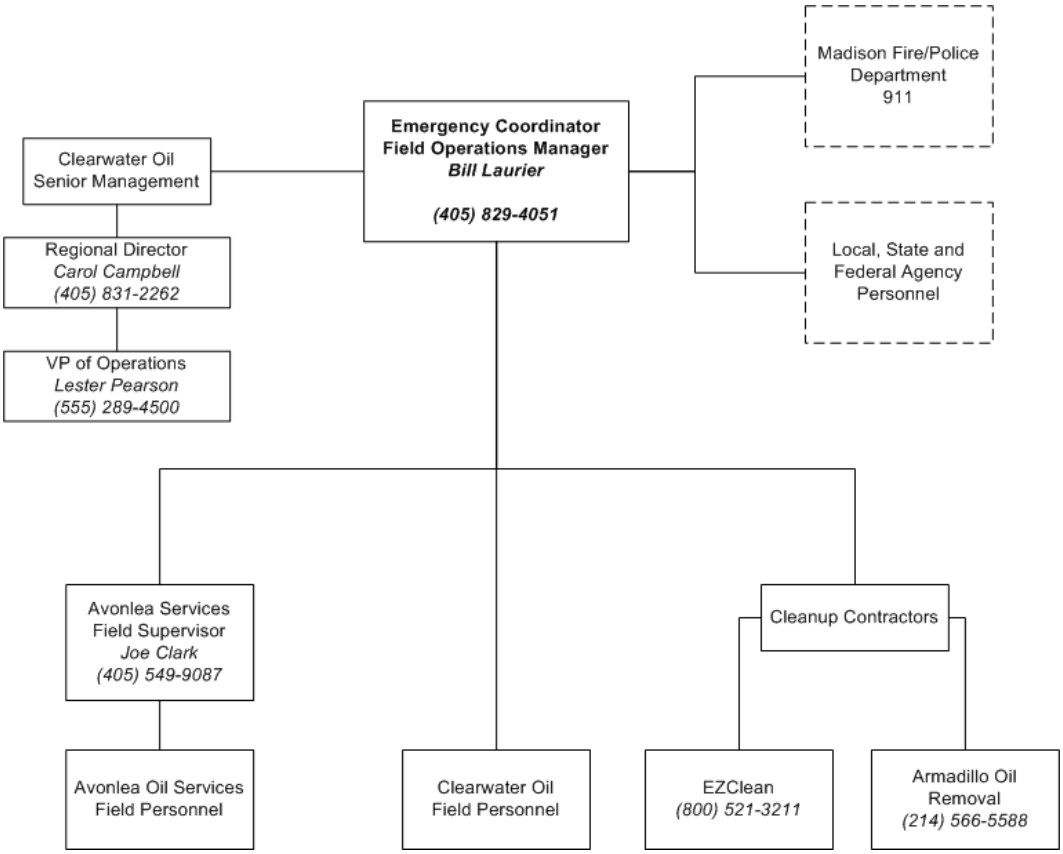


Figure 2-1. Distribution of response authority and communication.

2.2 Response Activities

40 CFR 109.5(d)
40 CFR 109.5(e)

In the event of a discharge, the first priority is to stop the product flow and to shut off all ignition sources, followed by the containment, control, and mitigation of the discharge. This Contingency Plan breaks actions to be performed to respond to an oil discharge into different phases, described in greater detail in the checklists below.

2.2.1 Discharge Discovery and Source Control

Minor Discharge. A minor discharge (i.e., small volume leak from flowlines or other equipment) will be discovered by Clearwater facility personnel or by contractor personnel during scheduled daily or monthly visits to the facility. Aboveground flowlines are visually inspected formally once a month during the normal inspection rounds.

Major Discharge. A more severe and sudden discharge will trigger the automatic shut down of the pumping units and will affect oil production. The impact will be detected during the daily visit to the production area by Clearwater or contractor field personnel. The maximum amount of time until a major discharge is detected can be up to 24 hours.

Notifications to the National Response Center, Louisiana authorities, and St. Anthony's Parish Emergency Committee must occur immediately upon discovery of reportable discharges.

Completed	Actions
	Immediately report the discharge to the RC, providing the following information: • Exact location; • Material involved; • Quantity involved; • Topographic and environmental conditions; • Circumstances that may hinder response; and • Injuries, if any.
	Turn off all sources of ignition.
	Turn off lift pumps that charge or provide flow to the flowline.
	Locate the flowline break.
	If safe to do so, isolate the affected section of piping by closing off the closest valves upstream and downstream from the break.

2.2.2 Assessment and Notifications

Completed	Actions
	Investigate the discharge to assess the actual or potential threat to human health or the environment: • Location of the discharge relative to receiving waterbodies; • Quantity of spilled material; • Ambient conditions (temperature, rain); • Other contributing factors such as fire or explosion hazards; and • Sensitive receptors downstream.
	Request outside assistance from local emergency responders, as needed.
	Evaluate the need to evacuate facility and evacuate employees, as needed.
	Notify the fire/police departments and St. Anthony's Parish Emergency Committee to assess whether community evacuation is needed.
	Notify immediately: • 911 • National Response Center • Response contractor(s) • St. Anthony's Parish Emergency Planning Committee • State authorities
	Communicate with neighboring property owners regarding the discharge and actions taken to mitigate the damage.
	If the oil reaches (or threatens to reach) the Mines River, notify the local fire/police departments to limit access to the River by local residents until the oil has been contained and recovered. Additionally, notify downstream water users of the spill and of actions that will be taken to protect these downstream receptors.

2.2.3 Control and Recovery

The RC directs the initial control of the oil flow by Clearwater, Avonlea Oil Services, and other contractor personnel. The actions taken will depend on whether the oil has reached water or is still on land. All effort will be made to prevent oil from reaching water.

If the oil has not yet reached water:

Completed	Actions
	Deploy sand bags and absorbent socks downgradient from the oil, or erect temporary barriers such as trenches or mounds to prevent the oil from flowing towards Big Bear Creek.
	Implement land based response actions (countermeasure) such as digging temporary containment pits, ponds, or curbs to prevent the flow of oil into the river.
	Deploy absorbent sock and sorbent material along the shoreline to prevent oil from entering waters.

If the oil has reached water:

Completed	Actions
	Contact cleanup contractor(s).
	Deploy floating booms immediately downstream from the release point. Big Bear Creek is narrow and shallow. Floating boom deployment does not require the use of a boat.
	Control oil flow on the ground by placing absorbent socks and other sorbent material or physical barriers (e.g., “kitty litter,” sandbags, earthen berm, trenches) across the oil flow path.
	Deploy additional floating booms across the whole width of the Creek at the next access point downstream from the release point. Access points and staging areas along the shoreline are identified on Figure C-1 of this Contingency Plan.
	Deploy protective booming measures for downstream receptors that may be impacted by the spill.

2.2.4 Disposal of Recovered Product and Contaminated Response Material

The RC ensures that all contaminated materials classified as hazardous waste are disposed of in accordance with all applicable solid and hazardous waste regulations.

Completed	Actions
	Place any recovered product that can be recycled into the gun barrel tank to be separated and recycled.
	Dispose of recovered product not suitable for on-site recycling with the rest of the waste collected during the response efforts.

	Collect all debris in properly labeled waste containers (impervious bags, drums, or buckets).
	Dispose of contaminated material in accordance with all applicable solid and hazardous waste regulations using a licensed waste hauler and disposal facility, after appropriately characterizing the material for collection and disposal.
	Dispose of all contaminated response material within 2 weeks of the discharge.

2.2.5 Termination

The RC ensures that cleanup has been completed and that the contaminated area has been treated or mitigated according to the applicable regulations and state/federal cleanup action levels. The RC collaborates with the local, state and federal authorities regarding the assessment of damages.

Completed	Actions
	Ensure that all repairs to the defective equipment or flowline section have been completed.
	Review circumstances that led to the discharge and take all necessary precautions to prevent a recurrence.
	Evaluate the effectiveness of the response activities and make adjustments as necessary to response procedures and personnel training.
	Carry out personnel and contractor debriefings as necessary to emphasize prevention measures or to communicate changes in operations or response procedures.
	Submit any required follow-up reports to the authorities. In the case where the discharge (as defined in 40 CFR 112.1(b)) was greater than 1,000 gallons or was the second discharge (as defined in 40 CFR 112.1(b)) of 42 gallons or more within any 12-month period, the RC is responsible for submitting the required information within 60 days to the EPA Regional Administrator following the procedures outlined in Appendix B. *40 CFR 112.4(a)* Within 30 days of the discharge, the RC will convene an incident critique including all appropriate persons that responded to the spill. The goal of the incident critique is to discuss lessons learned, the efficacy of the Contingency Plan and its implementation, and coordination of the plan/RC and other state and local plans. Within 60 days of the critique, the Contingency Plan will be updated (as needed) to incorporate the results, findings, and suggestions developed during the critique.

2.3 Discharge Notification

40 CFR109.5(b)(2)

Instructions and phone numbers for reporting a discharge to the National Response Center and other federal, state, and local authorities are provided in Appendix B to this Plan. *Any discharge to water must be reported immediately to the National Response Center.* The Response Coordinator must ensure that details of the discharge are recorded on the Discharge Notification Form provided in Appendix B.

If the discharge qualifies under 40 CFR part 112 (see Appendix B for conditions), the RC is responsible for ensuring that all pertinent information is provided to the EPA Regional Administrator.

PART III
Response Resources and Preparedness Activities

3.1 Equipment, Supplies, Services, and Manpower

40 CFR 109.5(c)(1) and (c)(2)

Spill kits are provided in a storage shed at the production site that is accessible by both Clearwater and Avonlea personnel (see Figure C-2 in Appendix C). Response equipment and material present at the site include:

(4)	Empty 55-gallons drums to hold contaminated material
(1)	50-ft absorbent socks
(2)	10-ft sections of hard skirted deployment boom
(2)	50-ft floating booms
(200 pounds)	"Oil-dry" Loose absorbent material
(4 boxes)	2 ft x 3 ft absorbent pads
(3 boxes)	Nitrile gloves
(3 boxes)	Neoprene gloves
(6 pairs)	Vinyl/PVC pull-on overboots
(3)	Non-sparking shovels
(3)	Brooms
(20)	Sand bags
(1)	Combustible Gas Indicator with H_2S detection capabilities

This material is sufficient to respond to most minor discharges occurring at the facility and to initially contain a major discharge while waiting for additional material or support from outside contractors. The inventory is verified on a monthly basis during the scheduled facility inspection by designated personnel and is replenished as needed.

40 CFR 109.5(d)(3)

Additional material and equipment is kept at Clearwater's field office, located 25 miles from the facility. This additional material includes empty storage drums, absorbent socks and booms, containment booms, sand bags, personal protective gear, etc. It also includes all necessary communication equipment to coordinate response activities (cell phones, two-way radios). The Field Office serves as the response operation center during a response.

40 CFR 109.5(d)(2)

Clearwater has three employees trained and available to respond to an oil discharge. Clearwater personnel may be assisted by three additional employees from the facility's main contractor, Avonlea Oil Services. All employees are familiar with the facility layout, location of spill response equipment and staging areas, and response strategies, and with the SPCC and Oil Spill Contingency Plans for this facility. All have received training in the deployment of response material and handling of hazardous waste (HAZWOPER) and have attended the required refresher courses.

40 CFR 109.5(c)(3)

To respond to larger discharges and ensure the removal and disposal of cleanup debris, Clearwater has established agreements with two specialized cleanup contractors: EZClean and Armadillo Oil Removal, with EZClean contacted first and acting as the primary response/cleanup contractor and Armadillo Oil Removal acting as the alternate or in a supporting role. Contact information is provided in Appendix A. These contractors have immediate access to an assortment of equipment and materials, including mechanical recovery equipment for use on water and on land, small boats, floating booms, and large waste containers. Each contractor has sufficient response equipment to contain and recover the maximum possible discharge of 4,125 gallons. EZClean and Armadillo Oil Removal are able to respond *within 4 hours* of receiving a verbal request from the RC. Clearwater discusses response capacity needs on an annual basis with each contractor to ensure that sufficient equipment and material are available to respond to a potential 4,125-gallon discharge. The inventories of EZClean and Armadillo Oil Removal equipment are maintained with the response agreements and updated annually.

3.2 Access to Receiving Waterbody

40 CFR 109.5(d)(5)

Big Bear Creek would be the first waterbody affected in the event of a discharge. From there, the oil would flow into the Mines River. The response strategy consists of: (1) deploying booms and other response equipment at various points downstream from the oil plume to prevent its migration; and (2) deploying booms as a protective measure for an irrigation water intake and other downstream sensitive receptors.

Figure 3-2: Boom deployed across Big Bear Creek.

Vehicular access to Big Bear Creek is essential to ensure that the response equipment can be effectively deployed to contain oil at various points along the waterway and prevent further migration of the oil towards the Mines River.

Three access points have been established along Big Bear Creek and are marked on the map in Figure C-1 (BB1, BB2, and BB3). These access points provide sufficient cleared land for a staging area from which Clearwater or contractor personnel can deploy response equipment, and recover and store spilled oil. Twice a year, as part of the monthly inspection of the facility, Clearwater facility personnel drive to each access point and make sure that it remains accessible (e.g., vegetation is not overgrown and the

Figure 3-3: Boom deployed at Route 54 bridge crossing.

dirt trail is not impassable for a field vehicle). The respective property owners have agreed to allow access to Clearwater's personnel and contractors for response and maintenance purposes. Although no further approval is needed prior to the deployment of response equipment, the RC will contact the property owners as necessary to inform them of activities being carried out.

If necessary, three access points are also available along the Mines River. One is located in the center of Madison, at the bridge crossing for Route 101, the second is located at the public park two miles downstream from the center, and the third one is located at the bridge crossing for Route 54, four miles downstream from the center. Coordination with the Madison police/fire departments is necessary to stage equipment at these three access points.

3.3 Communications and Control

40 CFR 109.5(b)(3)
40 CFR 109.5(d)(3)

A central coordination center will be set up at the field office in the event of a discharge. The field office is equipped with a variety of fixed and mobile communication equipment (telephone, fax, cell phones, two-way radios, computers) to ensure continuous communication with Clearwater management, responders, authorities, and other interested parties.

Communications equipment includes:

- **Portable hand-held radios.** Clearwater maintains a two-way base station and four portable radio units. These radio units are kept at the field office as part of the response equipment. Local emergency responders have been provided with the response frequencies that will be used during an incident.
- **Cell phones.** Each field vehicle and the RC are provided with a cell phone. The RC and/or his alternate (Site Supervisor when the Field Operations Manager is not "on call") can be reached by cell phone 7 days a week, 24 hours a day.
- **Additional equipment.** Additional equipment will be obtained from EZClean and/or Armadillo Oil Removal in the event that more communications equipment is necessary.

The RC is responsible for communicating the status of the response operations and for sharing relevant information with involved parties, including local, state, and federal authorities.

In the event that local response agencies, Louisiana authorities, or a federal On Site Coordinator (OSC) assumes Incident Command, the RC will function as the facility representative in the Unified Command structure.

3.4 Training Exercises and Updating Procedures

40 CFR 109.5(d)(1)

Clearwater has established and maintains an ongoing training program to ensure that Clearwater personnel responding to oil discharges are properly trained and that all necessary equipment is available to them. The program includes on-the-job training on the proper deployment of response equipment and periodic practice drills during which Clearwater personnel are asked to deploy equipment and material in response to a simulated discharge. The RC is responsible for implementing and evaluating employee preparedness training.

Following a response to an oil discharge, the RC will evaluate the actions taken and identify procedural areas where improvements are needed. The RC will conduct a briefing with field personnel, contractors, and local emergency responders to discuss lessons learned and will integrate the outcome of the discussion in subsequent SPCC briefings and employee training seminars. As necessary, the RC will amend this Contingency Plan or the SPCC Plan to reflect changes made to the facility equipment and procedures. A Professional Engineer will certify any technical amendment to the SPCC Plan.

40 CFR 109.5(b)(2)

APPENDIX A
EMERGENCY CONTACTS

Facility Operations

Name	Title	Telephone	Address
Bill Laurier	Field Operations Manager Clearwater Oil Co.	(405) 831-6322 (office) (405) 829-4051 (cell)	2451 Mountain Drive Ridgeview, LA 70180
Carol Campbell	Regional Director of Operations Clearwater Oil Co.	(405) 831-6320 (office) (405) 831-2262 (cell)	2451 Mountain Drive Ridgeview, LA 70180
Lester Pearson	Vice-President of Operations Clearwater Oil Co.	(555)-289-4500	13000 Main Street, Suite 400 Houston, TX 77077
Joe Clark	Field Supervisor Avonlea Services, Inc.	(406) 545-2285 (office) (406) 549-9087 (cell)	786 Cherry Creek Road Avonlea, LA 70180
William Mackenzie	Pumper Avonlea Services, Inc.	(406) 549-9087 (cell)	786 Cherry Creek Road Avonlea, LA 70180

Local Emergency Responders

Name	Telephone	Address
Fire/Police Departments	911 (405) 830-2000	2451 Mountain Drive, Madison, LA 70180
Emerson Hospital	(405) 831-9558	13000 Main Street, Madison, LA 70180

Cleanup Contractors

Name	Telephone	Address
EZClean	(800) 521-3211	1200 Industry Park Drive, Gardner, LA 70180
Armadillo Oil Removal	(214) 566-5588	25 B Street, Suite #6, Madison, LA 70180

Neighboring Property Owners

Name	Telephone	Address	Location
Maurice Richard	(405) 830-2186	5540 Route 417, Madison, LA 70180	BB1
Jim Larouche	(405) 832-2645	6075 Greenfield Drive, Madison, LA 70180	BB2
Peter Martin	(405) 832-5527	1644 Oilfield Road, Madison, LA 70180	BB3
Howard Fleming	(405) 235-6893	531 Horseshoe Road, Madison, LA 70180	

APPENDIX B
DISCHARGE NOTIFICATION PROCEDURES

Circumstances, instructions, and phone numbers for reporting a discharge to the National Response Center and other federal, state, and local agencies, and to other affected parties, are provided below. They are also posted at the facility in the storage shed containing the discharge response equipment. Note that any discharge to water must be reported immediately to the National Response Center.

Field Operations Manager, Bill Laurier (24 hours) (405) 829-4051

Local Emergency (fire, explosion, or other hazards) 911

Agency / Organization	Agency Contact	Circumstances	When to Notify
Federal Agencies			
National Response Center	1-800-424-8802	Discharge reaching navigable waters.	**Immediately (verbal)**
EPA Region VI (Hotline)	1-800-887-6063		**Immediately (verbal)**
EPA Region VI Regional Administrator	First Interstate Bank Tower at Fountain Place 1445 Ross Avenue, 12th floor, Suite 1200 Dallas TX 75202	Discharge 1,000 gallons or more; or second discharge of 42 gallons or more over a 12-month period.	Written notification within 60 days (see Section 2.1 of this Plan)
State Agencies			
Office of State Police, Transportation and Environmental Safety Section, Hazardous Materials Hotline	225-925-6595 or 1-877-925-6595	1) Injury requiring hospitalization or fatality. 2) Fire, explosion, or other impact that could affect public safety. 3) Release exceeding 24-hour reportable quantity. 4) Impact to areas beyond the facility's confines.	**Immediately (verbal)** Written notification to be made within 5 days.
Office of State Police, Transportation and Environmental Safety Section, Hazardous Materials Hotline	225-925-6595 or 1-877-925-6595	Discharges that pose emergency conditions, regardless of the volume discharged.	**Within 1 hour** of discovery (verbal). Written notification within 7 working days.

Agency / Organization	Agency Contact	Circumstances	When to Notify
Louisiana Department of Environmental Quality, Office of Environmental Compliance	225-763-3908 or 225-342-1234 (after business hours, weekends and holidays)	Discharges that do not pose emergency conditions	Within 24 hours of discovery (verbal). Written notification within 7 working days.
Local Agencies			
St. Anthony's Parish Emergency Planning Committee	337-828-1960	Any discharge of 100 lbs or more that occurs beyond the boundaries of the facility, including to the air.	**Immediately (verbal)** Written notification within 7 days.
Others			
Response/cleanup contractors	EZClean (800) 521-3211 Armadillo Oil Removal Co. (214) 566-5588	Any discharge that exceeds the capacity of facility personnel to respond and clean up.	As needed
Howard Fleming Farm (agricultural irrigation intake)	(405) 235-6893	Any discharge that threatens to affect neighboring properties and irrigation intakes.	As needed
Maurice Richard	405-830-2186	When deploying response equipment from Access Point BB1 on Big Bear Creek.	As needed
Jim Larouche	405-832-2645	When deploying response equipment from Access Point BB2 on Big Bear Creek.	As needed
Peter Martin	405-832-5527	When deploying response equipment from Access Point BB3 on Big Bear Creek.	As needed

The person reporting the discharge must provide the following information:

- Name, location, organization, and telephone number
- Name and address of the owner/operator
- Date and time of the incident
- Location of the incident
- Source and cause of discharge
- Types of material(s) discharged
- Total quantity of materials discharged
- Quantity discharged in harmful quantity (to navigable waters or adjoining shorelines)
- Danger or threat posed by the release or discharge
- Description of all affected media (e.g., water, soil)

- Number and types of injuries (if any) and damaged caused
- Weather conditions
- Actions used to stop, remove, and mitigate effects of the discharge
- Whether an evacuation is needed
- Name of individuals and/or organizations contacted
- Any other information that may help emergency personnel respond to the incident

Whenever the facility discharges more than 1,000 gallons of oil in a single event, or discharges more than 42 gallons of oil in each of two discharge incidents within a 12-month period, the Manager of Field Operations must provide the following information to the U.S. Environmental Protection Agency's Regional Administrator within 60 days:

- Name of the facility
- Name of the owner or operator
- Location of the facility
- Maximum storage or handling capacity and normal daily throughput
- Corrective actions and countermeasures taken, including a description of equipment repairs and replacements
- Description of facility, including maps, flow diagrams, and topographical maps
- Cause of the discharge(s) to navigable waters, including a failure analysis of the system and subsystems in which the failure occurred.
- Additional preventive measures taken or contemplated to minimize possibility of recurrence
- Other pertinent information requested by the Regional Administrator.

Discharge Notification Form

*** Notification must not be delayed if information or individuals are not available. Additional pages may be attached to supplement information contained in the form.

Facility: Clearwater Oil Company Big Bear Lease No. 2 Production Facility
5800 Route 417
Madison, Louisiana 73506

Description of Discharge		
Date/time	Release date: Release time: Duration:	Discovery date: Discovery time:
Reporting Individual	Name:	Tel. #:
Location of discharge	Latitude: Longitude:	Description:
Equipment source	☐ piping ☐ flowline ☐ well ☐ unknown ☐ stock, flare	Description: Equipment ID:
Product	☐ crude oil ☐ saltwater ☐ other*	* Describe other:
Appearance and description		
Environmental conditions	Wind direction: Wind speed:	Rainfall: Current:
Impacts		
Quantity	Released:	Recovered:
Receiving medium	☐ water** ☐ land ☐ other (describe):	☐ Release confined to company property. ☐ Release outside company property. ** If water, indicate extent and body of water:
Describe circumstances of the release		
Assessment of impacts and remedial actions		
Disposal method for recovered material		
Action taken to prevent incident from reoccurring		

Safety issues	☐ Injuries ☐ Fatalities ☐ Evacuation	
Notifications		
Agency	**Name**	**Date/time reported & Comments**
Company Spill Response Coordinator		
National Response Center 1-800-424-8802		
State police		
Parish Emergency Response Commission		
OSRO/cleanup contractor		

Appendix C
SITE PLAN AND FACILITY DIAGRAM

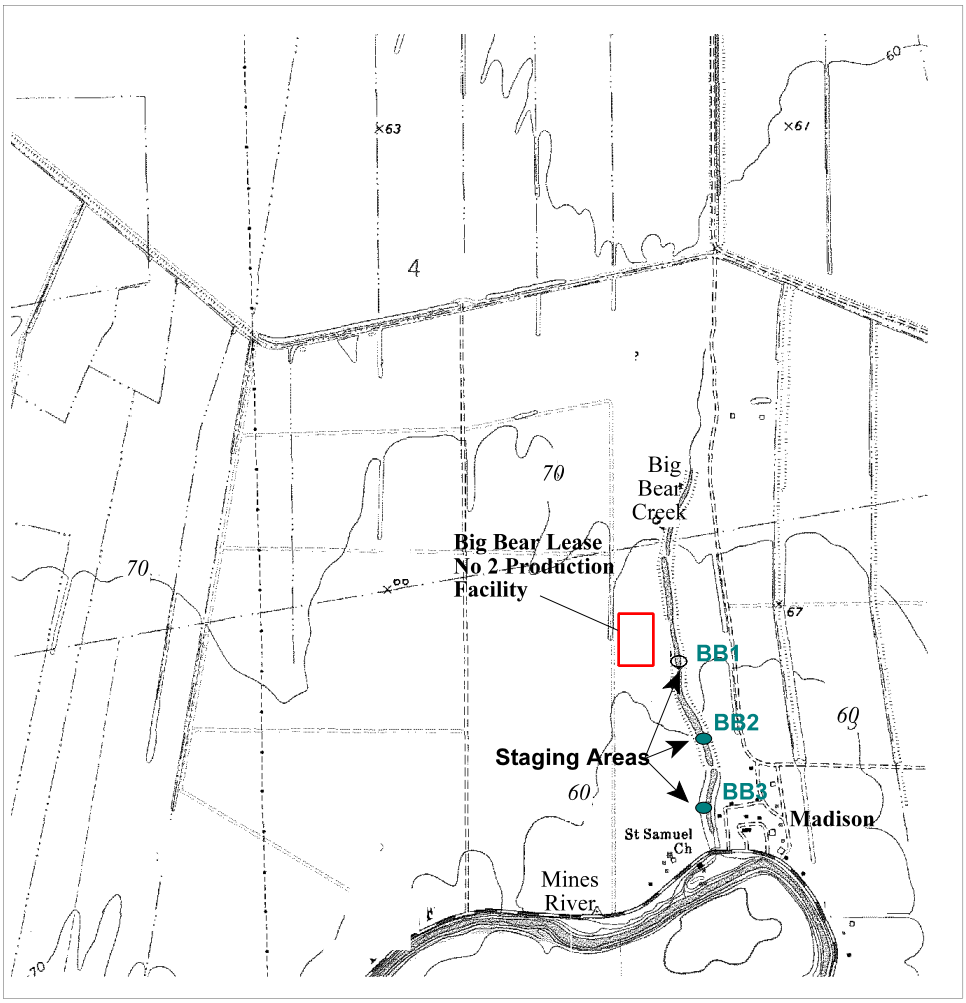


Figure C-1: Site Plan (pre-designated staging areas are indicated).

Staging area	Location	Contact Information
BB1	5540 Route 417, Madison, LA (access from path to the right of the storage shed).	Maurice Richard; 405-830-2186
BB2	6075 Greenfield Drive, Madison, LA.	Jim Larouche; 405-832-2645
BB3	1644 Oilfield Road, Madison, LA	Peter Martin; 405-832-5527

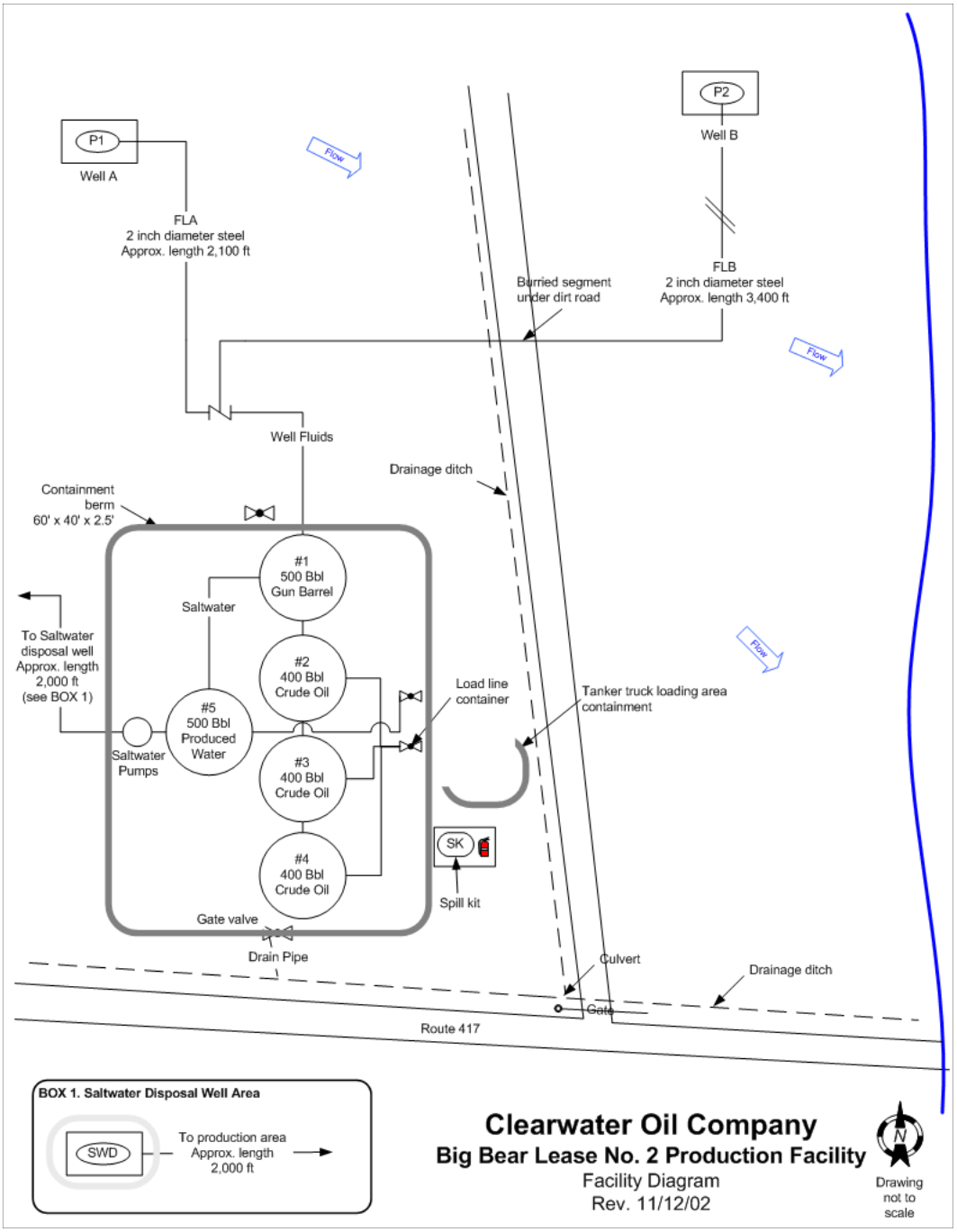


Figure C-2: Facility Diagram.

Appendix G: SPCC Inspection Checklists

- Onshore Facilities (excluding production)
- Onshore Oil Production, Drilling, and Workover Facilities
- Offshore Oil Production, Drilling, and Workover
- Tier I Qualified Facility Checklist

U.S. ENVIRONMENTAL PROTECTION AGENCY
SPCC FIELD INSPECTION AND PLAN REVIEW CHECKLIST

ONSHORE FACILITIES (EXCLUDING OIL DRILLING, PRODUCTION AND WORKOVER)

Overview of the Checklist

This checklist is designed to assist EPA inspectors in conducting a thorough and nationally consistent inspection of a facility's compliance with the Spill Prevention, Control, and Countermeasure (SPCC) rule at 40 CFR part 112. It is a required tool to help federal inspectors (or their contractors) record observations for the site inspection and review of the SPCC Plan. While the checklist is meant to be comprehensive, the inspector should always refer to the SPCC rule in its entirety, the SPCC Regional Inspector Guidance Document, and other relevant guidance for evaluating compliance. This checklist must be completed in order for an inspection to count toward an agency measure (i.e., OEM inspection measures or GPRA). The completed checklist and supporting documentation (i.e. photo logs or additional notes) serve as the inspection report.

This checklist addresses requirements for onshore facilities including Tier II Qualified Facilities (excluding facilities involved in oil drilling, production and workover activities) that meet the eligibility criteria set forth in §112.3(g)(2).

Separate standalone checklists address requirements for:
Onshore oil drilling, production, and workover facilities including Tier II Qualified Facilities as defined in §112.3(g)(2);
Offshore drilling, production and workover facilities; and
Tier I Qualified Facilities (for facilities that meet the eligibility criteria defined in §112.3(g)(1))

Qualified facilities must meet the rule requirements in §112.6 and other applicable sections specified in §112.6, except for deviations that provide environmental equivalence and secondary containment impracticability determinations as allowed under §112.6.

The checklist is organized according to the SPCC rule. Each item in the checklist identifies the relevant section and paragraph in 40 CFR part 112 where that requirement is stated.

- Sections 112.1 through 112.5 specify the applicability of the rule and requirements for the preparation, implementation, and amendment of SPCC Plans. For these sections, the checklist includes data fields to be completed, as well as several questions with "yes," "no" or "NA" answers.
- Section 112.6 includes requirements for qualified facilities. These provisions are addressed in Attachment D.
- Section 112.7 includes general requirements that apply to all facilities (unless otherwise excluded).
- Sections 112.8 and 112.12 specify requirements for spill prevention, control, and countermeasures for onshore facilities (excluding production facilities).

The inspector needs to evaluate whether the requirement is addressed adequately or inadequately in the SPCC Plan and whether it is implemented adequately in the field (either by field observation or record review). For the SPCC Plan and implementation in the field, if a requirement is addressed adequately, mark the "Yes" box in the appropriate column. If a requirement is not addressed adequately, mark the "No" box. If a requirement does not apply to the particular facility or the question asked is not appropriate for the facility, mark as "NA". Discrepancies or descriptions of inspector interpretation of "No" vs. "NA" may be documented in the comments box subsequent to each section. If a provision of the rule applies only to the SPCC Plan, the "Field" column is shaded.

Space is provided throughout the checklist to record comments. Additional space is available as Attachment E at the end of the checklist. Comments should remain factual and support the evaluation of compliance.

Attachments

- Attachment A is for recording information about containers and other locations at the facility that require secondary containment.
- Attachment B is a checklist for documentation of the tests and inspections the facility operator is required to keep with the SPCC Plan.
- Attachment C is a checklist for oil spill contingency plans following 40 CFR 109. Unless a facility has submitted a Facility Response Plan (FRP) under 40 CFR 112.20, a contingency plan following 40 CFR 109 is required if a facility determines that secondary containment is impracticable as provided in 40 CFR 112.7(d). The same requirement for an oil spill contingency plan applies to the owner or operator of a facility with qualified oil-filled operational equipment that chooses to implement alternative requirements instead of general secondary containment requirements as provided in 40 CFR 112.7(k).
- Attachment D is a checklist for Tier II Qualified Facilities.
- Attachment E is for recording additional comments or notes.
- Attachment F is for recording information about photos.

FACILITY INFORMATION			
FACILITY NAME:			
LATITUDE:	LONGITUDE:	GPS DATUM:	
Section/Township/Range:	FRS#/OIL DATABASE ID:	ICIS#:	
ADDRESS:			
CITY:	STATE:	ZIP:	COUNTY:
MAILING ADDRESS (IF DIFFERENT FROM FACILITY ADDRESS – IF NOT, PRINT "SAME"):			
CITY:	STATE:	ZIP:	COUNTY:
TELEPHONE:	FACILITY CONTACT NAME/TITLE:		
OWNER NAME:			
OWNER ADDRESS:			
CITY:	STATE:	ZIP:	COUNTY:
TELEPHONE:	FAX:	EMAIL:	
FACILITY OPERATOR NAME (IF DIFFERENT FROM OWNER – IF NOT, PRINT "SAME"):			
OPERATOR ADDRESS:			
CITY:	STATE:	ZIP:	COUNTY:
TELEPHONE:	OPERATOR CONTACT NAME/TITLE:		
FACILITY TYPE:			NAICS CODE:
HOURS PER DAY FACILITY ATTENDED:		TOTAL FACILITY CAPACITY:	
TYPE(S) OF OIL STORED:			
LOCATED IN INDIAN COUNTRY? ☐ YES ☐ NO RESERVATION NAME:			

INSPECTION/PLAN REVIEW INFORMATION		
PLAN REVIEW DATE:	REVIEWER NAME:	
INSPECTION DATE:	TIME:	ACTIVITY ID NO:
LEAD INSPECTOR:		
OTHER INSPECTOR(S):		

INSPECTION ACKNOWLEDGMENT	
I performed an SPCC inspection at the facility specified above.	
INSPECTOR SIGNATURE:	DATE:
SUPERVISOR REVIEW/SIGNATURE:	DATE:

SPCC GENERAL APPLICABILITY—40 CFR 112.1

IS THE FACILITY REGULATED UNDER 40 CFR part 112?

The completely buried oil storage capacity is over 42,000 U.S. gallons, **OR** the aggregate aboveground oil storage capacity is over 1,320 U.S. gallons **AND** ☐ Yes ☐ No

The facility is a non-transportation-related facility engaged in drilling, producing, gathering, storing, processing, refining, transferring, distributing, using, or consuming oil and oil products, which due to its location could reasonably be expected to discharge oil into or upon the navigable waters of the United States ☐ Yes ☐ No

AFFECTED WATERWAY(S):	DISTANCE:

FLOW PATH TO WATERWAY:

Note: The following storage capacity is not considered in determining applicability of SPCC requirements:

- *Equipment subject to the authority of the U.S. Department of Transportation, U.S. Department of the Interior, or Minerals Management Service, as defined in Memoranda of Understanding dated November 24, 1971, and November 8, 1993; Tank trucks that return to an otherwise regulated facility that contain only residual amounts of oil (EPA Policy letter)*
- *Completely buried tanks subject to all the technical requirements of 40 CFR part 280 or a state program approved under 40 CFR part 281;*
- *Underground oil storage tanks deferred under 40 CFR part 280 that supply emergency diesel generators at a nuclear power generation facility licensed by the Nuclear Regulatory Commission (NRC) and subject to any NRC provision regarding design and quality criteria, including but not limited to CFR part 50;*
- *Any facility or part thereof used exclusively for wastewater treatment (production, recovery or recycling of oil is not considered wastewater treatment); (This does not include other oil containers located at a wastewater treatment facility, such as generator tanks or transformers)*
- *Containers smaller than 55 U.S. gallons;*
- *Permanently closed containers (as defined in §112.2);*
- *Motive power containers(as defined in §112.2);*
- *Hot-mix asphalt or any hot-mix asphalt containers;*
- *Heating oil containers used solely at a single-family residence;*
- *Pesticide application equipment and related mix containers;*
- *Any milk and milk product container and associated piping and appurtenances; and*
- *Intra-facility gathering lines subject to the regulatory requirements of 49 CFR part 192 or 195.*

Does the facility have an SPCC Plan? ☐ Yes ☐ No

FACILITY RESPONSE PLAN (FRP) APPLICABILITY—40 CFR 112.20(f)

A non-transportation related onshore facility is required to prepare and implement an FRP as outlined in 40 CFR 112.20 if:

- ☐ The facility transfers oil over water to or from vessels and has a total oil storage capacity greater than or equal to 42,000 U.S. gallons, **OR**
- ☐ The facility has a total oil storage capacity of at least 1 million U.S. gallons, **AND** at least one of the following is true:
  - ☐ The facility does not have secondary containment sufficiently large to contain the capacity of the largest aboveground tank plus sufficient freeboard for precipitation.
  - ☐ The facility is located at a distance such that a discharge could cause injury to fish and wildlife and sensitive environments.
  - ☐ The facility is located such that a discharge would shut down a public drinking water intake.
  - ☐ The facility has had a reportable discharge greater than or equal to 10,000 U.S. gallons in the past 5 years.

Facility has FRP: ☐ Yes ☐ No ☐ NA	FRP Number:

Facility has a completed and signed copy of Appendix C, Attachment C-II, "Certification of the Applicability of the Substantial Harm Criteria." ☐ Yes ☐ No

Comments:

SPCC TIER II QUALIFIED FACILITY APPLICABILITY—40 CFR 112.3(g)(2)	
The aggregate aboveground oil storage capacity is 10,000 U.S. gallons or less **AND**	☐ Yes ☐ No
In the three years prior to the SPCC Plan self-certification date, or since becoming subject to the rule (if the facility has been in operation for less than three years), the facility has **NOT** had:	
• A single discharge as described in §112.1(b) exceeding 1,000 U.S. gallons, **OR**	☐ Yes ☐ No
• Two discharges as described in §112.1(b) each exceeding 42 U.S. gallons within any twelve-month period[1]	☐ Yes ☐ No
IF ***YES*** TO ALL OF THE ABOVE, THEN THE FACILITY IS A TIER II QUALIFIED FACILITY[2] SEE ATTACHMENT D FOR TIER II QUALIFIED FACILITY CHECKLIST	

REQUIREMENTS FOR PREPARATION AND IMPLEMENTATION OF A SPCC PLAN—40 CFR 112.3		
Date facility began operations:		
Date of initial SPCC Plan preparation:	Current Plan version (date/number):	
112.3(a)	**For facilities (except farms), including mobile or portable facilities:**	
	• In operation on or prior to November 10, 2011: Plan prepared and/or amended and fully implemented by **November 10, 2011**	☐ Yes ☐ No ☐ NA
	• Beginning operations after November 10, 2011, Plan prepared and fully implemented before beginning operations	☐ Yes ☐ No ☐ NA
	For farms (as defined in §112.2):	
	• In operation on or prior to August 16, 2002: Plan maintained, amended and implemented by **May 10, 2013**	☐ Yes ☐ No ☐ NA
	• Beginning operations after August 16, 2002 through May 10, 2013: Plan prepared and fully implemented by **May 10, 2013**	☐ Yes ☐ No ☐ NA
	• Beginning operations after May 10, 2013: Plan prepared and fully implemented before beginning operations	☐ Yes ☐ No ☐ NA
112.3(d)	Plan is certified by a registered Professional Engineer (PE) and includes statements that the PE attests:	☐ Yes ☐ No ☐ NA
	• PE is familiar with the requirements of 40 CFR part 112	☐ Yes ☐ No ☐ NA
	• PE or agent has visited and examined the facility	☐ Yes ☐ No ☐ NA
	• Plan is prepared in accordance with good engineering practice including consideration of applicable industry standards and the requirements of 40 CFR part 112	☐ Yes ☐ No ☐ NA
	• Procedures for required inspections and testing have been established	☐ Yes ☐ No ☐ NA
	• Plan is adequate for the facility	☐ Yes ☐ No ☐ NA
PE Name:	License No.: / State: / Date of certification:	
112.3(e)(1)	Plan is available onsite if attended at least 4 hours per day. If facility is unattended, Plan is available at the nearest field office. *(Please note nearest field office contact information in comments section below.)*	☐ Yes ☐ No ☐ NA
Comments:		

[1] Oil discharges that result from natural disasters, acts of war, or terrorism are not included in this determination. The gallon amount(s) specified (either 1,000 or 42) refers to the amount of oil that actually reaches navigable waters or adjoining shorelines not the total amount of oil spilled. The entire volume of the discharge is oil for this determination.

[2] An owner/operator who self-certifies a Tier II SPCC Plan may include environmentally equivalent alternatives and/or secondary containment impracticability determinations when reviewed and certified by a PE.

AMENDMENT OF SPCC PLAN BY REGIONAL ADMINISTRATOR (RA)—40 CFR 112.4		
112.4(a),(c)	Has the facility discharged more than 1,000 U.S. gallons of oil in a single reportable discharge or more than 42 U.S. gallons in each of two reportable discharges in any 12-month period?[3]	☐ Yes ☐ No
If **YES**	• Was information submitted to the RA as required in §112.4(a)?[4]	☐ Yes ☐ No ☐ NA
	• Was information submitted to the appropriate agency or agencies in charge of oil pollution control activities in the State in which the facility is located§112.4(c)	☐ Yes ☐ No ☐ NA
	• Date(s) and volume(s) of reportable discharges(s) under this section:	
	• Were the discharges reported to the NRC[5]?	☐ Yes ☐ No
112.4(d),(e)	Have changes required by the RA been implemented in the Plan and/or facility?	☐ Yes ☐ No ☐ NA
Comments:		

AMENDMENT OF SPCC PLAN BY THE OWNER OR OPERATOR—40 CFR 112.5		
112.5(a)	Has there been a change at the facility that materially affects the potential for a discharge described in §112.1(b)?	☐ Yes ☐ No
If **YES**	• Was the Plan amended within six months of the change?	☐ Yes ☐ No
	• Were amendments implemented within six months of any Plan amendment?	☐ Yes ☐ No
112.5(b)	Review and evaluation of the Plan completed at least once every 5 years?	☐ Yes ☐ No ☐ NA
	Following Plan review, was Plan amended within six months to include more effective prevention and control technology that has been field-proven to significantly reduce the likelihood of a discharge described in §112.1(b)?	☐ Yes ☐ No ☐ NA
	Amendments implemented within six months of any Plan amendment?	☐ Yes ☐ No ☐ NA
	Five year Plan review and evaluation documented?	☐ Yes ☐ No ☐ NA
112.5(c)	Professional Engineer certification of any technical Plan amendments in accordance with all applicable requirements of §112.3(d) *[Except for self-certified Plans]*	☐ Yes ☐ No ☐ NA

Name:	License No.:	State:	Date of certification:
Reason for amendment:			
Comments:			

[3] A reportable discharge is a discharge as described in §112.1(b)(see 40 CFR part 110). The gallon amount(s) specified (either 1,000 or 42) refers to the amount of oil that actually reaches navigable waters or adjoining shorelines not the total amount of oil spilled. The entire volume of the discharge is oil for this determination.

[4] Triggering this threshold may disqualify the facility from meeting the Qualified Facility criteria if it occurred in the three years prior to self certification

[5] Inspector Note-Confirm any spills identified above were reported to NRC

GENERAL SPCC REQUIREMENTS—40 CFR 112.7		PLAN	FIELD
Management approval at a level of authority to commit the necessary resources to fully implement the Plan[6]		☐ Yes ☐ No	
Plan follows sequence of the rule or is an equivalent Plan meeting all applicable rule requirements and includes a cross-reference of provisions		☐ Yes ☐ No ☐ NA	
If Plan calls for facilities, procedures, methods, or equipment not yet fully operational, details of their installation and start-up are discussed *(Note: Relevant for inspection evaluation and testing baselines.)*		☐ Yes ☐ No ☐ NA	
112.7(a)(2)	The Plan includes deviations from the requirements of §§112.7(g), (h)(2) and (3), and (i) and applicable subparts B and C of the rule, except the secondary containment requirements in §§112.7(c) and (h)(1), 112.8(c)(2),112.8(c)(11), 112.12(c)(2), and 112.12(c)(11)	☐ Yes ☐ No ☐ NA	
If **YES**	• The Plan states reasons for nonconformance	☐ Yes ☐ No ☐ NA	
	• Alternative measures described in detail and provide equivalent environmental protection *(Note: Inspector should document if the environmental equivalence is implemented in the field, in accordance with the Plan's description)*	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA

Describe each deviation and reasons for nonconformance:

[6] May be part of the Plan or demonstrated elsewhere.

		PLAN	FIELD
112.7(a)(3)	Plan describes physical layout of facility and includes a diagram[7] that identifies: • Location and contents of all regulated fixed oil storage containers • Storage areas where mobile or portable containers are located • Completely buried tanks otherwise exempt from the SPCC requirements (marked as "exempt") • Transfer stations • Connecting pipes, including intra-facility gathering lines that are otherwise exempt from the requirements of this part under §112.1(d)(11)	☐ Yes ☐ No	☐ Yes ☐ No
	Plan addresses each of the following:		
(i)	For each fixed container, type of oil and storage capacity (see Attachment A of this checklist). For mobile or portable containers, type of oil and storage capacity for each container or an estimate of the potential number of mobile or portable containers, the types of oil, and anticipated storage capacities	☐ Yes ☐ No	☐ Yes ☐ No
(ii)	Discharge prevention measures, including procedures for routine handling of products (loading, unloading, and facility transfers, etc.)	☐ Yes ☐ No	☐ Yes ☐ No
(iii)	Discharge or drainage controls, such as secondary containment around containers, and other structures, equipment, and procedures for the control of a discharge	☐ Yes ☐ No	☐ Yes ☐ No
(iv)	Countermeasures for discharge discovery, response, and cleanup (both facility's and contractor's resources)	☐ Yes ☐ No	☐ Yes ☐ No
(v)	Methods of disposal of recovered materials in accordance with applicable legal requirements	☐ Yes ☐ No	
(vi)	Contact list and phone numbers for the facility response coordinator, National Response Center, cleanup contractors with an agreement for response, and all Federal, State, and local agencies who must be contacted in the case of a discharge as described in §112.1(b)	☐ Yes ☐ No	
112.7(a)(4)	***Does not apply if the facility has submitted an FRP under §112.20:*** ☐ Yes ☐ No ☐ NA Plan includes information and procedures that enable a person reporting an oil discharge as described in §112.1(b) to relate information on the: • Exact address or location and phone number of the facility; • Date and time of the discharge; • Type of material discharged; • Estimates of the total quantity discharged; • Estimates of the quantity discharged as described in §112.1(b); • Source of the discharge; • Description of all affected media; • Cause of the discharge; • Damages or injuries caused by the discharge; • Actions being used to stop, remove, and mitigate the effects of the discharge; • Whether an evacuation may be needed; and • Names of individuals and/or organizations who have also been contacted.		
112.7(a)(5)	***Does not apply if the facility has submitted a FRP under §112.20:*** Plan organized so that portions describing procedures to be used when a discharge occurs will be readily usable in an emergency	☐ Yes ☐ No ☐ NA	
112.7(b)	Plan includes a prediction of the direction, rate of flow, and total quantity of oil that could be discharged for each type of major equipment failure where experience indicates a reasonable potential for equipment failure	☐ Yes ☐ No ☐ NA	
Comments:			

[7] Note in comments any discrepancies between the facility diagram, the description of the physical layout of facility, and what is observed in the field

		PLAN	FIELD
112.7(c)	Appropriate containment and/or diversionary structures or equipment are provided to prevent a discharge as described in §112.1(b), **except as provided in §112.7(k) of this section for certain qualified operational equipment**. The entire containment system, including walls and floors, are capable of containing oil and are constructed to prevent escape of a discharge from the containment system before cleanup occurs. The method, design, and capacity for secondary containment address the typical failure mode and the most likely quantity of oil that would be discharged. See Attachment A of this checklist. **For onshore facilities**, one of the following or its equivalent: • Dikes, berms, or retaining walls sufficiently impervious to contain oil; • Curbing or drip pans; • Sumps and collection systems; • Culverting, gutters or other drainage systems; • Weirs, booms or other barriers; • Spill diversion pond; • Retention ponds; or • Sorbent materials.		
	Identify which of the following are present at the facility and if appropriate containment and/or diversionary structures or equipment are provided as described above:		
	☐ Bulk storage containers	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
	☐ Mobile/portable containers	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
	☐ Oil-filled operational equipment (as defined in 112.2)	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
	☐ Other oil-filled equipment (i.e., manufacturing equipment)	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
	☐ Piping and related appurtenances	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
	☐ Mobile refuelers or non-transportation-related tank cars	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
	☐ Transfer areas, equipment and activities	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
	☐ Identify any other equipment or activities that are not listed above: _____	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
112.7(d)	Secondary containment for one (or more) of the following provisions is determined to be impracticable: ☐ General secondary containment §112.7(c) ☐ Bulk storage containers §§112.8(c)(2)/112.12(c)(2) ☐ Loading/unloading rack §112.7(h)(1) ☐ Mobile/portable containers§§112.8(c)(11)/ 112.12(c)(11)	☐ Yes ☐ No	
If **YES**	• The impracticability of secondary containment is clearly demonstrated and described in the Plan	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
	• For bulk storage containers,[8] periodic integrity testing of containers and integrity and leak testing of the associated valves and piping is conducted	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
	(Does not apply if the facility has submitted a FRP under §112.20): • Contingency Plan following the provisions of 40 CFR part 109 is provided (see Attachment C of this checklist) **AND**	☐ Yes ☐ No ☐ NA	
	• Written commitment of manpower, equipment, and materials required to expeditiously control and remove any quantity of oil discharged that may be harmful	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA

Comments:

[8] These additional requirements apply only to bulk storage containers, when an impracticability determination has been made by the PE

		PLAN	FIELD
112.7(e)	Inspections and tests conducted in accordance with written procedures	☐ Yes ☐ No	☐ Yes ☐ No
	Record of inspections or tests signed by supervisor or inspector	☐ Yes ☐ No	☐ Yes ☐ No
	Kept with Plan for at least 3 years (see Attachment B of this checklist)[9]	☐ Yes ☐ No	☐ Yes ☐ No
112.7(f)	Personnel, training, and oil discharge prevention procedures		
(1)	Training of oil-handling personnel in operation and maintenance of equipment to prevent discharges; discharge procedure protocols; applicable pollution control laws, rules, and regulations; general facility operations; and contents of SPCC Plan	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
(2)	Person designated as accountable for discharge prevention at the facility and reports to facility management	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
(3)	Discharge prevention briefings conducted at least once a year for oil handling personnel to assure adequate understanding of the Plan. Briefings highlight and describe known discharges as described in §112.1(b) or failures, malfunctioning components, and any recently developed precautionary measures	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
112.7(g)	Plan describes how to: • Secure and control access to the oil handling, processing and storage areas; • Secure master flow and drain valves; • Prevent unauthorized access to starter controls on oil pumps; • Secure out-of-service and loading/unloading connections of oil pipelines; and • Address the appropriateness of security lighting to both prevent acts of vandalism and assist in the discovery of oil discharges.	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
112.7(h)	Tank car and tank truck loading/unloading rack[10] is present at the facility *Loading/unloading rack* means a fixed structure (such as a platform, gangway) necessary for loading or unloading a tank truck or tank car, which is located at a facility subject to the requirements of this part. A loading/unloading rack includes a loading or unloading arm, and may include any combination of the following: piping assemblages, valves, pumps, shut-off devices, overfill sensors, or personnel safety devices.	☐ Yes ☐ No	
If **YES** (1)	Does loading/unloading rack drainage flow to catchment basin or treatment facility designed to handle discharges or use a quick drainage system?	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
	Containment system holds at least the maximum capacity of the largest single compartment of a tank car/truck loaded/unloaded at the facility	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
(2)	An interlocked warning light or physical barriers, warning signs, wheel chocks, or vehicle brake interlock system in the area adjacent to the **loading or unloading rack** to prevent vehicles from departing before complete disconnection of flexible or fixed oil transfer lines	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
(3)	Lower-most drains and all outlets on tank cars/trucks inspected prior to filling/departure, and, if necessary ensure that they are tightened, adjusted, or replaced to prevent liquid discharge while in transit	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA

Comments:

[9] Records of inspections and tests kept under usual and customary business practices will suffice
[10] Note that a tank car/truck loading/unloading rack must be present for §112.7(h) to apply

		PLAN	FIELD
112.7(i)	Brittle fracture evaluation of field-constructed aboveground containers is conducted after tank repair, alteration, reconstruction, or change in service that might affect the risk of a discharge or after a discharge/failure due to brittle fracture or other catastrophe, and appropriate action taken as necessary (applies to only field-constructed aboveground containers)	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
112.7(j)	Discussion of conformance with applicable more stringent State rules, regulations, and guidelines and other effective discharge prevention and containment procedures listed in 40 CFR part 112	☐ Yes ☐ No ☐ NA	
112.7(k)	Qualified oil-filled operational equipment is present at the facility[11] ☐ Yes ☐ No *Oil-filled operational equipment* means equipment that includes an oil storage container (or multiple containers) in which the oil is present solely to support the function of the apparatus or the device. Oil-filled operational equipment is not considered a bulk storage container, and does not include oil-filled manufacturing equipment (flow-through process). Examples of oil-filled operational equipment include, but are not limited to, hydraulic systems, lubricating systems (e.g. , those for pumps, compressors and other rotating equipment, including pumpjack lubrication systems), gear boxes, machining coolant systems, heat transfer systems, transformers, circuit breakers, electrical switches, and other systems containing oil solely to enable the operation of the device. If **YES** Check which apply: Secondary Containment provided in accordance with 112.7(c) ☐ Alternative measure described below (confirm eligibility) ☐		
112.7(k)	Qualified Oil-Filled Operational Equipment • Has a single reportable discharge as described in §112.1(b) from any oil-filled operational equipment exceeding 1,000 U.S. gallons occurred within the three years prior to Plan certification date? ☐ Yes ☐ No ☐ NA • Have two reportable discharges as described in §112.1(b) from any oil-filled operational equipment each exceeding 42 U.S. gallons occurred within any 12-month period within the three years prior to Plan certification date?[12] ☐ Yes ☐ No ☐ NA		
	*If **YES** for either, secondary containment in accordance with §112.7(c) is required*		
	• Facility procedure for inspections or monitoring program to detect equipment failure and/or a discharge is established and documented	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
	Does not apply if the facility has submitted a FRP under §112.20: • Contingency plan following 40 CFR part 109 (see Attachment C of this checklist) is provided in Plan **AND**	☐ Yes ☐ No ☐ NA	
	• Written commitment of manpower, equipment, and materials required to expeditiously control and remove any quantity of oil discharged that may be harmful is provided in Plan	☐ Yes ☐ No ☐ NA	

Comments:

[11] This provision does not apply to oil-filled manufacturing equipment (flow-through process)

[12] Oil discharges that result from natural disasters, acts of war, or terrorism are not included in this determination. The gallon amount(s) specified (either 1,000 or 42) refers to the amount of oil that actually reaches navigable waters or adjoining shorelines not the total amount of oil spilled. The entire volume of the discharge is oil for this determination.

ONSHORE FACILITIES (EXCLUDING PRODUCTION) **40 CFR 112.8/112.12**		**PLAN**	**FIELD**
112.8(b)/ 112.12(b) Facility Drainage			
Diked Areas (1)	Drainage from diked storage areas is: • Restrained by valves, except where facility systems are designed to control such discharge, **OR** • Manually activated pumps or ejectors are used and the condition of the accumulation is inspected prior to draining dike to ensure no oil will be discharged	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
(2)	Diked storage area drain valves are manual, open-and-closed design (not flapper-type drain valves)	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
	If drainage is released directly to a watercourse and not into an onsite wastewater treatment plant, retained storm water is inspected and discharged per §§112.8(c)(3)(ii), (iii), and (iv) or §§112.12(c)(3)(ii), (iii), and (iv).	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
Undiked Areas (3)	Drainage from undiked areas with a potential for discharge designed to flow into ponds, lagoons, or catchment basins to retain oil or return it to facility. Catchment basin located away from flood areas.[13]	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
(4)	If facility drainage not engineered as in (b)(3) (i.e., drainage flows into ponds, lagoons, or catchment basins) then the facility is equipped with a diversion system to retain oil in the facility in the event of an uncontrolled discharge.[14]	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
(5)	Are facility drainage waters continuously treated in more than one treatment unit and pump transfer is needed?	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
If ***YES***	• Two "lift" pumps available and at least one permanently installed	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
	• Facility drainage systems engineered to prevent a discharge as described in §112.1(b) in the case of equipment failure or human error	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
Comments:			
112.8(c)/112.12(c) Bulk Storage Containers ☐ NA *Bulk storage container* means any container used to store oil. These containers are used for purposes including, but not limited to, the storage of oil prior to use, while being used, or prior to further distribution in commerce. Oil-filled electrical, operating, or manufacturing equipment is not a bulk storage container. *If bulk storage containers are not present, mark this section Not Applicable (NA). If present, complete this section and Attachment A of this checklist.*			
(1)	Containers materials and construction are compatible with material stored and conditions of storage such as pressure and temperature	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
(2)	Except for mobile refuelers and other non-transportation-related tank trucks, construct all bulk storage tank installations with secondary containment to hold capacity of largest container and sufficient freeboard for precipitation	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
	Diked areas sufficiently impervious to contain discharged oil **OR**	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
	Alternatively, any discharge to a drainage trench system will be safely confined in a facility catchment basin or holding pond	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA

[13] Oil discharges that result from natural disasters, acts of war, or terrorism are not included in this determination. The gallon amount(s) specified (either 1,000 or 42) refers to the amount of oil that actually reaches navigable waters or adjoining shorelines not the total amount of oil spilled. The entire volume of the discharge is oil for this determination.

[14] These provisions apply only when a facility drainage system is used for containment; otherwise mark NA

		PLAN	FIELD
(3)	Is there drainage of uncontaminated rainwater from diked areas into a storm drain or open watercourse?	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
If **YES**	• Bypass valve normally sealed closed	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
	• Retained rainwater is inspected to ensure that its presence will not cause a discharge as described in §112.1(b)	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
	• Bypass valve opened and resealed under responsible supervision	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
	• Adequate records of drainage are kept; for example, records required under permits issued in accordance with 40 CFR §§122.41(j)(2) and (m)(3)	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
(4)	For completely buried metallic tanks installed on or after January 10, 1974 (if not exempt from SPCC regulation because subject to all of the technical requirements of 40 CFR part 280 or 281):		
	• Provide corrosion protection with coatings or cathodic protection compatible with local soil conditions	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
	• Regular leak testing conducted	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
(5)	The buried section of partially buried or bunkered metallic tanks protected from corrosion with coatings or cathodic protection compatible with local soil conditions	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
(6)	• Test or inspect each aboveground container for integrity on a regular schedule and whenever you make material repairs. Techniques include, but are not limited to: visual inspection, hydrostatic testing, radiographic testing, ultrasonic testing, acoustic emissions testing, or other system of non-destructive testing	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
	• Appropriate qualifications for personnel performing tests and inspections are identified in the Plan and have been assessed in accordance with industry standards	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
	• The frequency and type of testing and inspections are documented, are in accordance with industry standards and take into account the container size, configuration and design	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
	• Comparison records of aboveground container integrity testing are maintained	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
	• Container supports and foundations regularly inspected	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
	• Outside of containers frequently inspected for signs of deterioration, discharges, or accumulation of oil inside diked areas	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
	• Records of all inspections and tests maintained[15]	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
Integrity Testing Standard identified in the Plan:			
112.12 (c)(6)(ii) *(Applies to AFVO Facilities only)*	Conduct formal visual inspection on a regular schedule for bulk storage containers that meet all of the following conditions: • Subject to 21 CFR part 110; • Elevated; • Constructed of austenitic stainless steel; • Have no external insulation; and • Shop-fabricated.	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
	In addition, you must frequently inspect the outside of the container for signs of deterioration, discharges, or accumulation of oil inside diked areas.	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
	You must determine and document in the Plan the appropriate qualifications for personnel performing tests and inspections.[16]	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA

[15] Records of inspections and tests kept under usual and customary business practices will suffice

		PLAN	FIELD
(7)	Leakage through defective internal heating coils controlled: • Steam returns and exhaust lines from internal heating coils that discharge into an open watercourse are monitored for contamination, **OR** • Steam returns and exhaust lines pass through a settling tank, skimmer, or other separation or retention system	☐ Yes ☐ No ☐ NA ☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA ☐ Yes ☐ No ☐ NA
(8)	Each container is equipped with at least one of the following for liquid level sensing: • High liquid level alarms with an audible or visual signal at a constantly attended operation or surveillance station, or audible air vent in smaller facilities; • High liquid level pump cutoff devices set to stop flow at a predetermined container content level; • Direct audible or code signal communication between container gauger and pumping station; • Fast response system for determining liquid level (such as digital computers, telepulse, or direct vision gauges) and a person present to monitor gauges and overall filling of bulk containers; or • Regularly test liquid level sensing devices to ensure proper operation.	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
(9)	Effluent treatment facilities observed frequently enough to detect possible system upsets that could cause a discharge as described in §112.1(b)	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
(10)	Visible discharges which result in a loss of oil from the container, including but not limited to seams, gaskets, piping, pumps, valves, rivets, and bolts are promptly corrected and oil in diked areas is promptly removed	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
(11)	Mobile or portable containers positioned to prevent a discharge as described in §112.1(b). Mobile or portable containers (excluding mobile refuelers and other non-transportation-related tank trucks) have secondary containment with sufficient capacity to contain the largest single compartment or container and sufficient freeboard to contain precipitation	☐ Yes ☐ No ☐ NA ☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA ☐ Yes ☐ No ☐ NA
112.8(d)/112.12(d)Facility transfer operations, pumping, and facility process			
(1)	Buried piping installed or replaced on or after August 16, 2002 has protective wrapping or coating Buried piping installed or replaced on or after August 16, 2002 is also cathodically protected or otherwise satisfies corrosion protection standards for piping in 40 CFR part 280 or 281 Buried piping exposed for any reason is inspected for deterioration; corrosion damage is examined; and corrective action is taken	☐ Yes ☐ No ☐ NA ☐ Yes ☐ No ☐ NA ☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA ☐ Yes ☐ No ☐ NA ☐ Yes ☐ No ☐ NA
(2)	Piping terminal connection at the transfer point is marked as to origin and capped or blank-flanged when not in service or in standby service for an extended time	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
(3)	Pipe supports are properly designed to minimize abrasion and corrosion and allow for expansion and contraction	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
(4)	Aboveground valves, piping, and appurtenances such as flange joints, expansion joints, valve glands and bodies, catch pans, pipeline supports, locking of valves, and metal surfaces are inspected regularly to assess their general condition Integrity and leak testing conducted on buried piping at time of installation, modification, construction, relocation, or replacement	☐ Yes ☐ No ☐ NA ☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA ☐ Yes ☐ No ☐ NA
(5)	Vehicles warned so that no vehicle endangers aboveground piping and other oil transfer operations	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA

Comments:

This page left intentionally blank.

ATTACHMENT A: SPCC FIELD INSPECTION AND PLAN REVIEW TABLE

Documentation of Field Observations for Containers and Associated Requirements

Inspectors should use this table to document observations of containers as needed.

Containers and Piping

Check containers for leaks, specifically looking for: drip marks, discoloration of tanks, puddles containing spilled or leaked material, corrosion, cracks, and localized dead vegetation, and standards/specifications of construction.

Check aboveground container foundation for: cracks, discoloration, and puddles containing spilled or leaked material, settling, gaps between container and foundation, and damage caused by vegetation roots.

Check all piping for: droplets of stored material, discoloration, corrosion, bowing of pipe between supports, evidence of stored material seepage from valves or seals, evidence of leaks, and localized dead vegetation. For all aboveground piping, include the general condition of flange joints, valve glands and bodies, drip pans, pipe supports, bleeder and gauge valves, and other such items (Document in comments section of §112.8(d) or 112.12(d).)

Secondary Containment (Active and Passive)

Check secondary containment for: containment system (including walls and floor) ability to contain oil such that oil will not escape the containment system before cleanup occurs, proper sizing, cracks, discoloration, presence of spilled or leaked material (standing liquid), erosion, corrosion, penetrations in the containment system, and valve conditions.

Check dike or berm systems for: level of precipitation in dike/available capacity, operational status of drainage valves (closed), dike or berm impermeability, debris, erosion, impermeability of the earthen floor/walls of diked area, and location/status of pipes, inlets, drainage around and beneath containers, presence of oil discharges within diked areas.

Check drainage systems for: an accumulation of oil that may have resulted from any small discharge, including field drainage systems (such as drainage ditches or road ditches), and oil traps, sumps, or skimmers. Ensure any accumulations of oil have been promptly removed.

Check retention and drainage ponds for: erosion, available capacity, presence of spilled or leaked material, debris, and stressed vegetation.

Check active measures (countermeasures) for: amount indicated in plan is available and appropriate; deployment procedures are realistic; material is located so that they are readily available; efficacy of discharge detection; availability of personnel and training, appropriateness of measures to prevent a discharge as described in §112.1(b).

Container ID/ General Condition[16] Aboveground or Buried Tank	Storage Capacity and Type of Oil	Type of Containment/ Drainage Control	Overfill Protection and Testing & Inspections

[16] Identify each tank with either an A to indicate aboveground or B for completely buried

ATTACHMENT A: SPCC FIELD INSPECTION AND PLAN REVIEW TABLE (CONT.)

Documentation of Field Observations for Containers and Associated Requirements

Container ID/ General Condition[17] Aboveground or Buried Tank	Storage Capacity and Type of Oil	Type of Containment/ Drainage Control	Overfill Protection and Testing & Inspections

[17] Identify each tank with either an A to indicate aboveground or B for completely buried

ATTACHMENT B: SPCC INSPECTION AND TESTING CHECKLIST

Required Documentation of Tests and Inspections

Records of inspections and tests required by 40 CFR part 112 signed by the appropriate supervisor or inspector must be kept by all facilities with the SPCC Plan for a period of three years. Records of inspections and tests conducted under usual and customary business practices will suffice. Documentation of the following inspections and tests should be kept with the SPCC Plan.

Inspection or Test		Documentation		Not Applicable
		Present	Not Present	
112.7–General SPCC Requirements				
(d)	Integrity testing for bulk storage containers with no secondary containment system and for which an impracticability determination has been made	☐	☐	☐
(d)	Integrity and leak testing of valves and piping associated with bulk storage containers with no secondary containment system and for which an impracticability determination has been made	☐	☐	☐
(h)(3)	Inspection of lowermost drain and all outlets of tank car or tank truck prior to filling and departure from loading/unloading rack	☐	☐	☐
(i)	Evaluation of field-constructed aboveground containers for potential for brittle fracture or other catastrophic failure when the container undergoes a repair, alteration, reconstruction or change in service or has discharged oil or failed due to brittle fracture failure or other catastrophe	☐	☐	☐
k(2)(i)	Inspection or monitoring of qualified oil-filled operational equipment when the equipment meets the qualification criteria in §112.7(k)(1) and facility owner/operator chooses to implement the alternative requirements in §112.7(k)(2) that include an inspection or monitoring program to detect oil-filled operational equipment failure and discharges	☐	☐	☐
112.8/112.12–Onshore Facilities (excluding oil production facilities)				
(b)(1), (b)(2)	Inspection of storm water released from diked areas into facility drainage directly to a watercourse	☐	☐	☐
(c)(3)	Inspection of rainwater released directly from diked containment areas to a storm drain or open watercourse before release, open and release bypass valve under supervision, and records of drainage events	☐	☐	☐
(c)(4)	Regular leak testing of completely buried metallic storage tanks installed on or after January 10, 1974 and regulated under 40 CFR 112	☐	☐	☐
(c)(6)	Regular integrity testing of aboveground containers and integrity testing after material repairs, including comparison records	☐	☐	☐
(c)(6), (c)(10)	Regular visual inspections of the outsides of aboveground containers, supports and foundations	☐	☐	☐
(c)(6)	Frequent inspections of diked areas for accumulations of oil	☐	☐	☐
(c)(8)(v)	Regular testing of liquid level sensing devices to ensure proper operation	☐	☐	☐
(c)(9)	Frequent observations of effluent treatment facilities to detect possible system upsets that could cause a discharge as described in §112.1(b)	☐	☐	☐
(d)(1)	Inspection of buried piping for damage when piping is exposed and additional examination of corrosion damage and corrective action, if present	☐	☐	☐
(d)(4)	Regular inspections of aboveground valves, piping and appurtenances and assessments of the general condition of flange joints, expansion joints, valve glands and bodies, catch pans, pipeline supports, locking of valves, and metal surfaces	☐	☐	☐
(d)(4)	Integrity and leak testing of buried piping at time of installation, modification, construction, relocation or replacement	☐	☐	☐

This page left intentionally blank.

ATTACHMENT C: SPCC CONTINGENCY PLAN REVIEW CHECKLIST

☐ NA

40 CFR Part 109–Criteria for State, Local and Regional Oil Removal Contingency Plans

If SPCC Plan includes an impracticability determination for secondary containment in accordance with §112.7(d), the facility owner/operator is required to provide an oil spill contingency plan following 40 CFR part 109, unless he or she has submitted a FRP under §112.20. An oil spill contingency plan may also be developed, unless the facility owner/operator has submitted a FRP under §112.20 as one of the required alternatives to general secondary containment for qualified oil filled operational equipment in accordance with §112.7(k).

	109.5–Development and implementation criteria for State, local and regional oil removal contingency plans[18]	**Yes**	**No**
(a)	Definition of the authorities, responsibilities and duties of all persons, organizations or agencies which are to be involved in planning or directing oil removal operations.	☐	☐
(b)	Establishment of notification procedures for the purpose of early detection and timely notification of an oil discharge including:	☐	☐
(1)	The identification of critical water use areas to facilitate the reporting of and response to oil discharges.	☐	☐
(2)	A current list of names, telephone numbers and addresses of the responsible persons (with alternates) and organizations to be notified when an oil discharge is discovered.	☐	☐
(3)	Provisions for access to a reliable communications system for timely notification of an oil discharge, and the capability of interconnection with the communications systems established under related oil removal contingency plans, particularly State and National plans (e.g., National Contingency Plan (NCP)).	☐	☐
(4)	An established, prearranged procedure for requesting assistance during a major disaster or when the situation exceeds the response capability of the State, local or regional authority.	☐	☐
(c)	Provisions to assure that full resource capability is known and can be committed during an oil discharge situation including:	☐	☐
(1)	The identification and inventory of applicable equipment, materials and supplies which are available locally and regionally.	☐	☐
(2)	An estimate of the equipment, materials and supplies that would be required to remove the maximum oil discharge to be anticipated.	☐	☐
(3)	Development of agreements and arrangements in advance of an oil discharge for the acquisition of equipment, materials and supplies to be used in responding to such a discharge.	☐	☐
(d)	Provisions for well-defined and specific actions to be taken after discovery and notification of an oil discharge including:	☐	☐
(1)	Specification of an oil discharge response operating team consisting of trained, prepared and available operating personnel.	☐	☐
(2)	Pre-designation of a properly qualified oil discharge response coordinator who is charged with the responsibility and delegated commensurate authority for directing and coordinating response operations and who knows how to request assistance from Federal authorities operating under existing national and regional contingency plans.	☐	☐
(3)	A preplanned location for an oil discharge response operations center and a reliable communications system for directing the coordinated overall response operations.	☐	☐
(4)	Provisions for varying degrees of response effort depending on the severity of the oil discharge.	☐	☐
(5)	Specification of the order of priority in which the various water uses are to be protected where more than one water use may be adversely affected as a result of an oil discharge and where response operations may not be adequate to protect all uses.	☐	☐
(e)	Specific and well defined procedures to facilitate recovery of damages and enforcement measures as provided for by State and local statutes and ordinances.	☐	☐

[18] The contingency plan should be consistent with all applicable state and local plans, Area Contingency Plans, and the NCP.

This page left intentionally blank.

ATTACHMENT D: TIER II QUALIFIED FACILITY CHECKLIST ☐ NA

TIER II QUALIFIED FACILITY PLAN REQUIREMENTS —40 CFR 112.6(b)		
112.6(b)(1)	**Plan Certification:** Owner/operator certified in the Plan that:	☐ Yes ☐ No
(i)	He or she is familiar with the requirements of 40 CFR part 112	☐ Yes ☐ No ☐ NA
(ii)	He or she has visited and examined the facility[19]	☐ Yes ☐ No ☐ NA
(iii)	The Plan has been prepared in accordance with accepted and sound industry practices and standards and with the requirements of this part	☐ Yes ☐ No ☐ NA
(iv)	Procedures for required inspections and testing have been established	☐ Yes ☐ No ☐ NA
(v)	He or she will fully implement the Plan	☐ Yes ☐ No ☐ NA
(vi)	The facility meets the qualification criteria set forth under §112.3(g)(2)	☐ Yes ☐ No ☐ NA
(vii)	The Plan does not deviate from any requirements as allowed by §§112.7(a)(2) and 112.7(d), except as described under §112.6(b)(3)(i) or (ii)	☐ Yes ☐ No ☐ NA
(viii)	The Plan and individual(s) responsible for implementing the Plan have the full approval of management and the facility owner or operator has committed the necessary resources to fully implement the Plan.	☐ Yes ☐ No ☐ NA
112.6(b)(2)	**Technical Amendments:** The owner/operator self-certified the Plan's technical amendments for a change in facility design, construction, operation, or maintenance that affected potential for a §112.1(b) discharge	☐ Yes ☐ No ☐ NA
If **YES**	• Certification of technical amendments is in accordance with the self-certification provisions of §112.6(b)(1).	☐ Yes ☐ No ☐ NA
(i)	A PE certified a portion of the Plan (i.e., Plan is informally referred to as a hybrid Plan)	☐ Yes ☐ No ☐ NA
If **YES**	• The PE also certified technical amendments that affect the PE certified portion of the Plan as required under §112.6(b)(4)(ii)	☐ Yes ☐ No ☐ NA
(ii)	The aggregate aboveground oil storage capacity increased to more than 10,000 U.S. gallons as a result of the change	☐ Yes ☐ No ☐ NA
If **YES**	*The facility no longer meets the Tier II qualifying criteria in §112.3(g)(2) because it exceeds 10,000 U.S. gallons in aggregate aboveground storage capacity.*	
	The owner/operator prepared and implemented a Plan within 6 months following the change and had it certified by a PE under §112.3(d)	☐ Yes ☐ No ☐ NA
112.6(b)(3)	**Plan Deviations:** Does the Plan include environmentally equivalent alternative methods or impracticability determinations for secondary containment?	☐ Yes ☐ No ☐ NA
If **YES**	Identify the alternatives in the hybrid Plan:	
	• Environmental equivalent alternative method(s) allowed under §112.7(a)(2);	☐ Yes ☐ No ☐ NA
	• Impracticability determination under §112.7(d)	☐ Yes ☐ No ☐ NA
112.6(b)(4)	• For each environmentally equivalent measure, the Plan is accompanied by a written statement by the PE that describes: the reason for nonconformance, the alternative measure, and how it offers equivalent environmental protection in accordance with §112.7(a)(2);	☐ Yes ☐ No ☐ NA
	• For each secondary containment impracticability determination, the Plan explains the reason for the impracticability determination and provides the alternative measures to secondary containment required in §112.7(d)	☐ Yes ☐ No ☐ NA
	AND	
(i)	PE certifies in the Plan that:	
(A)	He/she is familiar with the requirements of 40 CFR Part 112	☐ Yes ☐ No ☐ NA
(B)	He/she or a representative agent has visited and examined the facility	☐ Yes ☐ No ☐ NA
(C)	The alternative method of environmental equivalence in accordance with §112.7(a)(2) or the determination of impracticability and alternative measures in accordance with §112.7(d) is consistent with good engineering practice, including consideration of applicable industry standards, and with the requirements of 40 CFR Part 112.	☐ Yes ☐ No ☐ NA
Comments:		

[19] Note that only the person certifying the Plan can make the site visit

This page left intentionally blank.

ATTACHMENT E: ADDITIONAL COMMENTS

ATTACHMENT E: ADDITIONAL COMMENTS (CONT.)

ATTACHMENT F: PHOTO DOCUMENTATION NOTES

Photo#	Photographer Name	Time of Photo Taken	Compass Direction	Description

ATTACHMENT F: PHOTO DOCUMENTATION NOTES (CONT.)

Photo#	Photographer Name	Time of Photo Taken	Compass Direction	Description

U.S. ENVIRONMENTAL PROTECTION AGENCY
SPCC FIELD INSPECTION AND PLAN REVIEW CHECKLIST

ONSHORE OIL DRILLING, PRODUCTION AND WORKOVER FACILITIES

Overview of the Checklist

This checklist is designed to assist EPA inspectors in conducting a thorough and nationally consistent inspection of a facility's compliance with the Spill Prevention, Control, and Countermeasure (SPCC) rule at 40 CFR part 112. It is a required tool to help federal inspectors (or their contractors) record observations for the site inspection and review of the SPCC Plan. While the checklist is meant to be comprehensive, the inspector should always refer to the SPCC rule in its entirety, the SPCC Regional Inspector Guidance Document, and other relevant guidance for evaluating compliance. This checklist must be completed in order for an inspection to count toward an agency measure (i.e., OEM inspection measures or GPRA). The completed checklist and supporting documentation (i.e. photo logs or additional notes) serve as the inspection report.

This checklist addresses requirements for onshore oil drilling, production and workover facilities (including Tier II Qualified Facilities that meet the eligibility criteria set forth in §112.3(g)(2)). Qualified facilities must meet the rule requirements in §112.6 and other applicable sections specified in §112.6, except for deviations that provide environmental equivalence and secondary containment impracticability determinations as allowed under §112.6.

Separate and standalone checklists address the requirements for:
All other onshore facilities including Tier II Qualified Facilities (i.e., those facilities not involved in oil drilling, production and workover activities);
Offshore oil drilling, production and workover facilities; and
Tier I Qualified Facilities (for facilities that meet the eligibility criteria defined in §112.3(g)(1)).

The checklist is organized according to the SPCC rule. Each item in the checklist identifies the relevant section and paragraph in 40 CFR part 112 where that requirement is stated.

- Sections 112.1 through 112.5 specify the applicability of the rule and requirements for the preparation, implementation, and amendment of SPCC Plans. For these sections, the checklist includes data fields to be completed, as well as several questions with "yes," "no" "NA" answers.
- Section 112.6 includes requirements for qualified facilities. These provisions are addressed in Attachment D.
- Section 112.7 includes general requirements that apply to all facilities (unless otherwise excluded).
- Section 112.9 specifies spill prevention, control, and countermeasures requirements for onshore oil drilling, production and workover facilities
- Section 112.10 specifies spill prevention, control, and countermeasures requirements for onshore oil drilling, production and workover facilities.

The inspector needs to evaluate whether the requirement is addressed adequately or inadequately in the SPCC Plan and whether it is implemented adequately in the field (either by field observation or record review). For the SPCC Plan and implementation in the field, if a requirement is addressed adequately, mark the "Yes" box in the appropriate column. If a requirement is not addressed adequately, mark the "No" box. If a requirement does not apply to the particular facility or the question asked is not appropriate for the facility, mark as "NA". Discrepancies or descriptions of inspector interpretation of "No" vs. "NA" may be documented in the comments box subsequent to each section. If a provision of the rule applies only to the SPCC Plan, the "Field" column is shaded.

Space is provided throughout the checklist to record comments. Additional space is available as Attachment E at the end of the checklist. Comments should remain factual and support the evaluation of compliance.

Attachments

- Attachment A is for recording information about containers and other locations at the facility that require secondary containment.
- Attachment B is a checklist for documentation of the tests and inspections the facility operator is required to keep with the SPCC Plan.
- Attachment C is a checklist for oil spill contingency plans following 40 CFR 109. Unless a facility has submitted a Facility Response Plan (FRP) under 40 CFR 112.20, a contingency plan following 40 CFR 109 is required if a facility determines that secondary containment is impracticable as provided in 40 CFR 112.7(d). The same requirement for an oil spill contingency plan applies to the owner or operator of a facility with qualified oil-filled operational equipment that chooses to implement alternative requirements instead of general secondary containment requirements as provided in 40 CFR 112.7(k).
- Attachment D is a checklist for Tier II Qualified Facilities.
- Attachment E is for recording additional comments or notes.
- Attachment F is for recording information about photos.

FACILITY INFORMATION			
FACILITY NAME:			
LATITUDE:	LONGITUDE:	GPS DATUM:	
Section/Township/Range:	FRS#/OIL DATABASE ID:	ICIS#:	
ADDRESS:			
CITY:	STATE:	ZIP:	COUNTY:
MAILING ADDRESS (IF DIFFERENT FROM FACILITY ADDRESS – IF NOT, PRINT "SAME"):			
CITY:	STATE:	ZIP:	COUNTY:
TELEPHONE:	FACILITY CONTACT NAME/TITLE:		
OWNER NAME:			
OWNER ADDRESS:			
CITY:	STATE:	ZIP:	COUNTY:
TELEPHONE:	FAX:	EMAIL:	
FACILITY OPERATOR NAME (IF DIFFERENT FROM OWNER – IF NOT, PRINT "SAME"):			
OPERATOR ADDRESS:			
CITY:	STATE:	ZIP:	COUNTY:
TELEPHONE:	OPERATOR CONTACT NAME/TITLE:		
FACILITY TYPE:			NAICS CODE:
HOURS PER DAY FACILITY ATTENDED:		TOTAL FACILITY CAPACITY:	
TYPE(S) OF OIL STORED:			
LOCATED IN INDIAN COUNTRY? ☐ YES ☐ NO RESERVATION NAME:			

INSPECTION/PLAN REVIEW INFORMATION		
PLAN REVIEW DATE:	REVIEWER NAME:	
INSPECTION DATE:	TIME:	ACTIVITY ID NO:
LEAD INSPECTOR:		
OTHER INSPECTOR(S):		

INSPECTOR ACKNOWLEDGMENT	
I performed an SPCC inspection at the facility specified above.	
INSPECTOR SIGNATURE:	DATE:
SUPERVISOR REVIEW/SIGNATURE:	DATE:

SPCC GENERAL APPLICABILITY—40 CFR 112.1

IS THE FACILITY REGULATED UNDER 40 CFR part 112?

The completely buried oil storage capacity is over 42,000 U.S. gallons, **OR** the aggregate aboveground oil storage capacity is over 1,320 U.S. gallons **AND** ☐ Yes ☐ No

The facility is a non-transportation-related facility engaged in drilling, producing, gathering, storing, processing, refining, transferring, distributing, using, or consuming oil and oil products, which due to its location could reasonably be expected to discharge oil into or upon the navigable waters of the United States ☐ Yes ☐ No

AFFECTED WATERWAY(S):	DISTANCE:

FLOW PATH TO WATERWAY:

Note: The following storage capacity is not considered in determining applicability of SPCC requirements:

- *Equipment subject to the authority of the U.S. Department of Transportation, U.S. Department of the Interior, or Minerals Management Service, as defined in Memoranda of Understanding dated November 24, 1971, and November 8, 1993; Tank trucks that return to an otherwise regulated facility that contain only residual amounts of oil (EPA Policy letter)*
- *Completely buried tanks subject to all the technical requirements of 40 CFR part 280 or a state program approved under 40 CFR part 281;*
- *Underground oil storage tanks deferred under 40 CFR part 280 that supply emergency diesel generators at a nuclear power generation facility licensed by the Nuclear Regulatory Commission (NRC) and subject to any NRC provision regarding design and quality criteria, including but not limited to CFR part 50;*
- *Any facility or part thereof used exclusively for wastewater treatment (production, recovery or recycling of oil is not considered wastewater treatment); (This does not include other oil containers located at a wastewater treatment facility, such as generator tanks or transformers)*
- *Containers smaller than 55 U.S. gallons;*
- *Permanently closed containers (as defined in §112.2);*
- *Motive power containers (as defined in §112.2);*
- *Hot-mix asphalt or any hot-mix asphalt containers;*
- *Heating oil containers used solely at a single-family residence;*
- *Pesticide application equipment and related mix containers;*
- *Any milk and milk product container and associated piping and appurtenances; and*
- *Intra-facility gathering lines subject to the regulatory requirements of 49 CFR part 192 or 195.*

Does the facility have an SPCC Plan? ☐ Yes ☐ No

FACILITY RESPONSE PLAN (FRP) APPLICABILITY—40 CFR 112.20(f)

A non-transportation related onshore facility is required to prepare and implement an FRP as outlined in 40 CFR 112.20 if:

- ☐ The facility transfers oil over water to or from vessels and has a total oil storage capacity greater than or equal to 42,000 U.S. gallons, **OR**
- ☐ The facility has a total oil storage capacity of at least 1 million U.S. gallons, **AND** at least one of the following is true:
  - ☐ The facility does not have secondary containment sufficiently large to contain the capacity of the largest aboveground tank plus sufficient freeboard for precipitation.
  - ☐ The facility is located at a distance such that a discharge could cause injury to fish and wildlife and sensitive environments.
  - ☐ The facility is located such that a discharge would shut down a public drinking water intake.
  - ☐ The facility has had a reportable discharge greater than or equal to 10,000 U.S. gallons in the past 5 years.

Facility has FRP: ☐ Yes ☐ No ☐ NA	FRP Number:

Facility has a completed and signed copy of Appendix C, Attachment C-II, "Certification of the Applicability of the Substantial Harm Criteria." ☐ Yes ☐ No

Comments:

SPCC TIER II QUALIFIED FACILITY APPLICABILITY—40 CFR 112.3(g)(2)	
The aggregate aboveground oil storage capacity is 10,000 U.S. gallons or less **AND**	☐ Yes ☐ No
In the three years prior to the SPCC Plan self-certification date, or since becoming subject to the rule (if the facility has been in operation for less than three years), the facility has **NOT** had:	
• A single discharge as described in §112.1(b) exceeding 1,000 U.S. gallons, **OR**	☐ Yes ☐ No
• Two discharges as described in §112.1(b) each exceeding 42 U.S. gallons within any twelve-month period[1]	☐ Yes ☐ No
IF ***YES*** TO ALL OF THE ABOVE, THEN THE FACILITY IS A TIER II QUALIFIED FACILITY[2] SEE ATTACHMENT D FOR TIER II QUALIFIED FACILITY CHECKLIST	

REQUIREMENTS FOR PREPARATION AND IMPLEMENTATION OF A SPCC PLAN—40 CFR 112.3		
Date facility began operations:		
Date of initial SPCC Plan preparation:	Current Plan version (date/number):	
112.3(a)	For drilling, production or workover facilities, including mobile or portable facilities, that are offshore or have an offshore component; or facilities required to have and submit a FRP: • In operation on or prior to November 10, 2010: Plan prepared and/or amended and fully implemented by **November 10, 2010** • Facilities beginning operation after November 10, 2010: o Plan prepared and fully implemented before drilling and workover facilities begin operations; or o Plan prepared and fully implemented within six months after oil production facilities begin operations	☐ Yes ☐ No ☐ NA ☐ Yes ☐ No ☐ NA ☐ Yes ☐ No ☐ NA
	For all other drilling, production or workover facilities, including mobile or portable facilities: • In operation on or prior to November 10, 2011: Plan prepared and/or amended and fully implemented by **November 10, 2011** • Facilities beginning operation after November 10, 2011: o Plan prepared and fully implemented before drilling and workover facilities begin operations; or o Plan prepared and fully implemented within six months after oil production facilities begin operations	☐ Yes ☐ No ☐ NA ☐ Yes ☐ No ☐ NA ☐ Yes ☐ No ☐ NA
112.3(d)	Plan is certified by a registered Professional Engineer (PE) and includes statements that the PE attests: • PE is familiar with the requirements of 40 CFR part 112 • PE or agent has visited and examined the facility • Plan is prepared in accordance with good engineering practice including consideration of applicable industry standards and the requirements of 40 CFR part 112 • Procedures for required inspections and testing have been established • Plan is adequate for the facility • For produced water containers subject to 112.9(c)(6), any procedure to minimize the amount of free-phase oil is designed to reduce the accumulation of free-phase oil and the procedures and frequency for required inspections, maintenance and testing have been established and are described in the Plan, if applicable	☐ Yes ☐ No ☐ NA ☐ Yes ☐ No ☐ NA ☐ Yes ☐ No ☐ NA ☐ Yes ☐ No ☐ NA ☐ Yes ☐ No ☐ NA ☐ Yes ☐ No ☐ NA ☐ Yes ☐ No ☐ NA

PE Name:	License No.:	State:	Date of certification:

112.3(e)(1)	Plan is available onsite if attended at least 4 hours per day. If facility is unattended, Plan is available at the nearest field office. *(Please note nearest field office contact information in comments section below.)*	☐ Yes ☐ No ☐ NA
Comments:		

[1] Oil discharges that result from natural disasters, acts of war, or terrorism are not included in this determination. The gallon amount(s) specified (either 1,000 or 42) refers to the amount of oil that actually reaches navigable waters or adjoining shorelines not the total amount of oil spilled. The entire volume of the discharge is oil for this determination.

[2] An owner/operator who self-certifies a Tier II SPCC Plan may not include any environmentally equivalent alternatives or secondary containment impracticability determinations unless reviewed and certified by a PE.

AMENDMENT OF SPCC PLAN BY REGIONAL ADMINISTRATOR (RA)—40 CFR 112.4		
112.4(a),(c)	Has the facility discharged more than 1,000 U.S. gallons of oil in a single reportable discharge or more than 42 U.S. gallons in each of two reportable discharges in any 12-month period?[3]	☐ Yes ☐ No
If **YES**	• Was information submitted to the RA as required in §112.4(a)?[4]	☐ Yes ☐ No ☐ NA
	• Was information submitted to the appropriate agency or agencies in charge of oil pollution control activities in the State in which the facility is located§112.4(c)	☐ Yes ☐ No ☐ NA
	• Date(s) and volume(s) of reportable discharges(s) under this section:	
	• Were the discharges reported to the NRC[5]?	☐ Yes ☐ No
112.4(d),(e)	Have changes required by the RA been implemented in the Plan and/or facility?	☐ Yes ☐ No ☐ NA
Comments:		

AMENDMENT OF SPCC PLAN BY THE OWNER OR OPERATOR—40 CFR 112.5		
112.5(a)	Has there been a change at the facility that materially affects the potential for a discharge described in §112.1(b)?	☐ Yes ☐ No
If **YES**	• Was the Plan amended within six months of the change?	☐ Yes ☐ No
	• Were amendments implemented within six months of any Plan amendment?	☐ Yes ☐ No
112.5(b)	Review and evaluation of the Plan completed at least once every 5 years?	☐ Yes ☐ No ☐ NA
	Following Plan review, was Plan amended within six months to include more effective prevention and control technology that has been field-proven to significantly reduce the likelihood of a discharge described in §112.1(b)?	☐ Yes ☐ No ☐ NA
	Amendments implemented within six months of any Plan amendment?	☐ Yes ☐ No ☐ NA
	Five year Plan review and evaluation documented?	☐ Yes ☐ No ☐ NA
112.5(c)	Professional Engineer certification of any technical Plan amendments in accordance with all applicable requirements of §112.3(d) *[Except for self-certified Plans]*	☐ Yes ☐ No ☐ NA

Name:	License No.:	State:	Date of certification:
Reason for amendment:			
Comments:			

[3] A reportable discharge is a discharge as described in §112.1(b)(see 40 CFR part 110). The gallon amount(s) specified (either 1,000 or 42) refers to the amount of oil that actually reaches navigable waters or adjoining shorelines not the total amount of oil spilled. The entire volume of the discharge is oil for this determination

[4] Triggering this threshold may disqualify the facility from meeting the Qualified Facility criteria if it occurred in the three years prior to self-certification

[5] Inspector Note: Confirm any spills identified above were reported to NRC

GENERAL SPCC REQUIREMENTS—40 CFR 112.7		PLAN	FIELD
Management approval at a level of authority to commit the necessary resources to fully implement the Plan[6]		☐ Yes ☐ No	
Plan follows sequence of the rule or is an equivalent Plan meeting all applicable rule requirements and includes a cross-reference of provisions		☐ Yes ☐ No ☐ NA	
If Plan calls for facilities, procedures, methods, or equipment not yet fully operational, details of their installation and start-up are discussed *(Note: Relevant for inspection evaluation and testing baselines.)*		☐ Yes ☐ No ☐ NA	
112.7(a)(2)	The Plan includes deviations from the requirements of §§112.7(g), (h)(2) and (3), and (i) and applicable subparts B and C of the rule, except the secondary containment requirements in §§112.7(c) and (h)(1), 112.9(c)(2), 112.9(d)(3), and 112.10(c)	☐ Yes ☐ No ☐ NA	
If **YES**	• The Plan states reasons for nonconformance	☐ Yes ☐ No ☐ NA	
	• Alternative measures described in detail and provide equivalent environmental protection *(Note: Inspector should document if the environmental equivalence is implemented in the field, in accordance with the Plan's description)*	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA

Describe each deviation and reasons for nonconformance:

[6] May be part of the Plan or demonstrated elsewhere.

		PLAN	FIELD
112.7(a)(3)	Plan describes physical layout of facility and includes a diagram[7] that identifies: • Location and contents of all regulated fixed oil storage containers • Storage areas where mobile or portable containers are located • Completely buried tanks otherwise exempt from the SPCC requirements (marked as "exempt") • Transfer stations • Connecting pipes, including intra-facility gathering lines that are otherwise exempt from the requirements of this part under §112.1(d)(11)	☐ Yes ☐ No	☐ Yes ☐ No
	Plan addresses each of the following:		
(i)	For each fixed container, type of oil and storage capacity (see Attachment A of this checklist). For mobile or portable containers, type of oil and storage capacity for each container or an estimate of the potential number of mobile or portable containers, the types of oil, and anticipated storage capacities	☐ Yes ☐ No	☐ Yes ☐ No
(ii)	Discharge prevention measures, including procedures for routine handling of products (loading, unloading, and facility transfers, etc.)	☐ Yes ☐ No	☐ Yes ☐ No
(iii)	Discharge or drainage controls, such as secondary containment around containers, and other structures, equipment, and procedures for the control of a discharge	☐ Yes ☐ No	☐ Yes ☐ No
(iv)	Countermeasures for discharge discovery, response, and cleanup (both facility's and contractor's resources)	☐ Yes ☐ No	☐ Yes ☐ No
(v)	Methods of disposal of recovered materials in accordance with applicable legal requirements	☐ Yes ☐ No	
(vi)	Contact list and phone numbers for the facility response coordinator, National Response Center, cleanup contractors *with an agreement for response* , and all Federal, State, and local agencies who must be contacted in the case of a discharge as described in §112.1(b)	☐ Yes ☐ No	
112.7(a)(4)	***Does not apply if the facility has submitted an FRP under §112.20:*** ☐ Yes ☐ No ☐ NA Plan includes information and procedures that enable a person reporting an oil discharge as described in §112.1(b) to relate information on the: • Exact address or location and phone number of the facility; • Date and time of the discharge; • Type of material discharged; • Estimates of the total quantity discharged; • Estimates of the quantity discharged as described in §112.1(b); • Source of the discharge; • Description of all affected media; • Cause of the discharge; • Damages or injuries caused by the discharge; • Actions being used to stop, remove, and mitigate the effects of the discharge; • Whether an evacuation may be needed; and • Names of individuals and/or organizations who have also been contacted.		
112.7(a)(5)	***Does not apply if the facility has submitted a FRP under §112.20:*** Plan organized so that portions describing procedures to be used when a discharge occurs will be readily usable in an emergency	☐ Yes ☐ No ☐ NA	
112.7(b)	Plan includes a prediction of the direction, rate of flow, and total quantity of oil that could be discharged for each type of major equipment failure where experience indicates a reasonable potential for equipment failure	☐ Yes ☐ No ☐ NA	
Comments:			

[7] Note in comparing the plan to the field, the diagram, the description of the physical layout of facility, and what is observed in the field

		PLAN	FIELD
112.7(c)	Appropriate containment and/or diversionary structures or equipment are provided to prevent a discharge as described in §112.1(b), **except as provided in §112.7(k) of this section for certain qualified operational equipment and §112.9(d)(3) for certain flowlines and intra-facility gathering lines at an oil production facility**. The entire containment system, including walls and floors, are capable of containing oil and are constructed to prevent escape of a discharge from the containment system before cleanup occurs. The method, design, and capacity for secondary containment address the typical failure mode and the most likely quantity of oil that would be discharged. See Attachment A of this checklist. **For onshore facilities**, one of the following or its equivalent: • Dikes, berms, or retaining walls sufficiently impervious to contain oil, • Curbing or drip pans, • Sumps and collection systems, • Culverting, gutters or other drainage systems, • Weirs, booms or other barriers, • Spill diversion ponds, • Retention ponds, or • Sorbent materials.		
	Identify which of the following are present at the facility and if appropriate containment and/or diversionary structures or equipment are provided as described above:		
	☐ Bulk storage containers	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
	☐ Mobile/portable containers	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
	☐ Oil-filled operational equipment (as defined in 112.2)	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
	☐ Other oil-filled equipment (i.e., manufacturing equipment)	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
	☐ Piping and related appurtenances	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
	☐ Mobile refuelers of non-transportation-related tank cars	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
	☐ Transfer areas, equipment and activities	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
	☐ Identify any other equipment or activities that are not listed above:	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
112.7(d)	Secondary containment for one (or more) of the following provisions is determined to be impracticable: ☐ General secondary containment §112.7(c) ☐ Bulk storage containers §§112.8(c)(2)/112.12(c)(2) ☐ Loading/unloading rack §112.7(h)(1) ☐ Mobile/portable containers§§112.8(c)(11)/112.12(c)(11)	☐ Yes ☐ No	
If ***YES***	• The impracticability of secondary containment is clearly demonstrated and described in the Plan	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
	• For bulk storage containers,[8] periodic integrity testing of containers and integrity and leak testing of the associated valves and piping is conducted	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
	(Does not apply if the facility has submitted a FRP under §112.20): • Contingency Plan following the provisions of 40 CFR part 109 is provided (see Attachment C of this checklist) **AND**	☐ Yes ☐ No ☐ NA	
	• Written commitment of manpower, equipment, and materials required to expeditiously control and remove any quantity of oil discharged that may be harmful	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA

Comments:

[8] These additional requirements apply only to bulk storage containers, when an impracticability determination has been made by the PE

		PLAN	FIELD
112.7(e)	Inspections and tests conducted in accordance with written procedures	☐ Yes ☐ No	☐ Yes ☐ No
	Record of inspections or tests signed by supervisor or inspector	☐ Yes ☐ No	☐ Yes ☐ No
	Kept with Plan for at least 3 years (see Attachment B of this checklist)[9]	☐ Yes ☐ No	☐ Yes ☐ No
112.7(f)	Personnel, training, and oil discharge prevention procedures		
(1)	Training of oil-handling personnel in operation and maintenance of equipment to prevent discharges; discharge procedure protocols; applicable pollution control laws, rules, and regulations; general facility operations; and contents of SPCC Plan	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
(2)	Person designated as accountable for discharge prevention at the facility and reports to facility management	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
(3)	Discharge prevention briefings conducted at least once a year for oil handling personnel to assure adequate understanding of the Plan. Briefings highlight and describe known discharges as described in §112.1(b) or failures, malfunctioning components, and any recently developed precautionary measures	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
112.7(h)	Tank car and tank truck loading/unloading rack[10] is present at the facility		☐ Yes ☐ No
	Loading/unloading rack means a fixed structure (such as a platform, gangway) necessary for loading or unloading a tank truck or tank car, which is located at a facility subject to the requirements of this part. A loading/unloading rack includes a loading or unloading arm, and may include any combination of the following: piping assemblages, valves, pumps, shut-off devices, overfill sensors, or personnel safety devices.		
If YES (1)	Does loading/unloading rack drainage flow to catchment basin or treatment facility designed to handle discharges or use a quick drainage system?	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
	Containment system holds at least the maximum capacity of the largest single compartment of a tank car/truck loaded/unloaded at the facility	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
(2)	An interlocked warning light or physical barriers, warning signs, wheel chocks, or vehicle brake interlock system in the area adjacent to the **loading or unloading rack** to prevent vehicles from departing before complete disconnection of flexible or fixed oil transfer lines	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
(3)	Lower-most drains and all outlets on tank cars/trucks inspected prior to filling/departure, and, if necessary ensure that they are tightened, adjusted, or replaced to prevent liquid discharge while in transit	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA

Comments:

[9] Records of inspections and tests kept under usual and customary business practices will suffice

[10] Note that a tank car/truck loading/unloading rack must be present for §112.7(h) to apply

		PLAN	FIELD
112.7(i)	Brittle fracture evaluation of field-constructed aboveground containers is conducted after tank repair, alteration, reconstruction, or change in service that might affect the risk of a discharge or after a discharge/failure due to brittle fracture or other catastrophe, and appropriate action taken as necessary (applies to only field-constructed aboveground containers in production service, drilling, and workover service)	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
112.7(j)	Discussion of conformance with applicable more stringent State rules, regulations, and guidelines and other effective discharge prevention and containment procedures listed in 40 CFR part 112	☐ Yes ☐ No ☐ NA	
112.7(k)	Qualified oil-filled operational equipment is present at the facility[11] ☐ Yes ☐ No *Oil-filled operational equipment* means equipment that includes an oil storage container (or multiple containers) in which the oil is present solely to support the function of the apparatus or the device. Oil-filled operational equipment is not considered a bulk storage container, and does not include oil-filled manufacturing equipment (flow-through process). Examples of oil-filled operational equipment include, but are not limited to, hydraulic systems, lubricating systems (e.g. , those for pumps, compressors and other rotating equipment, including pumpjack lubrication systems), gear boxes, machining coolant systems, heat transfer systems, transformers, circuit breakers, electrical switches, and other systems containing oil solely to enable the operation of the device. If **YES** Check which apply: Secondary Containment provided in accordance with 112.7(c) ☐ Alternative measure described below (confirm eligibility) ☐		
112.7(k)	Qualified Oil-Filled Operational Equipment • Has a single reportable discharge as described in §112.1(b) from any oil-filled operational equipment exceeding 1,000 U.S. gallons occurred within the three years prior to Plan certification date? ☐ Yes ☐ No ☐ NA • Have two reportable discharges as described in §112.1(b) from any oil-filled operational equipment each exceeding 42 U.S. gallons occurred within any 12-month period within the three years prior to Plan certification date?[12] ☐ Yes ☐ No ☐ NA		
	*If **YES** for either, secondary containment in accordance with §112.7(c) is required*		
	• Facility procedure for inspections or monitoring program to detect equipment failure and/or a discharge is established and documented	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
	Does not apply if the facility has submitted a FRP under §112.20: • Contingency plan following 40 CFR part 109 (see Attachment C of this checklist) is provided in Plan **AND**	☐ Yes ☐ No ☐ NA	
	• Written commitment of manpower, equipment, and materials required to expeditiously control and remove any quantity of oil discharged that may be harmful is provided in Plan	☐ Yes ☐ No ☐ NA	
Comments:			

[11] This provision does not apply to oil-filled manufacturing equipment (flow-through process)

[12] Oil discharges that result from natural disasters, acts of war, or terrorism are not included in this determination. The gallon amount(s) specified (either 1,000 or 42) refers to the amount of oil that actually reaches navigable waters or adjoining shorelines not the total amount of oil spilled. The entire volume of oil discharged is not the determining factor.

ONSHORE OIL PRODUCTION FACILITIES—40 CFR 112.9 ☐ NA		PLAN	FIELD
(Drilling and workover facilities are excluded from the requirements of §112.9) *Production facility* means all structures (including but not limited to wells, platforms, or storage facilities), piping (including but not limited to flowlines or intra-facility gathering lines), or equipment (including but not limited to workover equipment, separation equipment, or auxiliary non-transportation-related equipment) used in the production, extraction, recovery, lifting, stabilization, separation or treating of oil (including condensate), or associated storage or measurement, and is located in an oil or gas field, at a facility. This definition governs whether such structures, piping, or equipment are subject to a specific section of this part.			
112.9(b) Oil Production Facility Drainage			
(1)	At tank batteries, separation and treating areas where there is a reasonable possibility of a discharge as described in §112.1(b), drains for dikes or equivalent measures are closed and sealed except when draining uncontaminated rainwater. Accumulated oil on the rainwater is removed and then returned to storage or disposed of in accordance with legally approved methods	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
	Prior to drainage, diked area inspected and action taken as provided below:		
	• 112.8(c)(3)(ii) - Retained rainwater is inspected to ensure that its presence will not cause a discharge as described in §112.1(b)	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
	• 112.8(c)(3)(iii) - Bypass valve opened and resealed under responsible supervision	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
	• 112.8(c)(3)(iv) - Adequate records of drainage are kept; for example, records required under permits issued in accordance with §122.41(j)(2) and (m)(3)	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
(2)	Field drainage systems (e.g., drainage ditches or road ditches) and oil traps, sumps, or skimmers inspected at regularly scheduled intervals for oil, and accumulations of oil promptly removed	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
112.9(c) Oil Production Facility Bulk Storage Containers *Bulk storage container* means any container used to store oil. These containers are used for purposes including, but not limited to, the storage of oil prior to use, while being used, or prior to further distribution in commerce. Oil-filled electrical, operating, or manufacturing equipment is not a bulk storage container.			
(1)	Containers materials and construction are compatible with material stored and conditions of storage such as pressure and temperature	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
(2)	Except as allowed for flow-through process vessels in §112.9(c)(5) and produced water containers in §112.9(c)(6), secondary containment provided for all tank battery, separation and treating facilities sized to hold the capacity of largest single container and sufficient freeboard for precipitation.	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
	Drainage from undiked area safely confined in a catchment basin or holding pond.	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
(3)	Except as allowed for flow-through process vessels in §112.9(c)(5) and produced water containers in §112.9(c)(6), periodically and upon a regular schedule, visually inspect containers for deterioration and maintenance needs, including foundation and supports of each container on or above the surface of the ground	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
(4)	New and old tank batteries engineered/updated in accordance with good engineering practices to prevent discharges including at least one of the following: • Adequate container capacity to prevent overfill if a pumper/gauger is delayed in making regularly scheduled rounds; • Overflow equalizing lines between containers so that a full container can overflow to an adjacent container; • Adequate vacuum protection to prevent container collapse; or • High level sensors to generate and transmit an alarm to the computer where the facility is subject to a computer production control system	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
Comments:			

		PLAN	FIELD
(5)	**Flow-through Process Vessels.** Alternate requirements in lieu of sized secondary containment required in (c)(2) and requirements in (c)(3) above for facilities with flow-through process vessels:		
(i)	Flow-through process vessels and associated components (e.g. dump valves) are periodically and on a regular schedule visually inspected and/or tested for leaks, corrosion, or other conditions that could lead to a discharge as described in §112.1(b)	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
(ii)	Corrective actions or repairs have been made to flow-through process vessels and any associated components as indicated by regularly scheduled visual inspections, tests, or evidence of an oil discharge	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
(iii)	Oil removed or other actions initiated to promptly stabilize and remediate any accumulation of oil discharges associated with the produced water container	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
(iv)	All flow-through process vessels comply with §§112.9(c)(2) and (c)(3) within six months of any flow-through process vessel discharge of more than 1,000 U.S. gallons of oil in a single discharge as described in §112.1(b) or discharges of more than 42 U.S. gallons of oil in each of two discharges as described in §112.1(b) within any twelve month period.[13]	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
(6)	**Produced Water Containers.** Alternate requirements in lieu of sized secondary containment required in (c)(2) and requirements in (c)(3) above for facilities with produced water containers:		
(i)	A procedure is implemented on a regular schedule for each produced water container that is designed to separate the free-phase oil that accumulates on the surface of the produced water.	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
	• A description is included in the Plan of the procedures, frequency, and amount of free-phase oil expected to be maintained inside the container;	☐ Yes ☐ No ☐ NA	
	• PE certifies in accordance with §112.3(d)(1)(vi);	☐ Yes ☐ No ☐ NA	
	• Records of such events are maintained in accordance with §112.7(e).	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
	If this procedure is not implemented as described in the Plan or no records are maintained, then facility owner/operator must comply with §112.9(c)(2) and (c)(3).		
(ii)	Each produced water container and associated piping is visually inspected, on a regular basis, for leaks, corrosion, or other conditions that could lead to a discharge as described in §112.1(b) in accordance with good engineering practice.	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
(iii)	Corrective action or necessary repairs were made to any produced water container and associated piping as indicated by regularly scheduled visual inspections, tests, or evidence of an oil discharge.	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
(iv)	Oil removed or other actions initiated to promptly stabilize and remediate any accumulation of oil discharges associated with the produced water container.	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
(v)	All produced water containers comply with §§112.9(c)(2) and (c)(3) within six months of any produced water container discharge of more than 1,000 U.S. gallons of oil in a single discharge as described in §112.1(b) or discharges of more than 42 U.S. gallons of oil in each of two discharges as described in §112.1(b) within any twelve month period.[13]	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
Comments:			

[13] Oil discharges that result from natural disasters, acts of war, or terrorism are not included in this determination. The gallon amount(s) specified (either 1,000 or 42) refers to the amount of oil that actually reaches navigable waters or adjoining shorelines not the total amount of oil spilled. The entire volume of spilled oil is not included.

		PLAN	FIELD
112.9(d) Facility transfer operations, pumping, and facility process			
(1)	All aboveground valves and piping associated with transfer operations are inspected periodically and upon a regular schedule to determine their general condition. Include the general condition of flange joints, valve glands and bodies, drip pans, pipe supports, pumping well polish rod stuffing boxes, bleeder and gauge valves, and other such items	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
(2)	Saltwater (oil field brine) disposal facilities inspected often to detect possible system upsets capable of causing a discharge, particularly following a sudden change in atmospheric temperature	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
(3)	If flowlines and intra-facility gathering lines are not provided with secondary containment in accordance with §112.7(c) and the facility is not required to submit an FRP under §112.20, then the SPCC Plan includes:		
(i)	• An oil spill contingency plan following the provisions of 40 CFR part 109[14]	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
(ii)	• A written commitment of manpower, equipment, and materials required to expeditiously control and remove any quantity of oil discharged that might be harmful	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
(4)	A flowline/intra-facility gathering line maintenance program to prevent discharges is prepared and implemented and includes the following procedures:		
(i)	Flowlines and intra-facility gathering lines and associated valves and equipment are compatible with the type of production fluids, their potential corrosivity, volume, and pressure, and other conditions expected in the operational environment	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
(ii)	Flowlines and intra-facility gathering lines and associated appurtenances are visually inspected and/or tested on a periodic and regular schedule for leaks, oil discharges, corrosion, or other conditions that could lead to a discharge as described in §112.1(b).	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
	If flowlines and intra-facility gathering lines are not provided with secondary containment in accordance with §112.7(c), the frequency and type of testing allows for the implementation of a contingency plan as described under 40 CFR 109 or an FRP submitted under §112.20	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
(iii)	Repairs or other corrective actions are made to any flowlines and intra-facility gathering lines and associated appurtenances as indicated by regularly scheduled visual inspections, tests, or evidence of a discharge	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
(iv)	Oil removed or other actions initiated to promptly stabilize and remediate any accumulations of oil discharges associated with the flowlines, intra-facility gathering lines, and associated appurtenances	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
ONSHORE OIL DRILLING AND WORKOVER FACILITIES—40 CFR 112.10			☐ NA
112.10(b)	Mobile drilling or workover equipment is positioned or located to prevent a discharge as described in §112.1(b)	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
112.10(c)	Catchment basins or diversion structures are provided to intercept and contain discharges of fuel, crude oil, or oily drilling fluids	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
112.10(d)	Blowout prevention (BOP) assembly and well control system installed before drilling below any casing string or during workover operations	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
	BOP assembly and well control system is capable of controlling any well-head pressure that may be encountered while on the well	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
Comments:			

[14] Note that the Guidance for a 40 CFR part 109 plan does not require a PE impracticability determination for this specific requirement.

This page left intentionally blank.

ATTACHMENT A: SPCC FIELD INSPECTION AND PLAN REVIEW TABLE

Documentation of Field Observations for Containers and Associated Requirements

Inspectors should use this table to document observations of containers as needed.

Containers and Piping

Check containers for leaks, specifically looking for: drip marks, discoloration of tanks, puddles containing spilled or leaked material, corrosion, cracks, and localized dead vegetation, and standards/specifications of construction.

Check aboveground container foundation for: cracks, discoloration, and puddles containing spilled or leaked material, settling, gaps between container and foundation, and damage caused by vegetation roots.

Check all piping for: droplets of stored material, discoloration, corrosion, bowing of pipe between supports, evidence of stored material seepage from valves or seals, evidence of leaks, and localized dead vegetation. For all aboveground piping, include the general condition of flange joints, valve glands and bodies, drip pans, pipe supports, bleeder and gauge valves, and other such items (Document in comments section of §112.9(d).)

Secondary Containment (Active and Passive)

Check secondary containment for: containment system (including walls and floor) ability to contain oil such that oil will not escape the containment system before cleanup occurs, proper sizing, cracks, discoloration, presence of spilled or leaked material (standing liquid), erosion, corrosion, penetrations in the containment system, and valve conditions.

Check dike or berm systems for: level of precipitation in dike/available capacity, operational status of drainage valves (closed), dike or berm impermeability, debris, erosion, impermeability of the earthen floor/walls of diked area, and location/status of pipes, inlets, drainage around and beneath containers, presence of oil discharges within diked areas.

Check drainage systems for: an accumulation of oil that may have resulted from any small discharge, including field drainage systems (such as drainage ditches or road ditches), and oil traps, sumps, or skimmers. Ensure any accumulations of oil have been promptly removed.

Check retention and drainage ponds for: erosion, available capacity, presence of spilled or leaked material, debris, and stressed vegetation.

Check active measures (countermeasures) for: amount indicated in plan is available and appropriate; deployment procedures are realistic; material is located so that they are readily available; efficacy of discharge detection; availability of personnel and training, appropriateness of measures to prevent a discharge as described in §112.1(b). *Note that appropriate evaluation and consideration must be given to the any use of active measures at an unmanned oil production facility.*

Container ID/ General Condition[15] Aboveground or Buried Tank	Storage Capacity and Type of Oil	Type of Containment/ Drainage Control	Overfill Protection and Testing & Inspections

[15] Identify SPCC Guidance for Regional Inspectors or B for completely buried

ATTACHMENT A: SPCC FIELD INSPECTION AND PLAN REVIEW TABLE (CONT.)

Documentation of Field Observations for Containers and Associated Requirements

Container ID/ General Condition[16] Aboveground or Buried Tank	Storage Capacity and Type of Oil	Type of Containment/ Drainage Control	Overfill Protection and Testing & Inspections

[16] Identify each container as A for aboveground or B for completely buried

ATTACHMENT B: SPCC INSPECTION AND TESTING CHECKLIST

Required Documentation of Tests and Inspections

Records of inspections and tests required by 40 CFR part 112 signed by the appropriate supervisor or inspector must be kept by all facilities with the SPCC Plan for a period of three years. Records of inspections and tests conducted under usual and customary business practices will suffice. Documentation of the following inspections and tests should be kept with the SPCC Plan.

	Inspection or Test	Documentation		Not Applicable
		Present	Not Present	
112.7–General SPCC Requirements				
(d)	Integrity testing for bulk storage containers with no secondary containment system and for which an impracticability determination has been made	☐	☐	☐
(d)	Integrity and leak testing of valves and piping associated with bulk storage containers with no secondary containment system and for which an impracticability determination has been made	☐	☐	☐
(h)(3)	Inspection of lowermost drain and all outlets of tank car or tank truck prior to filling and departure from loading/unloading rack	☐	☐	☐
(i)	Evaluation of field-constructed aboveground containers for potential for brittle fracture or other catastrophic failure when the container undergoes a repair, alteration, reconstruction or change in service or has discharged oil or failed due to brittle fracture failure or other catastrophe	☐	☐	☐
k(2)(i)	Inspection or monitoring of qualified oil-filled operational equipment when the equipment meets the qualification criteria in §112.7(k)(1) and facility owner/operator chooses to implement the alternative requirements in §112.7(k)(2) that include an inspection or monitoring program to detect oil-filled operational equipment failure and discharges	☐	☐	☐
112.9–Onshore Oil Production Facilities (excluding drilling and workover facilities)				☐ NA
(b)(1)	Rainwater released directly from diked containment areas inspected following §§112.8(c)(3)(ii), (iii) and (iv), including records of drainage kept	☐	☐	☐
(b)(2)	Field drainage systems, oil traps, sumps, and skimmers inspected regularly for oil, and accumulations of oil promptly removed	☐	☐	☐
(c)(3)	Containers, foundations and supports inspected visually for deterioration and maintenance needs	☐	☐	☐
(c)(5)(i)	In lieu of having sized secondary containment, flow-through process vessels and associated components visually inspected and/or tested periodically and on a regular schedule for conditions that could result in a discharge as described in §112.1(b)	☐	☐	☐
(c)(6)(ii)	In lieu of having sized secondary containment, produced water containers and associated piping are visually inspected and/or tested for leaks, corrosion, or other conditions that could lead to a discharge as described in §112.1(b) in accordance with good engineering practice	☐	☐	☐
(d)(1)	All aboveground valves and piping associated with transfer operations are regularly inspected	☐	☐	☐
(d)(2)	Saltwater disposal facilities inspected often to detect possible system upsets capable of causing a discharge	☐	☐	☐
(d)(4)(ii)	For flowlines and intra-facility gathering lines without secondary containment, in accordance with §112.7(c), lines are visually inspected and/or tested periodically and on a regular schedule to allow implementing the part 109 contingency plan or the FRP submitted under §112.20	☐	☐	☐

This page left intentionally blank.

ATTACHMENT C: SPCC CONTINGENCY PLAN REVIEW CHECKLIST ☐ NA

40 CFR Part 109–Criteria for State, Local and Regional Oil Removal Contingency Plans

If SPCC Plan includes an impracticability determination for secondary containment in accordance with §112.7(d), the facility owner/operator is required to provide an oil spill contingency plan following 40 CFR part 109, unless he or she has submitted a FRP under §112.20. An oil spill contingency plan may also be developed, unless the facility owner/operator has submitted a FRP under §112.20 as one of the required alternatives to general secondary containment for qualified oil filled operational equipment in accordance with §112.7(k).

109.5–Development and implementation criteria for State, local and regional oil removal contingency plans[17]		Yes	No
(a)	Definition of the authorities, responsibilities and duties of all persons, organizations or agencies which are to be involved in planning or directing oil removal operations.	☐	☐
(b)	Establishment of notification procedures for the purpose of early detection and timely notification of an oil discharge including:	☐	☐
(1)	The identification of critical water use areas to facilitate the reporting of and response to oil discharges.	☐	☐
(2)	A current list of names, telephone numbers and addresses of the responsible persons (with alternates) and organizations to be notified when an oil discharge is discovered.	☐	☐
(3)	Provisions for access to a reliable communications system for timely notification of an oil discharge, and the capability of interconnection with the communications systems established under related oil removal contingency plans, particularly State and National plans (e.g., National Contingency Plan (NCP)).	☐	☐
(4)	An established, prearranged procedure for requesting assistance during a major disaster or when the situation exceeds the response capability of the State, local or regional authority.	☐	☐
(c)	Provisions to assure that full resource capability is known and can be committed during an oil discharge situation including:	☐	☐
(1)	The identification and inventory of applicable equipment, materials and supplies which are available locally and regionally.	☐	☐
(2)	An estimate of the equipment, materials and supplies that would be required to remove the maximum oil discharge to be anticipated.	☐	☐
(3)	Development of agreements and arrangements in advance of an oil discharge for the acquisition of equipment, materials and supplies to be used in responding to such a discharge.	☐	☐
(d)	Provisions for well defined and specific actions to be taken after discovery and notification of an oil discharge including:	☐	☐
(1)	Specification of an oil discharge response operating team consisting of trained, prepared and available operating personnel.	☐	☐
(2)	Pre-designation of a properly qualified oil discharge response coordinator who is charged with the responsibility and delegated commensurate authority for directing and coordinating response operations and who knows how to request assistance from Federal authorities operating under existing national and regional contingency plans.	☐	☐
(3)	A preplanned location for an oil discharge response operations center and a reliable communications system for directing the coordinated overall response operations.	☐	☐
(4)	Provisions for varying degrees of response effort depending on the severity of the oil discharge.	☐	☐
(5)	Specification of the order of priority in which the various water uses are to be protected where more than one water use may be adversely affected as a result of an oil discharge and where response operations may not be adequate to protect all uses.	☐	☐
(e)	Specific and well defined procedures to facilitate recovery of damages and enforcement measures as provided for by State and local statutes and ordinances.	☐	☐

[17] The contingency plan shall be consistent with applicable state and local plans, Area Contingency Plans, and the NCP.

This page left intentionally blank.

ATTACHMENT D: TIER II QUALIFIED FACILITY CHECKLIST ☐ NA

TIER II QUALIFIED FACILITY PLAN REQUIREMENTS —40 CFR 112.6(b)		
112.6(b)(1)	**Plan Certification:** Owner/operator certified in the Plan that:	☐ Yes ☐ No
(i)	He or she is familiar with the requirements of 40 CFR part 112	☐ Yes ☐ No ☐ NA
(ii)	He or she has visited and examined the facility[18]	☐ Yes ☐ No ☐ NA
(iii)	The Plan has been prepared in accordance with accepted and sound industry practices and standards and with the requirements of this part	☐ Yes ☐ No ☐ NA
(iv)	Procedures for required inspections and testing have been established	☐ Yes ☐ No ☐ NA
(v)	He or she will fully implement the Plan	☐ Yes ☐ No ☐ NA
(vi)	The facility meets the qualification criteria set forth under §112.3(g)(2)	☐ Yes ☐ No ☐ NA
(vii)	The Plan does not deviate from any requirements as allowed by §§112.7(a)(2) and 112.7(d), except as described under §112.6(b)(3)(i) or (ii)	☐ Yes ☐ No ☐ NA
(viii)	The Plan and individual(s) responsible for implementing the Plan have the full approval of management and the facility owner or operator has committed the necessary resources to fully implement the Plan.	☐ Yes ☐ No ☐ NA
112.6(b)(2)	**Technical Amendments:** The owner/operator self-certified the Plan's technical amendments for a change in facility design, construction, operation, or maintenance that affected potential for a §112.1(b) discharge	☐ Yes ☐ No ☐ NA
If **YES**	• Certification of technical amendments is in accordance with the self-certification provisions of §112.6(b)(1).	☐ Yes ☐ No ☐ NA
(i)	A PE certified a portion of the Plan (i.e., Plan is informally referred to as a hybrid Plan)	☐ Yes ☐ No ☐ NA
If **YES**	• The PE also certified technical amendments that affect the PE certified portion of the Plan as required under §112.6(b)(4)(ii)	☐ Yes ☐ No ☐ NA
(ii)	The aggregate aboveground oil storage capacity increased to more than 10,000 U.S. gallons as a result of the change	☐ Yes ☐ No ☐ NA
If **YES**	*The facility no longer meets the Tier II qualifying criteria in §112.3(g)(2) because it exceeds 10,000 U.S. gallons in aggregate aboveground storage capacity.*	
	The owner/operator prepared and implemented a Plan within 6 months following the change and had it certified by a PE under §112.3(d)	☐ Yes ☐ No ☐ NA
112.6(b)(3)	**Plan Deviations:** Does the Plan include environmentally equivalent alternative methods or impracticability determinations for secondary containment?	☐ Yes ☐ No ☐ NA
If **YES**	Identify the alternatives in the hybrid Plan:	
	• Environmental equivalent alternative method(s) allowed under §112.7(a)(2);	☐ Yes ☐ No ☐ NA
	• Impracticability determination under §112.7(d)	☐ Yes ☐ No ☐ NA
112.6(b)(4)	• For each environmentally equivalent measure, the Plan is accompanied by a written statement by the PE that describes: the reason for nonconformance, the alternative measure, and how it offers equivalent environmental protection in accordance with §112.7(a)(2);	☐ Yes ☐ No ☐ NA
	• For each secondary containment impracticability determination, the Plan explains the reason for the impracticability determination and provides the alternative measures to secondary containment required in §112.7(d)	☐ Yes ☐ No ☐ NA
	AND	
(i)	PE certifies in the Plan that:	
(A)	He/she is familiar with the requirements of 40 CFR Part 112	☐ Yes ☐ No ☐ NA
(B)	He/she or a representative agent has visited and examined the facility	☐ Yes ☐ No ☐ NA
(C)	The alternative method of environmental equivalence in accordance with §112.7(a)(2) or the determination of impracticability and alternative measures in accordance with §112.7(d) is consistent with good engineering practice, including consideration of applicable industry standards, and with the requirements of 40 CFR Part 112.	☐ Yes ☐ No ☐ NA

Comments:

[18] Note that only the PE may fulfill this requirement for a site visit

This page left intentionally blank.

ATTACHMENT E: ADDITIONAL COMMENTS

ATTACHMENT E: ADDITIONAL COMMENTS (CONT.)

ATTACHMENT F: PHOTO DOCUMENTATION NOTES

Photo#	Photographer Name	Time of Photo Taken	Compass Direction	Description

ATTACHMENT F: PHOTO DOCUMENTATION NOTES (CONT.)

Photo#	Photographer Name	Time of Photo Taken	Compass Direction	Description

ENVIRONMENTAL PROTECTION AGENCY
SPCC FIELD INSPECTION AND PLAN REVIEW CHECKLIST

OFFSHORE OIL DRILLING, PRODUCTION AND WORKOVER FACILITIES

Overview of the Checklist

This checklist is designed to assist EPA inspectors in conducting a thorough and nationally consistent inspection of a facility's compliance with the Spill Prevention, Control, and Countermeasure (SPCC) rule at 40 CFR part 112. It is a required tool to help federal inspectors (or their contractors) record observations for the site inspection and review of the SPCC Plan. While the checklist is meant to be comprehensive, the inspector should always refer to the SPCC rule in its entirety, the SPCC Regional Inspector Guidance Document, and other relevant guidance for evaluating compliance. This checklist must be completed in order for an inspection to count toward an agency measure (i.e., OEM inspection measures or GPRA). The completed checklist and supporting documentation (i.e. photo logs or additional notes) serve as the inspection report.

This checklist addresses requirements for offshore oil production, drilling, and workover facilities.

Separate and standalone checklists address the requirements for:
Onshore facilities including Tier II Qualified Facilities (excluding oil drilling, production and workover facilities);
Onshore oil drilling, production and workover facilities including Tier II Qualified Facilities as defined in §112.3(g)(2); and
Tier I Qualified Facilities (for facilities that meet the eligibility criteria defined in §112.3(g)(1)).

Qualified facilities must meet the rule requirements in §112.6 and other applicable sections specified in §112.6, except for deviations that provide environmental equivalence and secondary containment impracticability determinations as allowed under §112.6.

The checklist is organized according to the SPCC rule. Each item in the checklist identifies the relevant section and paragraph in 40 CFR part 112 where that requirement is stated.

- Sections 112.1 through 112.5 specify the applicability of the rule and requirements for the preparation, implementation, and amendment of SPCC Plans. For these sections, the checklist includes data fields to be completed, as well as several questions with "yes," "no" or "NA" answers.
- Section 112.7 includes general requirements that apply to all facilities (unless otherwise excluded).
- Section 112.11 specifies spill prevention, control, and countermeasures requirements for offshore oil drilling, production and workover facilities.

The inspector needs to evaluate whether the requirement is addressed adequately or inadequately in the SPCC Plan and whether it is implemented adequately in the field (either by field observation or record review). For the SPCC Plan and implementation in the field, if a requirement is addressed adequately, mark the "Yes" box in the appropriate column. If a requirement is not addressed adequately, mark the "No" box. If a requirement does not apply to the particular facility or the question asked is not appropriate for the facility, mark as "NA". Discrepancies or descriptions of inspector interpretation of "No" vs. "NA" may be documented in the comments box subsequent to each section. If a provision of the rule applies only to the SPCC Plan, the "Field" column is shaded.

Space is provided throughout the checklist to record comments. Additional space is available as Attachment D at the end of the checklist. Comments should remain factual and support the evaluation of compliance.

<u>Attachments</u> (Attachments A and B are included for hybrid facilities which have both offshore and onshore components)

- Attachment A is a checklist for Sections 112.8 and 112.12. This checklist specifies requirements for spill prevention, control, and countermeasures for onshore facilities (excluding oil production facilities).
- Attachment B is a checklist that specifies requirements for spill prevention, control, and countermeasures for onshore oil production facilities (112.9 provisions) and onshore drilling and workover facilities (112.10 provisions)
- Attachment C is for recording information about containers and other locations at the facility that require secondary containment.
- Attachment D is a checklist for documentation of the tests and inspections the facility operator is required to keep with the SPCC Plan.
- Attachment E is a checklist for oil spill contingency plans following 40 CFR 109. Unless a facility has submitted a Facility Response Plan (FRP) under 40 CFR 112.20, a contingency plan following 40 CFR 109 is required if a facility determines that secondary containment is impracticable as provided in 40 CFR 112.7(d). The same requirement for an oil spill contingency plan applies to the owner or operator of a facility with qualified oil-filled operational equipment that chooses to implement alternative requirements instead of general secondary containment requirements as provided in 40 CFR 112.7(k).
- Attachment F is for recording additional comments or notes.
- Attachment G is for recording information about photos.

FACILITY INFORMATION			
FACILITY NAME:			
LATITUDE:	LONGITUDE:	GPS DATUM:	
Section/Township/Range:	FRS#/OIL DATABASE ID:	ICIS#:	
ADDRESS:			
CITY:	STATE:	ZIP:	COUNTY:
MAILING ADDRESS (IF DIFFERENT FROM FACILITY ADDRESS – IF NOT, PRINT "SAME"):			
CITY:	STATE:	ZIP:	COUNTY:
TELEPHONE:	FACILITY CONTACT NAME/TITLE:		
OWNER NAME:			
OWNER ADDRESS:			
CITY:	STATE:	ZIP:	COUNTY:
TELEPHONE:	FAX:	EMAIL:	
FACILITY OPERATOR NAME (IF DIFFERENT FROM OWNER – IF NOT, PRINT "SAME"):			
OPERATOR ADDRESS:			
CITY:	STATE:	ZIP:	COUNTY:
TELEPHONE:	OPERATOR CONTACT NAME/TITLE:		
FACILITY TYPE:			NAICS CODE:
HOURS PER DAY FACILITY ATTENDED:	TOTAL FACILITY CAPACITY:		
TYPE(S) OF OIL STORED:			
LOCATED IN INDIAN COUNTRY? ☐ YES ☐ NO RESERVATION NAME:			

INSPECTION/PLAN REVIEW INFORMATION		
PLAN REVIEW DATE:	REVIEWER NAME:	
INSPECTION DATE:	TIME:	ACTIVITY ID NO:
LEAD INSPECTOR:		
OTHER INSPECTOR(S):		

INSPECTION ACKNOWLEDGMENT	
I performed an SPCC inspection at the facility specified above.	
INSPECTOR SIGNATURE:	DATE:
SUPERVISOR REVIEW/SIGNATURE:	DATE:

SPCC GENERAL APPLICABILITY—40 CFR 112.1

IS THE FACILITY REGULATED UNDER 40 CFR part 112?

The completely buried oil storage capacity is over 42,000 U.S. gallons, **OR** the aggregate aboveground oil storage capacity is over 1,320 U.S. gallons **AND** ☐ Yes ☐ No

The facility is a non-transportation-related facility engaged in drilling, producing, gathering, storing, processing, refining, transferring, distributing, using, or consuming oil and oil products, which due to its location could reasonably be expected to discharge oil into or upon the navigable waters of the United States ☐ Yes ☐ No

AFFECTED WATERWAY(S):	DISTANCE:

FLOW PATH TO WATERWAY:

Note: The following storage capacity is not considered in determining applicability of SPCC requirements:

- *Equipment subject to the authority of the U.S. Department of Transportation, U.S. Department of the Interior, or Minerals Management Service, as defined in Memoranda of Understanding dated November 24, 1971, and November 8, 1993; Tank trucks that return to an otherwise regulated facility that contain only residual amounts of oil (EPA Policy letter)*
- *Completely buried tanks subject to all the technical requirements of 40 CFR part 280 or a state program approved under 40 CFR part 281;*
- *Underground oil storage tanks deferred under 40 CFR part 280 that supply emergency diesel generators at a nuclear power generation facility licensed by the Nuclear Regulatory Commission (NRC) and subject to any NRC provision regarding design and quality criteria, including but not limited to CFR part 50;*
- *Any facility or part thereof used exclusively for wastewater treatment (production, recovery or recycling of oil is not considered wastewater treatment); (This does not include other oil containers located at a wastewater treatment facility, such as generator tanks or transformers)*
- *Containers smaller than 55 U.S. gallons;*
- *Permanently closed containers (as defined in §112.2);*
- *Motive power containers (as defined in §112.2);*
- *Hot-mix asphalt or any hot-mix asphalt containers;*
- *Heating oil containers used solely at a single-family residence;*
- *Pesticide application equipment and related mix containers;*
- *Any milk and milk product container and associated piping and appurtenances; and*
- *Intra-facility gathering lines subject to the regulatory requirements of 49 CFR part 192 or 195.*

Does the facility have an SPCC Plan? ☐ Yes ☐ No

FACILITY RESPONSE PLAN (FRP) APPLICABILITY —40 CFR 112.20(f)

A non-transportation related onshore facility is required to prepare and implement an FRP as outlined in 40 CFR 112.20 if:

- ☐ The facility transfers oil over water to or from vessels and has a total oil storage capacity greater than or equal to 42,000 U.S. gallons, **OR**
- ☐ The facility has a total oil storage capacity of at least 1 million U.S. gallons, **AND** at least one of the following is true:
  - ☐ The facility does not have secondary containment sufficiently large to contain the capacity of the largest aboveground tank plus sufficient freeboard for precipitation.
  - ☐ The facility is located at a distance such that a discharge could cause injury to fish and wildlife and sensitive environments.
  - ☐ The facility is located such that a discharge would shut down a public drinking water intake.
  - ☐ The facility has had a reportable discharge greater than or equal to 10,000 U.S. gallons in the past 5 years.

Facility has FRP: ☐ Yes ☐ No ☐ NA	FRP Number:

Facility has a completed and signed copy of Appendix C, Attachment C-II, "Certification of the Applicability of the Substantial Harm Criteria." ☐ Yes ☐ No

Comments:

REQUIREMENTS FOR PREPARATION AND IMPLEMENTATION OF A SPCC PLAN—40 CFR 112.3		
Date facility began operations:		
Date of initial SPCC Plan preparation:	Current Plan version (date/number):	
112.3(a)	**For drilling, production or workover facilities, including mobile or portable facilities, that are offshore or have an offshore component; or facilities required to have and submit a FRP:** • In operation on or prior to November 10, 2010: Plan prepared and/or amended and fully implemented by **November 10, 2010** • Facilities beginning operation after November 10, 2010: o Plan prepared and fully implemented before drilling and workover facilities begin operations; or o Plan prepared and fully implemented within six months after oil production facilities begin operations	☐ Yes ☐ No ☐ NA ☐ Yes ☐ No ☐ NA ☐ Yes ☐ No ☐ NA
112.3(d)	Plan is certified by a registered Professional Engineer (PE) and includes statements that the PE attests: • PE is familiar with the requirements of 40 CFR part 112 • PE or agent has visited and examined the facility • Plan is prepared in accordance with good engineering practice including consideration of applicable industry standards and the requirements of 40 CFR part 112 • Procedures for required inspections and testing have been established • Plan is adequate for the facility • For produced water containers subject to 112.9(c)(6), any procedure to minimize the amount of free-phase oil is designed to reduce the accumulation of free-phase oil and the procedures and frequency for required inspections, maintenance and testing have been established and are described in the Plan, if applicable	☐ Yes ☐ No ☐ NA ☐ Yes ☐ No ☐ NA ☐ Yes ☐ No ☐ NA ☐ Yes ☐ No ☐ NA ☐ Yes ☐ No ☐ NA ☐ Yes ☐ No ☐ NA ☐ Yes ☐ No ☐ NA

PE Name:	License No.:	State:	Date of certification:

112.3(e)(1)	Plan is available onsite if attended at least 4 hours per day. If facility is unattended, Plan is available at the nearest field office. *(Please note nearest field office contact information in comments section below.)*	☐ Yes ☐ No ☐ NA

AMENDMENT OF SPCC PLAN BY REGIONAL ADMINISTRATOR (RA)—40 CFR 112.4		
112.4(a),(c)	Has the facility discharged more than 1,000 U.S. gallons of oil in a single reportable discharge or more than 42 U.S. gallons in each of two reportable discharges in any 12-month period?[1]	☐ Yes ☐ No
If **YES**	• Was information submitted to the RA as required in §112.4(a)?[2] • Was information submitted to the appropriate agency or agencies in charge of oil pollution control activities in the State in which the facility is located§112.4(c) • Date(s) and volume(s) of reportable discharges(s) under this section: • Were the discharges reported to the NRC[3]?	☐ Yes ☐ No ☐ NA ☐ Yes ☐ No ☐ NA ☐ Yes ☐ No
112.4(d),(e)	Have changes required by the RA been implemented in the Plan and/or facility?	☐ Yes ☐ No ☐ NA

Comments:

[1] A reportable discharge is a discharge as described in §112.1(b)(see 40 CFR part 110). The gallon amount(s) specified (either 1,000 or 42) refers to the amount of oil that actually reaches navigable waters or adjoining shorelines not the total amount of oil spilled. The entire volume of the discharge is oil for this determination.

[2] Triggering this threshold may disqualify the facility from meeting the Qualified Facility criteria if it occurred in the three years prior to self certification

[3] Inspector Note-Confirm any spills identified above were reported to NRC

AMENDMENT OF SPCC PLAN BY THE OWNER OR OPERATOR—40 CFR 112.5		
112.5(a)	Has there been a change at the facility that materially affects the potential for a discharge described in §112.1(b)?	☐ Yes ☐ No
If **YES**	• Was the Plan amended within six months of the change?	☐ Yes ☐ No
	• Were amendments implemented within six months of any Plan amendment?	☐ Yes ☐ No
112.5(b)	Review and evaluation of the Plan completed at least once every 5 years?	☐ Yes ☐ No ☐ NA
	Following Plan review, was Plan amended within six months to include more effective prevention and control technology that has been field-proven to significantly reduce the likelihood of a discharge described in §112.1(b)?	☐ Yes ☐ No ☐ NA
	Amendments implemented within six months of any Plan amendment?	☐ Yes ☐ No ☐ NA
	Five year Plan review and evaluation documented?	☐ Yes ☐ No ☐ NA
112.5(c)	Professional Engineer certification of any technical Plan amendments in accordance with all applicable requirements of §112.3(d) *[Except for self-certified Plans]*	☐ Yes ☐ No ☐ NA

Name:	License No.:	State:	Date of certification:

Reason for amendment:

Comments:

GENERAL SPCC REQUIREMENTS—40 CFR 112.7		PLAN	FIELD
Management approval at a level of authority to commit the necessary resources to fully implement the Plan[4]		☐ Yes ☐ No	
Plan follows sequence of the rule or is an equivalent Plan meeting all applicable rule requirements and includes a cross-reference of provisions		☐ Yes ☐ No ☐ NA	
If Plan calls for facilities, procedures, methods, or equipment not yet fully operational, details of their installation and start-up are discussed *(Note: Relevant for inspection evaluation and testing baselines.)*		☐ Yes ☐ No ☐ NA	
112.7(a)(2)	The Plan includes deviations from the requirements of §§112.7(g), (h)(2) and (3), and (i) and applicable subparts B and C of the rule, except the secondary containment requirements in §§112.7(c) and (h)(1), 112.9(c)(2), 112.9(d)(3), and 112.10(c)	☐ Yes ☐ No ☐ NA	
If **YES**	• The Plan states reasons for nonconformance	☐ Yes ☐ No ☐ NA	
	• Alternative measures described in detail and provide equivalent environmental protection *(Note: Inspector should document if the environmental equivalence is implemented in the field, in accordance with the Plan's description)*	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA

Describe each deviation and reasons for nonconformance:

[4] May be part of the Plan or demonstrated elsewhere.

		PLAN	FIELD
112.7(a)(3)	Plan describes physical layout of facility and includes a diagram[5] that identifies: • Location and contents of all regulated fixed oil storage containers • Storage areas where mobile or portable containers are located • Completely buried tanks otherwise exempt from the SPCC requirements (marked as "exempt") • Transfer stations • Connecting pipes, including intra-facility gathering lines that are otherwise exempt from the requirements of this part under §112.1(d)(11)	☐ Yes ☐ No	☐ Yes ☐ No
	Plan addresses each of the following:		
(i)	For each fixed container, type of oil and storage capacity (see Attachment A of this checklist). For mobile or portable containers, type of oil and storage capacity for each container or an estimate of the potential number of mobile or portable containers, the types of oil, and anticipated storage capacities	☐ Yes ☐ No	☐ Yes ☐ No
(ii)	Discharge prevention measures, including procedures for routine handling of products (loading, unloading, and facility transfers, etc.)	☐ Yes ☐ No	☐ Yes ☐ No
(iii)	Discharge or drainage controls, such as secondary containment around containers, and other structures, equipment, and procedures for the control of a discharge	☐ Yes ☐ No	☐ Yes ☐ No
(iv)	Countermeasures for discharge discovery, response, and cleanup (both facility's and contractor's resources)	☐ Yes ☐ No	☐ Yes ☐ No
(v)	Methods of disposal of recovered materials in accordance with applicable legal requirements	☐ Yes ☐ No	
(vi)	Contact list and phone numbers for the facility response coordinator, National Response Center, cleanup contractors with an agreement for response, and all Federal, State, and local agencies who must be contacted in the case of a discharge as described in §112.1(b)	☐ Yes ☐ No	
112.7(a)(4)	***Does not apply if the facility has submitted an FRP under §112.20:*** Plan includes information and procedures that enable a person reporting an oil discharge as described in §112.1(b) to relate information on the: • Exact address or location and phone number of the facility; • Date and time of the discharge; • Type of material discharged; • Estimates of the total quantity discharged; • Estimates of the quantity discharged as described in §112.1(b); • Source of the discharge; • Description of all affected media; • Cause of the discharge; • Damages or injuries caused by the discharge; • Actions being used to stop, remove, and mitigate the effects of the discharge; • Whether an evacuation may be needed; and • Names of individuals and/or organizations who have also been contacted	☐ Yes ☐ No ☐ NA	
112.7(a)(5)	***Does not apply if the facility has submitted a FRP under §112.20:*** Plan organized so that portions describing procedures to be used when a discharge occurs will be readily usable in an emergency	☐ Yes ☐ No ☐ NA	
112.7(b)	Plan includes a prediction of the direction, rate of flow, and total quantity of oil that could be discharged for each type of major equipment failure where experience indicates a reasonable potential for equipment failure	☐ Yes ☐ No ☐ NA	
Comments:			

[5] Note in comments any discrepancies between the facility diagram, the description of the physical layout of facility, and what is observed in the field

		PLAN	FIELD
112.7(c)	Appropriate containment and/or diversionary structures or equipment are provided to prevent a discharge as described in §112.1(b), **except as provided in §112.7(k) of this section for certain qualified operational equipment and §112.9(d)(3) for certain flowlines and intra-facility gathering lines at an oil production facility**. The entire containment system, including walls and floors, are capable of containing oil and are constructed to prevent escape of a discharge from the containment system before cleanup occurs. The method, design, and capacity for secondary containment address the typical failure mode and the most likely quantity of oil that would be discharged. See Attachment A of this checklist. **For offshore facilities**, one of the following or its equivalent: • Curbing or drip pans; • Sumps and collection systems; For onshore facilities, one of the following or its equivalent: • Dikes, berms, or retaining walls sufficiently impervious to contain oil; • Curbing or drip pans; • Sumps and collection systems; • Culverting, gutters or other drainage systems; • Weirs, booms or other barriers; • Spill diversion ponds; • Retention ponds; or • Sorbent materials.		
	Identify which of the following are present at the facility and if appropriate containment and/or diversionary structures or equipment are provided as described above:		
	☐ Bulk storage containers	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
	☐ Mobile/portable containers	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
	☐ Oil-filled operational equipment (as defined in 112.2)	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
	☐ Other oil-filled equipment (i.e., manufacturing equipment)	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
	☐ Piping and related appurtenances	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
	☐ Mobile refuelers or non-transportation-related tank cars	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
	☐ Transfer areas, equipment and activities	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
	☐ Identify any other equipment or activities that are not listed above: _____	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
112.7(d)	Secondary containment for one (or more) of the following provisions is determined to be impracticable: ☐ General secondary containment §112.7(c) ☐ Bulk storage containers §§112.8(c)(2)/112.12(c)(2) ☐ Loading/unloading rack §112.7(h)(1) ☐ Mobile/portable containers§§112.8(c)(11)/112.12(c)(11)	☐ Yes ☐ No	
If **YES**	• The impracticability of secondary containment is clearly demonstrated and described in the Plan	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
	• For bulk storage containers,[6] periodic integrity testing of containers and integrity and leak testing of the associated valves and piping is conducted	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
	(Does not apply if the facility has submitted a FRP under §112.20): • Contingency Plan following the provisions of 40 CFR part 109 is provided (see Attachment C of this checklist) **AND**	☐ Yes ☐ No ☐ NA	
	• Written commitment of manpower, equipment, and materials required to expeditiously control and remove any quantity of oil discharged that may be harmful	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA

Comments:

[6] These additional requirements apply only to bulk storage containers, when an impracticability determination has been made by the PE

		PLAN	FIELD
112.7(e)	Inspections and tests conducted in accordance with written procedures	☐ Yes ☐ No	☐ Yes ☐ No
	Record of inspections or tests signed by supervisor or inspector	☐ Yes ☐ No	☐ Yes ☐ No
	Kept with Plan for at least 3 years (see Attachment B of this checklist)[7]	☐ Yes ☐ No	☐ Yes ☐ No
112.7(f)	Personnel, training, and oil discharge prevention procedures		
(1)	Training of oil-handling personnel in operation and maintenance of equipment to prevent discharges; discharge procedure protocols; applicable pollution control laws, rules, and regulations; general facility operations; and contents of SPCC Plan	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
(2)	Person designated as accountable for discharge prevention at the facility and reports to facility management	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
(3)	Discharge prevention briefings conducted at least once a year for oil handling personnel to assure adequate understanding of the Plan. Briefings highlight and describe known discharges as described in §112.1(b) or failures, malfunctioning components, and any recently developed precautionary measures	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
112.7(h)	Tank car and tank truck loading/unloading rack[8] is present at the facility *Loading/unloading rack* means a fixed structure (such as a platform, gangway) necessary for loading or unloading a tank truck or tank car, which is located at a facility subject to the requirements of this part. A loading/unloading rack includes a loading or unloading arm, and may include any combination of the following: piping assemblages, valves, pumps, shut-off devices, overfill sensors, or personnel safety devices.		☐ Yes ☐ No
If **YES** (1)	Does loading/unloading rack drainage flow to catchment basin or treatment facility designed to handle discharges or use a quick drainage system?	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
	Containment system holds at least the maximum capacity of the largest single compartment of a tank car/truck loaded/unloaded at the facility	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
(2)	An interlocked warning light or physical barriers, warning signs, wheel chocks, or vehicle brake interlock system in the area adjacent to the **loading or unloading rack** to prevent vehicles from departing before complete disconnection of flexible or fixed oil transfer lines	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
(3)	Lower-most drains and all outlets on tank cars/trucks inspected prior to filling/departure, and, if necessary ensure that they are tightened, adjusted, or replaced to prevent liquid discharge while in transit	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
112.7(i)	Brittle fracture evaluation of field-constructed aboveground containers is conducted after tank repair, alteration, reconstruction, or change in service that might affect the risk of a discharge or after a discharge/failure due to brittle fracture or other catastrophe, and appropriate action taken as necessary (applies to only field-constructed aboveground containers in production service, drilling, and workover service)	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
112.7(j)	Discussion of conformance with applicable more stringent State rules, regulations, and guidelines and other effective discharge prevention and containment procedures listed in 40 CFR part 112	☐ Yes ☐ No ☐ NA	

Comments:

[7] Records of inspections and tests kept under usual and customary business practices will suffice

[8] Note that a tank car/truck loading/unloading rack must be present for §112.7(h) to apply. Though this requirement applies to all facilities, loading and unloading rack equipment is often not present at typical offshore production facilities.

		PLAN	FIELD
112.7(k)	Qualified oil-filled operational equipment is present at the facility[9] *Oil-filled operational equipment* means equipment that includes an oil storage container (or multiple containers) in which the oil is present solely to support the function of the apparatus or the device. Oil-filled operational equipment is not considered a bulk storage container, and does not include oil-filled manufacturing equipment (flow-through process). Examples of oil-filled operational equipment include, but are not limited to, hydraulic systems, lubricating systems (e.g. , those for pumps, compressors and other rotating equipment, including pumpjack lubrication systems), gear boxes, machining coolant systems, heat transfer systems, transformers, circuit breakers, electrical switches, and other systems containing oil solely to enable the operation of the device.	☐ Yes ☐ No	
If **YES**	Check which apply: Secondary Containment provided in accordance with 112.7(c) ☐ Alternative measure described below (confirm eligibility) ☐		
112.7(k)	Qualified Oil-Filled Operational Equipment • Has a single reportable discharge as described in §112.1(b) from any oil-filled operational equipment exceeding 1,000 U.S. gallons occurred within the three years prior to Plan certification date?	☐ Yes ☐ No ☐ NA	
	• Have two reportable discharges as described in §112.1(b) from any oil-filled operational equipment each exceeding 42 U.S. gallons occurred within any 12-month period within the three years prior to Plan certification date?[10]	☐ Yes ☐ No ☐ NA	
	If **YES** for either, secondary containment in accordance with §112.7(c) is required		
	• Facility procedure for inspections or monitoring program to detect equipment failure and/or a discharge is established and documented	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
	Does not apply if the facility has submitted a FRP under §112.20: • Contingency plan following 40 CFR part 109 (see Attachment C of this checklist) is provided in Plan **AND**	☐ Yes ☐ No ☐ NA	
	• Written commitment of manpower, equipment, and materials required to expeditiously control and remove any quantity of oil discharged that may be harmful is provided in Plan	☐ Yes ☐ No ☐ NA	
OFFSHORE OIL DRILLING, PRODUCTION OR WORKOVER FACILITIES—40 CFR 112.11		**PLAN**	**FIELD**
112.11(b)	Oil drainage collection equipment used to prevent and control small discharges around pumps, glands, valves, flanges, expansion joints, hoses, drain lines, separators, treaters, tanks, and associated equipment	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
	Facility drains are controlled and directed toward a central collection sump to prevent a discharge as described in §112.1(b); if drains and sumps not practicable, oil in collection equipment removed as often as necessary to prevent overflow	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
112.11(c)	For facilities using a sump system, sump and drains adequately sized	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
	For facilities using a sump system, spare pump available to remove liquids and assure that oil does not escape	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
	Regularly scheduled preventive maintenance inspection and testing program to assure reliable operation of liquid removal system and pump start-up device	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
	Redundant automatic sump pumps and control devices are installed if necessary	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
Comments:			

[9] This provision does not apply to oil-filled manufacturing equipment (flow-through process)

[10] A reportable discharge is a discharge as described in §112.1(b)(see 40 CFR part 110). Oil discharges that result from natural disasters, acts of war, or terrorism are not included in this determination. The gallon amount(s) specified (either 1,000 or 42) refers to the amount of oil that actually reaches navigable waters or adjoining shorelines not the total amount of oil spilled. The entire volume of the discharge is oil for this determination.

		PLAN	FIELD
112.11(d)	If separators and treaters are equipped with dump valves which predominantly fail in the closed position and where pollution risk is high, facility equipped to prevent discharges by: • Extending the flare line to a diked area if the separator is near shore; • Equipping separator with high liquid level sensor to automatically shut in wells producing to the separator; or • Installing parallel redundant dump valves.	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
112.11(e)	Atmospheric storage or surge containers equipped with high liquid level sensing devices that activate an alarm or control the flow, or otherwise prevent discharges	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
112.11(f)	Pressure containers equipped with high and low pressure sensing devices that activate an alarm or control the flow	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
112.11(g)	Containers equipped with suitable corrosion protection	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
112.11(h)	Written procedures maintained in the SPCC Plan for inspecting and testing pollution prevention equipment and systems	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
112.11(i)	Testing and inspection of pollution prevention equipment and systems conducted on a scheduled periodic basis commensurate with the complexity, conditions, and circumstances of the facility and any other applicable regulations.	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
	Simulated discharges are used for testing and inspecting human and equipment pollution control and countermeasure systems	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
112.11(j)	Detailed records are provided that describe surface and subsurface well shut-in valves and devices in use at the facility for each well.	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
	Records are sufficient to determine the method of activation or control, such as pressure differential, change in fluid or flow conditions, combination of pressure and flow, or manual or remote control mechanisms	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
112.11(k)	Blowout prevention (BOP) assembly and well control system installed before drilling below any casing string and during workover operations	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
	BOP assembly and well control system capable of controlling any well-head pressure that may be encountered while on the well	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
112.11(l)	Manifolds (headers) equipped with check valves on individual flowlines	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
112.11(m)	If the shut-in well pressure is greater than the working pressure of the flowline and manifold valves up to and including the header valves, flowlines are equipped with a high pressure sensing device and shut-in valve at the wellhead, **OR** pressure relief system provided for flowlines	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
112.11(n)	Piping appurtenant to the facility is protected from corrosion, such as with protective coatings or cathodic protection	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
112.11(o)	Sub-marine piping appurtenant to the facility is protected against environmental stresses and other activities such as fishing operations	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
112.11(p)	Sub-marine piping maintained in good operating condition at all times. Piping periodically inspected or tested on a regular schedule for failures. Documentation of inspections or tests kept at facility.	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
Comments:			

ATTACHMENT A ☐ NA **ONSHORE FACILITIES (EXCLUDING PRODUCTION) 40 CFR 112.8/112.12**		**PLAN**	**FIELD**
112.8(b)/ 112.12(b) Facility Drainage			
Diked Areas (1)	Drainage from diked storage areas is: • Restrained by valves, except where facility systems are designed to control such discharge, **OR** • Manually activated pumps or ejectors are used and the condition of the accumulation is inspected prior to draining dike to ensure no oil will be discharged	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
Comments:			
112.8(c)/112.12(c) Bulk Storage Containers ☐ NA *Bulk storage container* means any container used to store oil. These containers are used for purposes including, but not limited to, the storage of oil prior to use, while being used, or prior to further distribution in commerce. Oil-filled electrical, operating, or manufacturing equipment is not a bulk storage container. *If bulk storage containers are not present, mark this section Not Applicable (NA). If present, complete this section and Attachment C of this checklist.*			
(1)	Containers materials and construction are compatible with material stored and conditions of storage such as pressure and temperature	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
(3)	Is there drainage of uncontaminated rainwater from diked areas into a storm drain or open watercourse?	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
If **YES**	Bypass valve normally sealed closed	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
	• Retained rainwater is inspected to ensure that its presence will not cause a discharge as described in §112.1(b)	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
	• Bypass valve opened and resealed under responsible supervision	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
	• Adequate records of drainage are kept; for example, records required under permits issued in accordance with 40 CFR §§122.41(j)(2) and (m)(3)	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
(4)	For completely buried metallic tanks installed on or after January 10, 1974 (if not exempt from SPCC regulation because subject to all of the technical requirements of 40 CFR part 280 or 281):		
	• Provide corrosion protection with coatings or cathodic protection compatible with local soil conditions	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
	• Regular leak testing conducted	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
(5)	The buried section of partially buried or bunkered metallic tanks protected from corrosion with coatings or cathodic protection compatible with local soil conditions	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
Comments:			

ATTACHMENT A		PLAN	FIELD
(6)	Test or inspect each aboveground container for integrity on a regular schedule and whenever you make material repairs. Techniques include, but are not limited to: visual inspection, hydrostatic testing, radiographic testing, ultrasonic testing, acoustic emissions testing, or other system of non-destructive testing	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
	Appropriate qualifications for personnel performing tests and inspections are identified in the Plan and have been assessed in accordance with industry standards	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
	• The frequency and type of testing and inspections are documented, are in accordance with industry standards and take into account the container size, configuration and design	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
	• Comparison records of aboveground container integrity testing are maintained	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
	• Container supports and foundations regularly inspected	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
	• Outside of containers frequently inspected for signs of deterioration, discharges, or accumulation of oil inside diked areas	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
	• Records of all inspections and tests maintained[11]	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
Integrity Testing Standard identified in the Plan:			
112.12 (c)(6)(ii) *(Applies to AFVO Facilities only)*	Conduct formal visual inspection on a regular schedule for bulk storage containers that meet all of the following conditions: • Subject to 21 CFR part 110; • Elevated; • Constructed of austenitic stainless steel; • Have no external insulation; and • Shop-fabricated.	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
	In addition, you must frequently inspect the outside of the container for signs of deterioration, discharges, or accumulation of oil inside diked areas.	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
	You must determine and document in the Plan the appropriate qualifications for personnel performing tests and inspections.[11]	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
(10)	Visible discharges which result in a loss of oil from the container, including but not limited to seams, gaskets, piping, pumps, valves, rivets, and bolts are promptly corrected and oil in diked areas is promptly removed	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
112.8(d)/112.12(d)Facility transfer operations, pumping, and facility process			
(4)	Aboveground valves, piping, and appurtenances such as flange joints, expansion joints, valve glands and bodies, catch pans, pipeline supports, locking of valves, and metal surfaces are inspected regularly to assess their general condition	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
	Integrity and leak testing conducted on buried piping at time of installation, modification, construction, relocation, or replacement	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
Comments:			

[11] Records of inspections and tests kept under usual and customary business practices will suffice

ATTACHMENT B ☐ NA **ONSHORE OIL PRODUCTION FACILITIES—40 CFR 112.9**		**PLAN**	**FIELD**
(Drilling and workover facilities are excluded from the requirements of §112.9) *Production facility* means all structures (including but not limited to wells, platforms, or storage facilities), piping (including but not limited to flowlines or intra-facility gathering lines), or equipment (including but not limited to workover equipment, separation equipment, or auxiliary non-transportation-related equipment) used in the production, extraction, recovery, lifting, stabilization, separation or treating of oil (including condensate), or associated storage or measurement, and is located in an oil or gas field, at a facility. This definition governs whether such structures, piping, or equipment are subject to a specific section of this part.			
112.9(b) Oil Production Facility Drainage			
(1)	At tank batteries, separation and treating areas where there is a reasonable possibility of a discharge as described in §112.1(b), drains for dikes or equivalent measures are closed and sealed except when draining uncontaminated rainwater. Accumulated oil on the rainwater is removed and then returned to storage or disposed of in accordance with legally approved methods	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
	Prior to drainage, diked area inspected and action taken as provided below:		
	• 112.8(c)(3)(ii) - Retained rainwater is inspected to ensure that its presence will not cause a discharge as described in §112.1(b)	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
	• 112.8(c)(3)(iii) - Bypass valve opened and resealed under responsible supervision	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
	• 112.8(c)(3)(iv) - Adequate records of drainage are kept; for example, records required under permits issued in accordance with §122.41(j)(2) and (m)(3)	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
(2)	Field drainage systems (e.g., drainage ditches or road ditches) and oil traps, sumps, or skimmers inspected at regularly scheduled intervals for oil, and accumulations of oil promptly removed	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
112.9(c) Oil Production Facility Bulk Storage Containers *Bulk storage container* means any container used to store oil. These containers are used for purposes including, but not limited to, the storage of oil prior to use, while being used, or prior to further distribution in commerce. Oil-filled electrical, operating, or manufacturing equipment is not a bulk storage container.			
(1)	Containers materials and construction are compatible with material stored and conditions of storage such as pressure and temperature	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
(2)	Except as allowed for flow-through process vessels in §112.9(c)(5) and produced water containers in §112.9(c)(6), secondary containment provided for all tank battery, separation and treating facilities sized to hold the capacity of largest single container and sufficient freeboard for precipitation.	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
	Drainage from undiked area safely confined in a catchment basin or holding pond.	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
(3)	Except as allowed for flow-through process vessels in §112.9(c)(5) and produced water containers in §112.9(c)(6), periodically and upon a regular schedule, visually inspect containers for deterioration and maintenance needs, including foundation and supports of each container on or above the surface of the ground	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
(4)	New and old tank batteries engineered/updated in accordance with good engineering practices to prevent discharges including at least one of the following: • Adequate container capacity to prevent overfill if a pumper/gauger is delayed in making regularly scheduled rounds; • Overflow equalizing lines between containers so that a full container can overflow to an adjacent container; • Adequate vacuum protection to prevent container collapse; or • High level sensors to generate and transmit an alarm to the computer where the facility is subject to a computer production control system	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
Comments:			

ATTACHMENT B		PLAN	FIELD
(5)	**Flow-through Process Vessels.** Alternate requirements in lieu of sized secondary containment required in (c)(2) and requirements in (c)(3) above for facilities with flow-through process vessels:		
(i)	Flow-through process vessels and associated components (e.g. dump valves) are periodically and on a regular schedule visually inspected and/or tested for leaks, corrosion, or other conditions that could lead to a discharge as described in §112.1(b)	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
(ii)	Corrective actions or repairs have been made to flow-through process vessels and any associated components as indicated by regularly scheduled visual inspections, tests, or evidence of an oil discharge	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
(iii)	Oil removed or other actions initiated to promptly stabilize and remediate any accumulation of oil discharges associated with the produced water container	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
(iv)	All flow-through process vessels comply with §§112.9(c)(2) and (c)(3) within six months of any flow-through process vessel discharge of more than 1,000 U.S. gallons of oil in a single discharge as described in §112.1(b) or discharges of more than 42 U.S. gallons of oil in each of two discharges as described in §112.1(b) within any twelve month period.[12]	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
112.9(d) Facility transfer operations, pumping, and facility process			
(1)	All aboveground valves and piping associated with transfer operations are inspected periodically and upon a regular schedule to determine their general condition. Include the general condition of flange joints, valve glands and bodies, drip pans, pipe supports, pumping well polish rod stuffing boxes, bleeder and gauge valves, and other such items	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
(3)	If flowlines and intra-facility gathering lines are not provided with secondary containment in accordance with §112.7(c) and the facility is not required to submit an FRP under §112.20, then the SPCC Plan includes:		
(i)	• An oil spill contingency plan following the provisions of 40 CFR part 109[13]	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
(ii)	• A written commitment of manpower, equipment, and materials required to expeditiously control and remove any quantity of oil discharged that might be harmful	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
Comments:			

[12] Oil discharges that result from natural disasters, acts of war, or terrorism are not included in this determination. The gallon amount(s) specified (either 1,000 or 42) refers to the amount of oil that actually reaches navigable waters or adjoining shorelines not the total amount of oil spilled. The entire volume of the discharge is oil for this determination.

[13] Note that the implementation of a 40 CFR part 109 plan does not require a PE impracticability determination for this specific requirement

ATTACHMENT B		PLAN	FIELD
(4)	A flowline/intra-facility gathering line maintenance program to prevent discharges is prepared and implemented and includes the following procedures:		
(i)	Flowlines and intra-facility gathering lines and associated valves and equipment are compatible with the type of production fluids, their potential corrosivity, volume, and pressure, and other conditions expected in the operational environment	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
(ii)	Flowlines and intra-facility gathering lines and associated appurtenances are visually inspected and/or tested on a periodic and regular schedule for leaks, oil discharges, corrosion, or other conditions that could lead to a discharge as described in §112.1(b).	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
	If flowlines and intra-facility gathering lines are not provided with secondary containment in accordance with §112.7(c), the frequency and type of testing allows for the implementation of a contingency plan as described under 40 CFR 109 or an FRP submitted under §112.20	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
(iii)	Repairs or other corrective actions are made to any flowlines and intra-facility gathering lines and associated appurtenances as indicated by regularly scheduled visual inspections, tests, or evidence of a discharge	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
(iv)	Oil removed or other actions initiated to promptly stabilize and remediate any accumulation of oil discharges associated with the produced water containers	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
ATTACHMENT B ☐ NA **ONSHORE OIL DRILLING AND WORKOVER FACILITIES—40 CFR 112.10**		**PLAN**	**FIELD**
112.10(b)	Mobile drilling or workover equipment is positioned or located to prevent a discharge as described in §112.1(b)	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
112.10(c)	Catchment basins or diversion structures are provided to intercept and contain discharges of fuel, crude oil, or oily drilling fluids	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
112.10(d)	Blowout prevention (BOP) assembly and well control system installed before drilling below any casing string or during workover operations	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
	BOP assembly and well control system is capable of controlling any well-head pressure that may be encountered while on the well	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA

Comments:

This page left intentionally blank.

ATTACHMENT C: SPCC FIELD INSPECTION AND PLAN REVIEW TABLE

Documentation of Field Observations for Containers and Associated Requirements

Inspectors should use this table to document observations of containers as needed.

Containers and Piping

Check containers for leaks, specifically looking for: drip marks, discoloration of tanks, puddles containing spilled or leaked material, corrosion, cracks, and localized dead vegetation, and standards/specifications of construction.

Check aboveground container foundation for: cracks, discoloration, and puddles containing spilled or leaked material, settling, gaps between container and foundation, and damage caused by vegetation roots.

Check all piping for: droplets of stored material, discoloration, corrosion, bowing of pipe between supports, evidence of stored material seepage from valves or seals, evidence of leaks, and localized dead vegetation. For all aboveground piping, include the general condition of flange joints, valve glands and bodies, drip pans, pipe supports, bleeder and gauge valves, and other such items (Document in comments section of §112.11.)

Secondary Containment (Active and Passive)

Check secondary containment for: containment system (including walls and floor) ability to contain oil such that oil will not escape the containment system before cleanup occurs, proper sizing, cracks, discoloration, presence of spilled or leaked material (standing liquid), erosion, corrosion, penetrations in the containment system, and valve conditions.

Check dike or berm systems for: level of precipitation in dike/available capacity, operational status of drainage valves (closed), dike or berm impermeability, debris, erosion, impermeability of the earthen floor/walls of diked area, and location/status of pipes, inlets, drainage around and beneath containers, presence of oil discharges within diked areas.

Check drainage systems for: an accumulation of oil that may have resulted from any small discharge, including field drainage systems (such as drainage ditches or road ditches), and oil traps, sumps, or skimmers. Ensure any accumulations of oil have been promptly removed.

Check retention and drainage ponds for: erosion, available capacity, presence of spilled or leaked material, debris, and stressed vegetation.

Check active measures (countermeasures) for: amount indicated in plan is available and appropriate; deployment procedures are realistic; material is located so that they are readily available; efficacy of discharge detection; availability of personnel and training, appropriateness of measures to prevent a discharge as described in §112.1(b). *Note that appropriate evaluation and consideration must be given to any use of active measures at an unmanned production facility.*

Container ID/ General Condition[14] Aboveground or Buried Tank	Storage Capacity and Type of Oil	Type of Containment/ Drainage Control	Overfill Protection and Testing & Inspections

[14] Identify each tank with either an A to indicate aboveground or B for completely buried

ATTACHMENT C: SPCC FIELD INSPECTION AND PLAN REVIEW TABLE (CONT.)

Documentation of Field Observations for Containers and Associated Requirements

Container ID/ General Condition[15] Aboveground or Buried Tank	Storage Capacity and Type of Oil	Type of Containment/ Drainage Control	Overfill Protection and Testing & Inspections

[15] Identify each tank with either an A to indicate aboveground or B for completely buried

ATTACHMENT D: SPCC INSPECTION AND TESTING CHECKLIST

Required Documentation of Tests and Inspections

Records of inspections and tests required by 40 CFR part 112 signed by the appropriate supervisor or inspector must be kept by all facilities with the SPCC Plan for a period of three years. Records of inspections and tests conducted under usual and customary business practices will suffice. Documentation of the following inspections and tests should be kept with the SPCC Plan.

	Inspection or Test	Documentation		Not Applicable
		Present	Not Present	
112.7–General SPCC Requirements				
(d)	Integrity testing for bulk storage containers with no secondary containment system and for which an impracticability determination has been made	☐	☐	☐
(d)	Integrity and leak testing of valves and piping associated with bulk storage containers with no secondary containment system and for which an impracticability determination has been made	☐	☐	☐
(h)(3)	Inspection of lowermost drain and all outlets of tank car or tank truck prior to filling and departure from loading/unloading rack	☐	☐	☐
(i)	Evaluation of field-constructed aboveground containers for potential for brittle fracture or other catastrophic failure when the container undergoes a repair, alteration, reconstruction or change in service or has discharged oil or failed due to brittle fracture failure or other catastrophe	☐	☐	☐
k(2)(i)	Inspection or monitoring of qualified oil-filled operational equipment when the equipment meets the qualification criteria in §112.7(k)(1) and facility owner/operator chooses to implement the alternative requirements in §112.7(k)(2) that include an inspection or monitoring program to detect oil-filled operational equipment failure and discharges	☐	☐	☐
112.11–Offshore oil drilling, production and workover facilities				
(c)	Regularly scheduled preventive maintenance inspection and testing program to assure reliable operation of liquid removal system and pump start-up device	☐	☐	☐
(i)	Testing and inspection of pollution prevention equipment and systems performed on a scheduled periodic basis. Simulated discharges are used for testing and inspecting human and equipment pollution control and countermeasure systems	☐	☐	☐
(p)	Submarine piping periodically inspected or tested for failures	☐	☐	☐
112.8/112.12–Onshore Facilities (excluding oil production facilities)				☐ NA
(b)(1), (b)(2)	Inspection of storm water released from diked areas into facility drainage directly to a watercourse	☐	☐	☐
(c)(3)	Inspection of rainwater released directly from diked containment areas to a storm drain or open watercourse before release, open and release bypass valve under supervision, and records of drainage events	☐	☐	☐
(c)(4)	Regular leak testing of completely buried metallic storage tanks installed on or after January 10, 1974 and regulated under 40 CFR 112	☐	☐	☐
(c)(6)	Regular integrity testing of aboveground containers and integrity testing after material repairs, including comparison records	☐	☐	☐
(c)(6), (c)(10)	Regular visual inspections of the outsides of aboveground containers, supports and foundations	☐	☐	☐
(c)(6)	Frequent inspections of diked areas for accumulations of oil	☐	☐	☐
(d)(4)	Regular inspections of aboveground valves, piping and appurtenances and assessments of the general condition of flange joints, expansion joints, valve glands and bodies, catch pans, pipeline supports, locking of valves, and metal surfaces	☐	☐	☐
(d)(4)	Integrity and leak testing of buried piping at time of installation, modification, construction, relocation or replacement	☐	☐	☐

112.9–Onshore Oil Production Facilities (excluding drilling and workover facilities)				☐ NA
(b)(1)	Rainwater released directly from diked containment areas inspected following §§112.8(c)(3)(ii), (iii) and (iv), including records of drainage kept	☐	☐	☐
(b)(2)	Field drainage systems, oil traps, sumps, and skimmers inspected regularly for oil, and accumulations of oil promptly removed	☐	☐	☐
(c)(3)	Containers, foundations and supports inspected visually for deterioration and maintenance needs	☐	☐	☐
(c)(5)(i)	In lieu of having sized secondary containment, flow-through process vessels and associated components visually inspected and/or tested periodically and on a regular schedule for conditions that could result in a discharge as described in §112.1(b)	☐	☐	☐
(d)(1)	All aboveground valves and piping associated with transfers are regularly inspected	☐	☐	☐
(d)(4)(ii)	For flowlines and intra-facility gathering lines without secondary containment, in accordance with §112.7(c), lines are visually inspected and/or tested periodically and on a regular schedule to allow implementing the part 109 contingency plan or the FRP submitted under §112.20	☐	☐	☐

Comments:

ATTACHMENT E: SPCC CONTINGENCY PLAN REVIEW CHECKLIST

☐ NA

40 CFR Part 109–Criteria for State, Local and Regional Oil Removal Contingency Plans

If SPCC Plan includes an impracticability determination for secondary containment in accordance with §112.7(d), the facility owner/operator is required to provide an oil spill contingency plan following 40 CFR part 109, unless he or she has submitted a FRP under §112.20. An oil spill contingency plan may also be developed, unless the facility owner/operator has submitted a FRP under §112.20 as one of the required alternatives to general secondary containment for qualified oil filled operational equipment in accordance with §112.7(k).

	109.5–Development and implementation criteria for State, local and regional oil removal contingency plans[16]	Yes	No
(a)	Definition of the authorities, responsibilities and duties of all persons, organizations or agencies which are to be involved in planning or directing oil removal operations.	☐	☐
(b)	Establishment of notification procedures for the purpose of early detection and timely notification of an oil discharge including:	☐	☐
(1)	The identification of critical water use areas to facilitate the reporting of and response to oil discharges.	☐	☐
(2)	A current list of names, telephone numbers and addresses of the responsible persons (with alternates) and organizations to be notified when an oil discharge is discovered.	☐	☐
(3)	Provisions for access to a reliable communications system for timely notification of an oil discharge, and the capability of interconnection with the communications systems established under related oil removal contingency plans, particularly State and National plans (e.g., National Contingency Plan (NCP)).	☐	☐
(4)	An established, prearranged procedure for requesting assistance during a major disaster or when the situation exceeds the response capability of the State, local or regional authority.	☐	☐
(c)	Provisions to assure that full resource capability is known and can be committed during an oil discharge situation including:	☐	☐
(1)	The identification and inventory of applicable equipment, materials and supplies which are available locally and regionally.	☐	☐
(2)	An estimate of the equipment, materials and supplies that would be required to remove the maximum oil discharge to be anticipated.	☐	☐
(3)	Development of agreements and arrangements in advance of an oil discharge for the acquisition of equipment, materials and supplies to be used in responding to such a discharge.	☐	☐
(d)	Provisions for well-defined and specific actions to be taken after discovery and notification of an oil discharge including:	☐	☐
(1)	Specification of an oil discharge response operating team consisting of trained, prepared and available operating personnel.	☐	☐
(2)	Pre-designation of a properly qualified oil discharge response coordinator who is charged with the responsibility and delegated commensurate authority for directing and coordinating response operations and who knows how to request assistance from Federal authorities operating under existing national and regional contingency plans.	☐	☐
(3)	A preplanned location for an oil discharge response operations center and a reliable communications system for directing the coordinated overall response operations.	☐	☐
(4)	Provisions for varying degrees of response effort depending on the severity of the oil discharge.	☐	☐
(5)	Specification of the order of priority in which the various water uses are to be protected where more than one water use may be adversely affected as a result of an oil discharge and where response operations may not be adequate to protect all uses.	☐	☐
(e)	Specific and well defined procedures to facilitate recovery of damages and enforcement measures as provided for by State and local statutes and ordinances.	☐	☐

[16] The contingency plan should be consistent with all applicable state and local plans, Area Contingency Plans, and the NCP.

This page left intentionally blank.

ATTACHMENT F: ADDITIONAL COMMENTS

ATTACHMENT F: ADDITIONAL COMMENTS (CONT.)

ATTACHMENT G: PHOTO DOCUMENTATION NOTES

Photo#	Photographer Name	Time of Photo Taken	Compass Direction	Description

ATTACHMENT G: PHOTO DOCUMENTATION NOTES (CONT.)

Photo#	Photographer Name	Time of Photo Taken	Compass Direction	Description

U.S. ENVIRONMENTAL PROTECTION AGENCY
SPCC FIELD INSPECTION AND PLAN REVIEW CHECKLIST

TIER I QUALIFIED FACILITIES

Overview of the Checklist

This checklist is designed to assist EPA inspectors in conducting a thorough and nationally consistent inspection of a facility's compliance with the Spill Prevention, Control, and Countermeasure (SPCC) rule at 40 CFR part 112. It is a required tool to help federal inspectors (or their contractors) record observations for the site inspection and review of the SPCC Plan. While the checklist is meant to be comprehensive, the inspector should always refer to the SPCC rule in its entirety, the SPCC Regional Inspector Guidance Document, and other relevant guidance for evaluating compliance. This checklist must be completed in order for an inspection to count toward an agency measure (i.e., OEM inspection measures or GPRA). The completed checklist and supporting documentation (i.e. photo logs or additional notes) serve as the inspection report.

This checklist addresses requirements for Tier I Qualified Facilities that meet the eligibility criteria set forth in §112.3(g)(1).

Separate and standalone checklists address the requirements for:
Onshore facilities including Tier II Qualified Facilities (excluding oil drilling, production and workover facilities);
Onshore oil drilling, production and workover facilities including Tier II Qualified Facilities as defined in §112.3(g)(2); and
Offshore drilling, production and workover facilities

Tier I Qualified Facilities must meet the rule requirements in §112.6 and other applicable sections specified in §112.6. The checklist is organized according to the SPCC rule. Each item in the checklist identifies the relevant section and paragraph in 40 CFR part 112 where that requirement is stated.

- Sections 112.1 through 112.5 specify the applicability of the rule and requirements for the preparation, implementation, and amendment of SPCC Plans. For these sections, the checklist includes data fields to be completed, as well as several questions with "yes," "no" or "NA" answers.
- Section 112.6 includes requirements for Tier I qualified facilities.
- Section 112.7 includes general requirements that apply to all facilities (unless otherwise excluded).

<u>Attachments</u>

- Attachment A is a checklist for Sections 112.8 and 112.12. This checklist specifies requirements for spill prevention, control, and countermeasures for onshore facilities (excluding oil production facilities).
- Attachment B is a checklist that specifies requirements for spill prevention, control, and countermeasures for onshore oil production facilities (112.9 provisions) and onshore drilling and workover facilities (112.10 provisions)
- Attachment C is for recording information about containers and other locations at the facility that require secondary containment.
- Attachment D is a checklist for documenting the tests and inspections the facility operator is required to keep with the SPCC Plan.
- Attachment E is a checklist for oil spill contingency plans following 40 CFR 109. Unless a facility has submitted a Facility Response Plan (FRP) under 40 CFR 112.20, a contingency plan following 40 CFR 109 is required if a facility the owner or operator of a facility with qualified oil-filled operational equipment chooses to implement alternative requirements instead of general secondary containment requirements as provided in 40 CFR 112.7(k).
- Attachment F is for recording additional comments or notes.
- Attachment G is for recording information about photos.

The inspector needs to evaluate whether the requirements in the checklist are addressed adequately or inadequately in the SPCC Plan and whether it is implemented adequately in the field (either by field observation or record review). For the SPCC Plan and implementation in the field, if a requirement is addressed adequately, mark the "Yes" box in the appropriate column. If a requirement is not addressed adequately, mark the "No" box. If a requirement does not apply to the particular facility or the question asked is not appropriate for the facility, mark as "NA". Discrepancies or descriptions of inspector interpretation of "No" vs. "NA" may be documented in the comments box subsequent to each section. If a provision of the rule applies only to the SPCC Plan, the "Field" column is shaded.

Space is provided throughout the checklist to record comments. Additional space is available as Attachment F at the end of the checklist. Comments should remain factual and support the evaluation of compliance.

FACILITY INFORMATION			
FACILITY NAME:			
LATITUDE:	LONGITUDE:	GPS DATUM:	
Section/Township/Range:	FRS#/OIL DATABASE ID:	ICIS#:	
ADDRESS:			
CITY:	STATE:	ZIP:	COUNTY:
MAILING ADDRESS (IF DIFFERENT FROM FACILITY ADDRESS – IF NOT, PRINT "SAME"):			
CITY:	STATE:	ZIP:	COUNTY:
TELEPHONE:	FACILITY CONTACT NAME/TITLE:		
OWNER NAME:			
OWNER ADDRESS:			
CITY:	STATE:	ZIP:	COUNTY:
TELEPHONE:	FAX:	EMAIL:	
FACILITY OPERATOR NAME (IF DIFFERENT FROM OWNER – IF NOT, PRINT "SAME"):			
OPERATOR ADDRESS:			
CITY:	STATE:	ZIP:	COUNTY:
TELEPHONE:	OPERATOR CONTACT NAME/TITLE:		
FACILITY TYPE:			NAICS CODE:
HOURS PER DAY FACILITY ATTENDED:		TOTAL FACILITY CAPACITY:	
TYPE(S) OF OIL STORED:			
LOCATED IN INDIAN COUNTRY? ☐ YES ☐ NO RESERVATION NAME:			

INSPECTION/PLAN REVIEW INFORMATION		
PLAN REVIEW DATE:	REVIEWER NAME:	
INSPECTION DATE:	TIME:	ACTIVITY ID NO:
LEAD INSPECTOR:		
OTHER INSPECTOR(S):		

INSPECTION ACKNOWLEDGMENT	
I performed an SPCC inspection at the facility specified above.	
INSPECTOR SIGNATURE:	DATE:
SUPERVISOR REVIEW/SIGNATURE:	DATE:

SPCC GENERAL APPLICABILITY—40 CFR 112.1

IS THE FACILITY REGULATED UNDER 40 CFR part 112?

The completely buried oil storage capacity is over 42,000 U.S. gallons, **OR** the aggregate aboveground oil storage capacity is over 1,320 U.S. gallons **AND**	☐ Yes ☐ No
The facility is a non-transportation-related facility engaged in drilling, producing, gathering, storing, processing, refining, transferring, distributing, using, or consuming oil and oil products, which due to its location could reasonably be expected to discharge oil into or upon the navigable waters of the United States	☐ Yes ☐ No

AFFECTED WATERWAY(S):	DISTANCE:

FLOW PATH TO WATERWAY:

Note: The following storage capacity is not considered in determining applicability of SPCC requirements:

- *Equipment subject to the authority of the U.S. Department of Transportation, U.S. Department of the Interior, or Minerals Management Service, as defined in Memoranda of Understanding dated November 24, 1971, and November 8, 1993; Tank trucks that return to an otherwise regulated facility that contain only residual amounts of oil (EPA Policy letter)*
- *Completely buried tanks subject to all the technical requirements of 40 CFR part 280 or a state program approved under 40 CFR part 281;*
- *Underground oil storage tanks deferred under 40 CFR part 280 that supply emergency diesel generators at a nuclear power generation facility licensed by the Nuclear Regulatory Commission (NRC) and subject to any NRC provision regarding design and quality criteria, including but not limited to CFR part 50;*
- *Any facility or part thereof used exclusively for wastewater treatment (production, recovery or recycling of oil is not considered wastewater treatment); (This does not include other oil containers located at a wastewater treatment facility, such as generator tanks or transformers)*
- *Containers smaller than 55 U.S. gallons;*
- *Permanently closed containers (as defined in §112.2);*
- *Motive power containers (as defined in §112.2);*
- *Hot-mix asphalt or any hot-mix asphalt containers;*
- *Heating oil containers used solely at a single-family residence;*
- *Pesticide application equipment and related mix containers;*
- *Any milk and milk product container and associated piping and appurtenances; and*
- *Intra-facility gathering lines subject to the regulatory requirements of 49 CFR part 192 or 195.*

Does the facility have an SPCC Plan? ☐ Yes ☐ No

SPCC TIER I QUALIFIED FACILITY APPLICABILITY—40 CFR 112.3(g)(1),(2)

The aggregate aboveground oil storage capacity is 10,000 U.S. gallons or less **AND**	☐ Yes ☐ No
The capacity of each individual aboveground oil storage container is 5,000 U.S. gallons or less **AND**	☐ Yes ☐ No
In the three years prior to the SPCC Plan self-certification date, or since becoming subject to the rule (if the facility has been in operation for less than three years), the facility has **NOT** had:	
• A single discharge as described in §112.1(b) exceeding 1,000 U.S. gallons, **OR**	☐ Yes ☐ No
• Two discharges as described in §112.1(b) each exceeding 42 U.S. gallons within any twelve-month period[1]	☐ Yes ☐ No

IF ***YES*** TO ALL OF THE ABOVE, THEN THE FACILITY IS CONSIDERED A TIER I QUALIFIED FACILITY.[2]

Comments:

[1] Oil discharges that result from natural disasters, acts of war, or terrorism are not included in this determination. The gallon amount(s) specified (either 1,000 or 42) refers to the amount of oil that actually reaches navigable waters or adjoining shorelines not the total amount of oil spilled. The entire volume of the discharge is oil for this determination.

[2] An owner/operator who self-certifies a Tier I SPCC Plan may not include any environmentally equivalent alternatives or secondary containment impracticability determinations in the SPCC Plan.

REQUIREMENTS FOR PREPARATION AND IMPLEMENTATION OF A SPCC PLAN—40 CFR 112.3

Date facility began operations:

Date of initial SPCC Plan preparation:	Current Plan version (date/number):

112.3(a)	**For facilities (except farms), including mobile or portable facilities:** • In operation on or prior to November 10, 2011: Plan prepared and/or amended and fully implemented by **November 10, 2011** • Facilities beginning operation after November 10, 2011: o *Oil production facilities* - Plan prepared and fully implemented within six months after beginning operations; or o *All other facilities* - Plan prepared and fully implemented before operations begin	☐ Yes ☐ No ☐ NA ☐ Yes ☐ No ☐ NA ☐ Yes ☐ No ☐ NA
	For farms (as defined in §112.2): • In operation on or prior to August 16, 2002: Plan maintained, amended and implemented by **May 10, 2013** • Beginning operations after August 16, 2002 through May 10, 2013: Plan prepared and fully implemented by **May 10, 2013** • Beginning operations after May 10, 2013: Plan prepared and fully implemented before beginning operations	☐ Yes ☐ No ☐ NA ☐ Yes ☐ No ☐ NA ☐ Yes ☐ No ☐ NA
112.3(e)(1)	Plan is available onsite if attended at least 4 hours per day. If facility is unattended, Plan is available at the nearest field office. *(Please note nearest field office contact information in comments section below.)*	☐ Yes ☐ No ☐ NA

Comments:

AMENDMENT OF SPCC PLAN BY REGIONAL ADMINISTRATOR (RA)—40 CFR 112.4

112.4(a),(c)	Has the facility discharged more than 1,000 U.S. gallons of oil in a single reportable discharge or more than 42 U.S. gallons in each of two reportable discharges in any 12-month period?[3]	☐ Yes ☐ No
If **YES**	• Was information submitted to the RA as required in §112.4(a)?[4] • Was information submitted to the appropriate agency or agencies in charge of oil pollution control activities in the State in which the facility is located§112.4(c) • Date(s) and volume(s) of reportable discharges(s) under this section: _____ • Were the discharges reported to the NRC[5]?	☐ Yes ☐ No ☐ NA ☐ Yes ☐ No ☐ NA ☐ Yes ☐ No
112.4(d),(e)	Have changes required by the RA been implemented in the Plan and/or facility?	☐ Yes ☐ No ☐ NA

Comments:

[3] A reportable discharge is a discharge as described in §112.1(b)(see 40 CFR part 110). The gallon amount(s) specified (either 1,000 or 42) refers to the amount of oil that actually reaches navigable waters or adjoining shorelines not the total amount of oil spilled. The entire volume of the discharge is oil for this determination

[4] Triggering this threshold may disqualify the facility from meeting the Qualified Facility criteria if it occurred in the three years prior to self-certification

[5] Inspector Note: Confirm any spills identified above were reported to NRC

AMENDMENT OF SPCC PLAN BY THE OWNER OR OPERATOR—40 CFR 112.5		
112.5(a)	Has there been a change at the facility that materially affects the potential for a discharge described in §112.1(b)?	☐ Yes ☐ No
If **YES**	• Was the Plan amended within six months of the change?	☐ Yes ☐ No
	• Were amendments implemented within six months of any Plan amendment?	☐ Yes ☐ No
112.5(b)	Review and evaluation of the Plan completed at least once every 5 years?	☐ Yes ☐ No ☐ NA
	Following Plan review, was Plan amended within six months to include more effective prevention and control technology that has been field-proven to significantly reduce the likelihood of a discharge described in §112.1(b)?	☐ Yes ☐ No ☐ NA
	Amendments implemented within six months of any Plan amendment?	☐ Yes ☐ No ☐ NA
	Five year Plan review and evaluation documented?	☐ Yes ☐ No ☐ NA
112.5(c)	Professional Engineer certification of any technical Plan amendments in accordance with all applicable requirements of §112.3(d) *[Except for self-certified Plans]*	☐ Yes ☐ No ☐ NA

Name:	License No.:	State:	Date of certification:

Reason for amendment:

TIER I QUALIFIED FACILITY PLAN REQUIREMENTS —40 CFR 112.6(a)		
112.6(a)(1)	**Plan Certification:** Plan prepared to comply with the requirements of §112.6(a)(3) using the Appendix G template	☐ Yes ☐ No ☐ NA
(i)	He or she is familiar with the requirements of 40 CFR part 112	☐ Yes ☐ No ☐ NA
(ii)	He or she has visited and examined the facility[6]	☐ Yes ☐ No ☐ NA
(iii)	The Plan has been prepared in accordance with accepted and sound industry practices and standards	☐ Yes ☐ No ☐ NA
(iv)	Procedures for required inspections and testing have been established	☐ Yes ☐ No ☐ NA
(v)	He or she will fully implement the Plan	☐ Yes ☐ No ☐ NA
(vi)	The facility meets the qualification criteria in §112.3(g)(1)	☐ Yes ☐ No ☐ NA
(vii)	The Plan does not deviate from any requirements as allowed by §§112.7(a)(2) and 112.7(d), or include measures pursuant to §112.9(c)(6) for produced water containers and any associated piping	☐ Yes ☐ No ☐ NA
(viii)	The Plan and individual(s) responsible for implementing the Plan have the full approval of management and the facility owner or operator has committed the necessary resources to fully implement the Plan.	☐ Yes ☐ No ☐ NA
112.6(a)(2)	**Technical Amendments:** The owner/operator self-certified the Plan's technical amendments for a change in facility design, construction, operation, or maintenance that affected potential for a §112.1(b) discharge	☐ Yes ☐ No ☐ NA
If **YES**	• Certification of technical amendments is in accordance with the self-certification provisions of §112.6(a)(1).	☐ Yes ☐ No ☐ NA
	An individual oil storage container capacity exceeds 5,000 U.S. gallons or the aggregate aboveground oil storage capacity increased to more than 10,000 U.S. gallons as a result of the change	☐ Yes ☐ No ☐ NA
If **YES**	*The facility no longer meets the Tier I qualifying criteria in §112.3(g)(1) because an individual oil storage container capacity exceeds 5,000 U.S. gallons or the facility aboveground storage capacity exceeds 10,000 U.S. gallons*	
	The following has been or will be completed within six months following the amendment:	
(i)	• Plan prepared and implemented in accordance with the requirements for a Tier II Qualified Facility (§112.6(b)) if the facility meets the eligibility criteria **OR**	☐ Yes ☐ No ☐ NA
(ii)	• Plan prepared and implemented in accordance with the general Plan requirements in §112.7 and applicable requirements in subparts B and C and certified by a PE as required under §112.3(d)	☐ Yes ☐ No ☐ NA

[6] Note that only the person certifying the Plan can make the site visit

112.6(a)(3)(i)	Plan includes a prediction of the direction and total quantity of oil which could be discharged from the facility as a result of each type of major equipment failure if there is a reasonable potential for equipment failure (such as loading or unloading equipment, tank overflow, rupture, or leakage, or any other equipment known to be a source of discharge)	☐ Yes ☐ No ☐ NA
(ii)	Bulk storage container installations (except mobile refuelers and other non-transportation-related tank trucks), including mobile or portable oil storage containers, are constructed to provide secondary containment for the entire capacity of the largest single container plus additional capacity to contain precipitation, and	☐ Yes ☐ No ☐ NA
	Mobile or portable oil storage containers positioned or located to prevent a §112.1(b) discharge	☐ Yes ☐ No ☐ NA
(iii)	Plan describes a system or documented procedure to prevent overfills for each container and is regularly tested to ensure proper operation or efficacy	☐ Yes ☐ No ☐ NA
Comments:		

GENERAL SPCC REQUIREMENTS—40 CFR 112.7		**PLAN**	**FIELD**
Management approval at a level of authority to commit the necessary resources to fully implement the Plan[7]		☐ Yes ☐ No	
Plan follows sequence of the rule or is an equivalent Plan meeting all applicable rule requirements and includes a cross-reference of provisions		☐ Yes ☐ No ☐ NA	
If Plan calls for facilities, procedures, methods, or equipment not yet fully operational, details of their installation and start-up are discussed *(Note: Relevant for inspection evaluation and testing baselines.)*		☐ Yes ☐ No ☐ NA	
112.7(a)(3)	Plan addresses each of the following:		
(i)	For each fixed container, type of oil and storage capacity (see Attachment C of this checklist). For mobile or portable containers, type of oil and storage capacity for each container or an estimate of the potential number of mobile or portable containers, the types of oil, and anticipated storage capacities	☐ Yes ☐ No	☐ Yes ☐ No
(iv)	Countermeasures for discharge discovery, response, and cleanup (both facility's and contractor's resources)	☐ Yes ☐ No	☐ Yes ☐ No
(vi)	Contact list and phone numbers for the facility response coordinator, National Response Center, cleanup contractors with an agreement for response, and all Federal, State, and local agencies who must be contacted in the case of a discharge as described in §112.1(b)	☐ Yes ☐ No	
112.7(a)(4)	Plan includes information and procedures that enable a person reporting an oil discharge as described in §112.1(b) to relate information on the: • Exact address or location and phone number of the facility; • Date and time of the discharge; • Type of material discharged; • Estimates of the total quantity discharged; • Estimates of the quantity discharged as described in §112.1(b); • Source of the discharge; • A description of all affected media; • Cause of the discharge; • Damages or injuries caused by the discharge; • Actions being used to stop, remove, and mitigate the effects of the discharge; • Whether an evacuation may be needed; • Names of individuals and/or organizations who have also been contacted	☐ Yes ☐ No ☐ NA	
112.7(a)(5)	Plan organized so that portions describing procedures to be used when a discharge occurs will be readily usable in an emergency	☐ Yes ☐ No ☐ NA	
Comments:			

[7] May be part of the Plan or demonstrated elsewhere.

		PLAN	FIELD
112.7(c)	Appropriate containment and/or diversionary structures or equipment are provided to prevent a discharge as described in §112.1(b), **except as provided in §112.7(k) of this section for certain qualified operational equipment and §112.9(d)(3) for certain flowlines and intra-facility gathering lines at an oil production facility**. The entire containment system, including walls and floors, are capable of containing oil and are constructed to prevent escape of a discharge from the containment system before cleanup occurs. The method, design, and capacity for secondary containment address the typical failure mode and the most likely quantity of oil that would be discharged. See Attachment C of this checklist. **For onshore facilities**, one of the following or its equivalent: • Dikes, berms, or retaining walls sufficiently impervious to contain oil, • Curbing or drip pans, • Sumps and collection systems, • Culverting, gutters or other drainage systems, • Weirs, booms or other barriers, • Spill diversion ponds, • Retention ponds, or • Sorbent materials		
	Identify which of the following are present at the facility and if appropriate containment and/or diversionary structures or equipment are provided as described above:		
	☐ Bulk storage containers	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
	☐ Mobile/portable containers	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
	☐ Oil-filled operational equipment (as defined in 112.2)	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
	☐ Other oil-filled equipment (i.e., manufacturing equipment)	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
	☐ Piping and related appurtenances	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
	☐ Mobile refuelers or non-transportation-related tank cars	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
	☐ Transfer areas, equipment and activities	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
	☐ Identify any other equipment or activities that are not listed above:	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
112.7(e)	Inspections and tests conducted in accordance with written procedures	☐ Yes ☐ No	☐ Yes ☐ No
	Record of inspections or tests signed by supervisor or inspector	☐ Yes ☐ No	☐ Yes ☐ No
	Kept with Plan for at least 3 years (see Attachment D of this checklist)[8]	☐ Yes ☐ No	☐ Yes ☐ No
112.7(f)	Personnel, training, and oil discharge prevention procedures		
(1)	Training of oil-handling personnel in operation and maintenance of equipment to prevent discharges; discharge procedure protocols; applicable pollution control laws, rules, and regulations; general facility operations; and contents of SPCC Plan	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
(2)	Person designated as accountable for discharge prevention at the facility and reports to facility management	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
(3)	Discharge prevention briefings conducted at least once a year for oil handling personnel to assure adequate understanding of the Plan. Briefings highlight and describe known discharges as described in §112.1(b) or failures, malfunctioning components, and any recently developed precautionary measures	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA

Comments:

[8] Records of inspections and tests kept under usual and customary business practices will suffice

		PLAN	FIELD
112.7(g)	Plan describes how to: • Secure and control access to the oil handling, processing and storage areas; • Secure master flow and drain valves; • Prevent unauthorized access to starter controls on oil pumps; • Secure out-of-service and loading/unloading connections of oil pipelines; and • Address the appropriateness of security lighting to both prevent acts of vandalism and assist in the discovery of oil discharges	☐ Yes ☐ No ☐ NA *For Oil Production Facilities:* *Select **NA***	☐ Yes ☐ No ☐ NA
112.7(k)	Qualified oil-filled operational equipment is present at the facility[9] *Oil-filled operational equipment means* equipment that includes an oil storage container (or multiple containers) in which the oil is present solely to support the function of the apparatus or the device. Oil-filled operational equipment is not considered a bulk storage container, and does not include oil-filled manufacturing equipment (flow-through process). Examples of oil-filled operational equipment include, but are not limited to, hydraulic systems, lubricating systems (e.g. , those for pumps, compressors and other rotating equipment, including pumpjack lubrication systems), gear boxes, machining coolant systems, heat transfer systems, transformers, circuit breakers, electrical switches, and other systems containing oil solely to enable the operation of the device.	☐ Yes ☐ No	
If YES	Check which apply: Secondary Containment provided in accordance with 112.7(c) ☐ Alternative measure described below (confirm eligibility) ☐		
112.7(k)	Qualified Oil-Filled Operational Equipment • Has a single reportable discharge as described in §112.1(b) from any oil-filled operational equipment exceeding 1,000 U.S. gallons occurred within the three years prior to Plan certification date?	☐ Yes ☐ No ☐ NA	
	• Have two reportable discharges as described in §112.1(b) from any oil-filled operational equipment each exceeding 42 U.S. gallons occurred within any 12-month period within the three years prior to Plan certification date?[10]	☐ Yes ☐ No ☐ NA	
	If **YES** for either, secondary containment in accordance with §112.7(c) is required		
	• Facility procedure for inspections or monitoring program to detect equipment failure and/or a discharge is established and documented	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
	Does not apply if the facility has submitted a FRP under §112.20: • Contingency plan following 40 CFR part 109 (see Attachment E of this checklist) is provided in Plan **AND**	☐ Yes ☐ No ☐ NA	
	• Written commitment of manpower, equipment, and materials required to expeditiously control and remove any quantity of oil discharged that may be harmful is provided in Plan	☐ Yes ☐ No ☐ NA	

Comments:

Inspector Note- Complete, as applicable, either Attachment A or B which include additional requirements based on the type of facility.

[9] This provision does not apply to oil-filled manufacturing equipment (flow-through process)

[10] Oil discharges that result from natural disasters, acts of war, or terrorism are not included in this determination. The gallon amount(s) specified (either 1,000 or 42) refers to the amount of oil that actually reaches navigable waters or adjoining shorelines not the total amount of oil spilled. The entire volume of the discharge is oil for this determination.

ATTACHMENT A ☐ NA **ONSHORE FACILITIES (EXCLUDING PRODUCTION) 40 CFR 112.8/112.12**		**PLAN**	**FIELD**
112.8(b)/ 112.12(b) Facility Drainage			
Diked Areas (1)	Drainage from diked storage areas is: • Restrained by valves, except where facility systems are designed to control such discharge, **OR** • Manually activated pumps or ejectors are used and the condition of the accumulation is inspected prior to draining dike to ensure no oil will be discharged	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
Comments:			
112.8(c)/112.12(c) Bulk Storage Containers ☐ NA *Bulk storage container* means any container used to store oil. These containers are used for purposes including, but not limited to, the storage of oil prior to use, while being used, or prior to further distribution in commerce. Oil-filled electrical, operating, or manufacturing equipment is not a bulk storage container. *If bulk storage containers are not present, mark this section Not Applicable (NA). If present, complete this section and Attachment C of this checklist.*			
(1)	Containers materials and construction are compatible with material stored and conditions of storage such as pressure and temperature	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
(3)	Is there drainage of uncontaminated rainwater from diked areas into a storm drain or open watercourse?	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
If **YES**	Bypass valve normally sealed closed	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
	• Retained rainwater is inspected to ensure that its presence will not cause a discharge as described in §112.1(b)	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
	• Bypass valve opened and resealed under responsible supervision	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
	• Adequate records of drainage are kept; for example, records required under permits issued in accordance with 40 CFR §§122.41(j)(2) and (m)(3)	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
(4)	For completely buried metallic tanks installed on or after January 10, 1974 (if not exempt from SPCC regulation because subject to all of the technical requirements of 40 CFR part 280 or 281):		
	• Provide corrosion protection with coatings or cathodic protection compatible with local soil conditions	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
	• Regular leak testing conducted	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
(5)	The buried section of partially buried or bunkered metallic tanks protected from corrosion with coatings or cathodic protection compatible with local soil conditions	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
Comments:			

ATTACHMENT A		PLAN	FIELD
(6)	Test or inspect each aboveground container for integrity on a regular schedule and whenever you make material repairs. Techniques include, but are not limited to: visual inspection, hydrostatic testing, radiographic testing, ultrasonic testing, acoustic emissions testing, or other system of non-destructive testing	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
	Appropriate qualifications for personnel performing tests and inspections are identified in the Plan and have been assessed in accordance with industry standards	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
	• The frequency and type of testing and inspections are documented, are in accordance with industry standards and take into account the container size, configuration and design	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
	• Comparison records of aboveground container integrity testing are maintained	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
	• Container supports and foundations regularly inspected	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
	• Outside of containers frequently inspected for signs of deterioration, discharges, or accumulation of oil inside diked areas	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
	• Records of all inspections and tests maintained[11]	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
Integrity Testing Standard identified in the Plan:			
112.12 (c)(6)(ii) *(Applies to AFVO Facilities only)*	Conduct formal visual inspection on a regular schedule for bulk storage containers that meet all of the following conditions: • Subject to 21 CFR part 110; • Elevated; • Constructed of austenitic stainless steel; • Have no external insulation; and • Shop-fabricated.	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
	In addition, you must frequently inspect the outside of the container for signs of deterioration, discharges, or accumulation of oil inside diked areas.	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
	You must determine and document in the Plan the appropriate qualifications for personnel performing tests and inspections.[11]	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
(10)	Visible discharges which result in a loss of oil from the container, including but not limited to seams, gaskets, piping, pumps, valves, rivets, and bolts are promptly corrected and oil in diked areas is promptly removed	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
112.8(d)/112.12(d)Facility transfer operations, pumping, and facility process			
(4)	Aboveground valves, piping, and appurtenances such as flange joints, expansion joints, valve glands and bodies, catch pans, pipeline supports, locking of valves, and metal surfaces are inspected regularly to assess their general condition	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
	Integrity and leak testing conducted on buried piping at time of installation, modification, construction, relocation, or replacement	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
Comments:			

[11] Records of inspections and tests kept under usual and customary business practices will suffice

ATTACHMENT B ☐ NA **ONSHORE OIL PRODUCTION FACILITIES—40 CFR 112.9**		**PLAN**	**FIELD**
(Drilling and workover facilities are excluded from the requirements of §112.9) *Production facility* means all structures (including but not limited to wells, platforms, or storage facilities), piping (including but not limited to flowlines or intra-facility gathering lines), or equipment (including but not limited to workover equipment, separation equipment, or auxiliary non-transportation-related equipment) used in the production, extraction, recovery, lifting, stabilization, separation or treating of oil (including condensate), or associated storage or measurement, and is located in an oil or gas field, at a facility. This definition governs whether such structures, piping, or equipment are subject to a specific section of this part.			
112.9(b) Oil Production Facility Drainage			
(1)	At tank batteries, separation and treating areas where there is a reasonable possibility of a discharge as described in §112.1(b), drains for dikes or equivalent measures are closed and sealed except when draining uncontaminated rainwater. Accumulated oil on the rainwater is removed and then returned to storage or disposed of in accordance with legally approved methods	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
	Prior to drainage, diked area inspected and action taken as provided below:		
	• 112.8(c)(3)(ii) - Retained rainwater is inspected to ensure that its presence will not cause a discharge as described in §112.1(b)	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
	• 112.8(c)(3)(iii) - Bypass valve opened and resealed under responsible supervision	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
	• 112.8(c)(3)(iv) - Adequate records of drainage are kept; for example, records required under permits issued in accordance with §122.41(j)(2) and (m)(3)	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
(2)	Field drainage systems (e.g., drainage ditches or road ditches) and oil traps, sumps, or skimmers inspected at regularly scheduled intervals for oil, and accumulations of oil promptly removed	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
112.9(c) Oil Production Facility Bulk Storage Containers *Bulk storage container* means any container used to store oil. These containers are used for purposes including, but not limited to, the storage of oil prior to use, while being used, or prior to further distribution in commerce. Oil-filled electrical, operating, or manufacturing equipment is not a bulk storage container.			
(1)	Containers materials and construction are compatible with material stored and conditions of storage such as pressure and temperature	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
(2)	Except as allowed for flow-through process vessels in §112.9(c)(5) and produced water containers in §112.9(c)(6), secondary containment provided for all tank battery, separation and treating facilities sized to hold the capacity of largest single container and sufficient freeboard for precipitation.	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
	Drainage from undiked area safely confined in a catchment basin or holding pond.	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
(3)	Except as allowed for flow-through process vessels in §112.9(c)(5) and produced water containers in §112.9(c)(6), periodically and upon a regular schedule, visually inspect containers for deterioration and maintenance needs, including foundation and supports of each container on or above the surface of the ground	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
(4)	New and old tank batteries engineered/updated in accordance with good engineering practices to prevent discharges including at least one of the following: • Adequate container capacity to prevent overfill if a pumper/gauger is delayed in making regularly scheduled rounds; • Overflow equalizing lines between containers so that a full container can overflow to an adjacent container; • Adequate vacuum protection to prevent container collapse; or • High level sensors to generate and transmit an alarm to the computer where the facility is subject to a computer production control system	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
Comments:			

ATTACHMENT B		PLAN	FIELD
(5)	**Flow-through Process Vessels.** Alternate requirements in lieu of sized secondary containment required in (c)(2) and requirements in (c)(3) above for facilities with flow-through process vessels:		
(i)	Flow-through process vessels and associated components (e.g. dump valves) are periodically and on a regular schedule visually inspected and/or tested for leaks, corrosion, or other conditions that could lead to a discharge as described in §112.1(b)	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
(ii)	Corrective actions or repairs have been made to flow-through process vessels and any associated components as indicated by regularly scheduled visual inspections, tests, or evidence of an oil discharge	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
(iii)	Oil removed or other actions initiated to promptly stabilize and remediate any accumulation of oil discharges associated with the produced water container	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
(iv)	All flow-through process vessels comply with §§112.9(c)(2) and (c)(3) within six months of any flow-through process vessel discharge of more than 1,000 U.S. gallons of oil in a single discharge as described in §112.1(b) or discharges of more than 42 U.S. gallons of oil in each of two discharges as described in §112.1(b) within any twelve month period.[12]	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
112.9(d) Facility transfer operations, pumping, and facility process			
(1)	All aboveground valves and piping associated with transfer operations are inspected periodically and upon a regular schedule to determine their general condition. Include the general condition of flange joints, valve glands and bodies, drip pans, pipe supports, pumping well polish rod stuffing boxes, bleeder and gauge valves, and other such items	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
(3)	If flowlines and intra-facility gathering lines are not provided with secondary containment in accordance with §112.7(c) and the facility is not required to submit an FRP under §112.20, then the SPCC Plan includes:		
(i)	• An oil spill contingency plan following the provisions of 40 CFR part 109[13]	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
(ii)	• A written commitment of manpower, equipment, and materials required to expeditiously control and remove any quantity of oil discharged that might be harmful	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA

Comments:

[12] Oil discharges that result from natural disasters, acts of war, or terrorism are not included in this determination. The gallon amount(s) specified (either 1,000 or 42) refers to the amount of oil that actually reaches navigable waters or adjoining shorelines not the total amount of oil spilled. The entire volume of the discharge is oil for this determination.

[13] Note that the implementation of a 40 CFR part 109 plan does not require a PE impracticability determination for this specific requirement.

ATTACHMENT B		PLAN	FIELD
(4)	A flowline/intra-facility gathering line maintenance program to prevent discharges is prepared and implemented and includes the following procedures:		
(i)	Flowlines and intra-facility gathering lines and associated valves and equipment are compatible with the type of production fluids, their potential corrosivity, volume, and pressure, and other conditions expected in the operational environment	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
(ii)	Flowlines and intra-facility gathering lines and associated appurtenances are visually inspected and/or tested on a periodic and regular schedule for leaks, oil discharges, corrosion, or other conditions that could lead to a discharge as described in §112.1(b).	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
	If flowlines and intra-facility gathering lines are not provided with secondary containment in accordance with §112.7(c), the frequency and type of testing allows for the implementation of a contingency plan as described under 40 CFR 109 or an FRP submitted under §112.20	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
(iii)	Repairs or other corrective actions are made to any flowlines and intra-facility gathering lines and associated appurtenances as indicated by regularly scheduled visual inspections, tests, or evidence of a discharge	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
(iv)	Oil removed or other actions initiated to promptly stabilize and remediate any accumulation of oil discharges associated with the produced water containers	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
ATTACHMENT B ☐ NA **ONSHORE OIL DRILLING AND WORKOVER FACILITIES—40 CFR 112.10**		**PLAN**	**FIELD**
112.10(b)	Mobile drilling or workover equipment is positioned or located to prevent a discharge as described in §112.1(b)	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
112.10(c)	Catchment basins or diversion structures are provided to intercept and contain discharges of fuel, crude oil, or oily drilling fluids	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
112.10(d)	Blowout prevention (BOP) assembly and well control system installed before drilling below any casing string or during workover operations	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA
	BOP assembly and well control system is capable of controlling any well-head pressure that may be encountered while on the well	☐ Yes ☐ No ☐ NA	☐ Yes ☐ No ☐ NA

Comments:

This page left intentionally blank.

ATTACHMENT C: SPCC FIELD INSPECTION AND PLAN REVIEW TABLE

Documentation of Field Observations for Containers and Associated Requirements

Inspectors should use this table to document observations of containers as needed.

Containers and Piping

Check containers for leaks, specifically looking for: drip marks, discoloration of tanks, puddles containing spilled or leaked material, corrosion, cracks, and localized dead vegetation, and standards/specifications of construction.

Check aboveground container foundation for: cracks, discoloration, and puddles containing spilled or leaked material, settling, gaps between container and foundation, and damage caused by vegetation roots.

Check all piping for: droplets of stored material, discoloration, corrosion, bowing of pipe between supports, evidence of stored material seepage from valves or seals, evidence of leaks, and localized dead vegetation. For all aboveground piping, include the general condition of flange joints, valve glands and bodies, drip pans, pipe supports, bleeder and gauge valves, and other such items (Document in comments section of §112.8(d) or 112.12(d).)

Secondary Containment (Active and Passive)

Check secondary containment for: containment system (including walls and floor) ability to contain oil such that oil will not escape the containment system before cleanup occurs, proper sizing, cracks, discoloration, presence of spilled or leaked material (standing liquid), erosion, corrosion, penetrations in the containment system, and valve conditions.

Check dike or berm systems for: level of precipitation in dike/available capacity, operational status of drainage valves (closed), dike or berm impermeability, debris, erosion, impermeability of the earthen floor/walls of diked area, and location/status of pipes, inlets, drainage around and beneath containers, presence of oil discharges within diked areas.

Check drainage systems for: an accumulation of oil that may have resulted from any small discharge, including field drainage systems (such as drainage ditches or road ditches), and oil traps, sumps, or skimmers. Ensure any accumulations of oil have been promptly removed.

Check retention and drainage ponds for: erosion, available capacity, presence of spilled or leaked material, debris, and stressed vegetation.

Check active measures (countermeasures) for: amount indicated in plan is available and appropriate; deployment procedures are realistic; material is located so that they are readily available; efficacy of discharge detection; availability of personnel and training, appropriateness of measures to prevent a discharge as described in §112.1(b). *Note that appropriate evaluation and consideration must be given to the any use of active measures at an unmanned production facility.*

Container ID/ General Condition[14] Aboveground or Buried Tank	Storage Capacity and Type of Oil	Type of Containment/ Drainage Control	Overfill Protection and Testing & Inspections

[14] Identify each tank with either an A to indicate aboveground or B for completely buried

ATTACHMENT C: SPCC FIELD INSPECTION AND PLAN REVIEW TABLE (CONT.)

Documentation of Field Observations for Containers and Associated Requirements

Container ID/ General Condition[15] Aboveground or Buried Tank	Storage Capacity and Type of Oil	Type of Containment/ Drainage Control	Overfill Protection and Testing & Inspections

[15] Identify each tank with either an A to indicate aboveground or B for completely buried

ATTACHMENT D: SPCC INSPECTION AND TESTING CHECKLIST

Required Documentation of Tests and Inspections

Records of inspections and tests required by 40 CFR part 112 signed by the appropriate supervisor or inspector must be kept by all facilities with the SPCC Plan for a period of three years. Records of inspections and tests conducted under usual and customary business practices will suffice. Documentation of the following inspections and tests should be kept with the SPCC Plan.

	Inspection or Test	Documentation		Not Applicable
		Present	Not Present	
112.6—Tier I Qualified Facilities				
(a)(3)(iii)	Regular testing of system or documented procedures used instead of liquid level sensing devices specified in §§112.8(c)(8) and 112.12(c)(8) to prevent container overfills	☐	☐	☐
112.7–General SPCC Requirements				
k(2)(i)	Inspection or monitoring of qualified oil-filled operational equipment when the equipment meets the qualification criteria in §112.7(k)(1) and facility owner/operator chooses to implement the alternative requirements in §112.7(k)(2) that include an inspection or monitoring program to detect oil-filled operational equipment failure and discharges	☐	☐	☐
112.8/112.12–Onshore Facilities (excluding oil production facilities)				☐ NA
(b)(1), (b)(2)	Inspection of storm water released from diked areas into facility drainage directly to a watercourse	☐	☐	☐
(c)(3)	Inspection of rainwater released directly from diked containment areas to a storm drain or open watercourse before release, open and release bypass valve under supervision, and records of drainage events	☐	☐	☐
(c)(4)	Regular leak testing of completely buried metallic storage tanks installed on or after January 10, 1974 and regulated under 40 CFR 112	☐	☐	☐
(c)(6)	Regular integrity testing of aboveground containers and integrity testing after material repairs, including comparison records	☐	☐	☐
(c)(6), (c)(10)	Regular visual inspections of the outsides of aboveground containers, supports and foundations	☐	☐	☐
(c)(6)	Frequent inspections of diked areas for accumulations of oil	☐	☐	☐
(d)(4)	Regular inspections of aboveground valves, piping and appurtenances and assessments of the general condition of flange joints, expansion joints, valve glands and bodies, catch pans, pipeline supports, locking of valves, and metal surfaces	☐	☐	☐
(d)(4)	Integrity and leak testing of buried piping at time of installation, modification, construction, relocation or replacement	☐	☐	☐
112.9–Onshore Oil Production Facilities (excluding drilling and workover facilities)				☐ NA
(b)(1)	Rainwater released directly from diked containment areas inspected following §§112.8(c)(3)(ii), (iii) and (iv), including records of drainage kept	☐	☐	☐
(b)(2)	Field drainage systems, oil traps, sumps, and skimmers inspected regularly for oil, and accumulations of oil promptly removed	☐	☐	☐
(c)(3)	Containers, foundations and supports inspected visually for deterioration and maintenance needs	☐	☐	☐
(c)(5)(i)	In lieu of having sized secondary containment, flow-through process vessels and associated components visually inspected and/or tested periodically and on a regular schedule for conditions that could result in a discharge as described in §112.1(b)	☐	☐	☐
(d)(1)	All aboveground valves and piping associated with transfers are regularly inspected	☐	☐	☐
(d)(4)(ii)	For flowlines and intra-facility gathering lines without secondary containment, in accordance with §112.7(c), lines are visually inspected and/or tested periodically and on a regular schedule to allow implementing the part 109 contingency plan or the FRP submitted under §112.20	☐	☐	☐

This page left intentionally blank.

ATTACHMENT E: SPCC CONTINGENCY PLAN REVIEW CHECKLIST

☐ NA

40 CFR Part 109–Criteria for State, Local and Regional Oil Removal Contingency Plans

If SPCC Plan includes an impracticability determination for secondary containment in accordance with §112.7(d), the facility owner/operator is required to provide an oil spill contingency plan following 40 CFR part 109, unless he or she has submitted a FRP under §112.20. An oil spill contingency plan may also be developed, unless the facility owner/operator has submitted a FRP under §112.20 as one of the required alternatives to general secondary containment for qualified oil filled operational equipment in accordance with §112.7(k).

	109.5–Development and implementation criteria for State, local and regional oil removal contingency plans[16]	**Yes**	**No**
(a)	Definition of the authorities, responsibilities and duties of all persons, organizations or agencies which are to be involved in planning or directing oil removal operations.	☐	☐
(b)	Establishment of notification procedures for the purpose of early detection and timely notification of an oil discharge including:	☐	☐
(1)	The identification of critical water use areas to facilitate the reporting of and response to oil discharges.	☐	☐
(2)	A current list of names, telephone numbers and addresses of the responsible persons (with alternates) and organizations to be notified when an oil discharge is discovered.	☐	☐
(3)	Provisions for access to a reliable communications system for timely notification of an oil discharge, and the capability of interconnection with the communications systems established under related oil removal contingency plans, particularly State and National plans (e.g., National Contingency Plan (NCP)).	☐	☐
(4)	An established, prearranged procedure for requesting assistance during a major disaster or when the situation exceeds the response capability of the State, local or regional authority.	☐	☐
(c)	Provisions to assure that full resource capability is known and can be committed during an oil discharge situation including:	☐	☐
(1)	The identification and inventory of applicable equipment, materials and supplies which are available locally and regionally.	☐	☐
(2)	An estimate of the equipment, materials and supplies that would be required to remove the maximum oil discharge to be anticipated.	☐	☐
(3)	Development of agreements and arrangements in advance of an oil discharge for the acquisition of equipment, materials and supplies to be used in responding to such a discharge.	☐	☐
(d)	Provisions for well-defined and specific actions to be taken after discovery and notification of an oil discharge including:	☐	☐
(1)	Specification of an oil discharge response operating team consisting of trained, prepared and available operating personnel.	☐	☐
(2)	Pre-designation of a properly qualified oil discharge response coordinator who is charged with the responsibility and delegated commensurate authority for directing and coordinating response operations and who knows how to request assistance from Federal authorities operating under existing national and regional contingency plans.	☐	☐
(3)	A preplanned location for an oil discharge response operations center and a reliable communications system for directing the coordinated overall response operations.	☐	☐
(4)	Provisions for varying degrees of response effort depending on the severity of the oil discharge.	☐	☐
(5)	Specification of the order of priority in which the various water uses are to be protected where more than one water use may be adversely affected as a result of an oil discharge and where response operations may not be adequate to protect all uses.	☐	☐
(e)	Specific and well defined procedures to facilitate recovery of damages and enforcement measures as provided for by State and local statutes and ordinances.	☐	☐

[16] The contingency plan should be consistent with all applicable state and local plans, Area Contingency Plans, and the NCP.

This page left intentionally blank.

ATTACHMENT F: ADDITIONAL COMMENTS

ATTACHMENT F: ADDITIONAL COMMENTS (CONT.)

ATTACHMENT G: PHOTO DOCUMENTATION NOTES

Photo#	Photographer Name	Time of Photo Taken	Compass Direction	Description

ATTACHMENT G: PHOTO DOCUMENTATION NOTES (CONT.)

Photo#	Photographer Name	Time of Photo Taken	Compass Direction	Description

Appendix H: Other Policy Documents

- Memorandum, *Use of Alternative Secondary Containment Measures at Facilities Regulated under the Oil Pollution Prevention Regulation (40 CFR Part 112)*, OSWER 9360.8-37, Don R. Clay, OSWER Assistant Administrator, April 29, 1992.
- EPA Liner Study: Report to Congress, Section 4113(a) of the Oil Pollution Act of 1990. May 1996.
- David Lopez, Letter to Mr. Chris Early of Safety-Kleen Corporation, July 14, 2000.
- Stephen F. Heare, Letter to Melissa Young of Petroleum Marketers Association of America, 2001.
- Memorandum, *Use of Alternative Secondary Containment Measures at Facilities Regulated under the Oil Pollution Prevention Regulation (40 CFR Part 112)*, OSWER 9360.8-38, Marianne Lamont Horinko, OSWER Assistant Administrator, August 9, 2002.
- Advance Notice of Proposed Rulemaking on the Clean Water Act Regulatory Definition of ''Waters of the United States'', 68 FR 1991, January 15, 2003.
- Marianne Horinko, Letter to Daniel Gilligan of Petroleum Marketers Association of America, May 25, 2004.
- Susan Parker Bodine, Letter to Brian Jennings of American Coalition for Ethanol, November 7, 2006.
- Memorandum, *Clean Water Act Jurisdiction following the U.S . Supreme Court's Decision in Rapanos v. United States & Carabell v. United States*, December 2, 2008.
- R. Craig Matthiessen, Letter to Roger Claff, December 10, 2010.
- EPA Jurisdiction at Complexes, August 2013.
- FRP Rule Attachment C-I: *Flowchart of Criteria for Substantial Harm*, 40 CFR Ch. I, Pt. 112, App. C.
- FRP Rule Attachment C-II: *Calculation of the Planning Distance*, 40 CFR Ch. I, Pt. 112, App. C.
- Example: Spill Prevention Control and Countermeasure (SPCC) Plan - Construct New Secondary Containment, July 2011

- Example: Spill Prevention Control and Countermeasure (SPCC) Plan - Multiple Horizontal Cylindrical Tanks Inside a Rectangular or Square Dike or Berm, July 2011
- Example: Spill Prevention Control and Countermeasure (SPCC) Plan - Rectangular or Square Remote Impoundment Structure, July 2011
- Example: Spill Prevention Control and Countermeasure (SPCC) Plan - Single Vertical Cylindrical Tank Inside a Rectangular or Square Dike or Berm, July 2011
- Worksheet: Spill Prevention Control and Countermeasure (SPCC) Plan - Construct New Secondary Containment, July 2011
- Worksheet: Spill Prevention Control and Countermeasure (SPCC) Plan - Multiple Horizontal Cylindrical Tanks Inside a Rectangular or Square Dike or Berm, July 2011
- Worksheet: Spill Prevention Control and Countermeasure (SPCC) Plan - Rectangular or Square Remote Impoundment Structure, July 2011
- Worksheet: Spill Prevention Control and Countermeasure (SPCC) Plan - Single Vertical Cylindrical Tank Inside a Rectangular or Square Dike or Berm, July 2011

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C. 20460

APR 29 1992

OFFICE OF
SOLID WASTE AND EMERGENCY RESPONSE

MEMORANDUM

SUBJECT: Use of Alternative Secondary Containment Measures at Facilities Regulated under the Oil Pollution Prevention Regulation (40 CFR Part 112)

FROM: Don R. Clay
Assistant Administrator

TO: Director, Environmental Services Division
Regions I, VI, VII
Director, Emergency and Remedial Response Division
Region II
Director, Hazardous Waste Management Division
Regions III, IX
Director, Waste Management Division
Regions IV, V, VIII
Director, Hazardous Waste Division
Region X

PURPOSE

This memorandum addresses the U.S. Environmental Protection Agency's (EPA) interpretation of the term "secondary containment" as it is used in section 112.7(c) of the Oil Pollution Prevention regulation (40 CFR Part 112), also known as the Spill Prevention, Control and Countermeasures (SPCC) regulation. It also addresses technologies that may be used to provide secondary containment for smaller, shop-fabricated aboveground storage tanks (ASTs) consistent with 40 CFR Part 112.7(c).

BACKGROUND

Since 1973, the SPCC regulation has included the following provision addressing secondary containment and the allowance for equivalent preventive systems. Section 112.7(c) states:

> Appropriate containment and/or diversionary structures or equipment to prevent discharged oil from reaching a navigable water course should be provided. One of the following preventive systems or its equivalent should be

used as a minimum: (1) Onshore facilities: (i) Dikes, berms or retaining walls sufficiently impervious to contain spilled oil; (ii) Curbing; (iii) Culverting, gutters or other drainage systems; (iv) Weirs, booms or other barriers; (v) Spill diversion ponds; (vi) Retention ponds; (vii) Sorbent materials.

The SPCC regulation implements Section 311(j)(1)(C) of the Clean Water Act (CWA) for non-transportation-related facilities. In 1988, the Agency published regulations at 40 CFR Part 280 for underground storage tanks (USTs) implementing the requirements of Subtitle I of the Resource Conservation and Recovery Act. An apparent result of the implementation of the UST regulation is a trend of facilities replacing USTs with ASTs.

In response to this trend, tank manufacturers have developed various new designs for shop-fabricated AST systems. Alternative AST systems for which we have information generally do not exceed 12,000 gallons capacity. Some of these new designs include a steel or reinforced concrete secondary shell fully encasing a storage tank; others include an attached, shop-fabricated containment dike. Many other system designs may also be available. Typically, these alternative AST system designs provide containment for the entire capacity of the inner tank for spills resulting from leaks or ruptures of the inner tank.

In 1988, EPA noted in its Oil SPCC Program Task Force Report that the Agency has limited inspection resources to implement the SPCC program. Less than 1,000 of the estimated half million SPCC-regulated facilities are inspected by EPA annually. Moreover, section 311 of the CWA does not permit EPA to delegate this program to the States. The Task Force, therefore, recommended that EPA attempt to target these very limited resources to inspecting the highest-risk facilities. In general, we believe that facilities using smaller-volume AST systems generally pose less risk than larger field-erected tanks and tank farms of large uncontrolled spills reaching navigable waters, especially if these facilities are not located near sensitive ecosystems or water supply intakes.

The traditional method of providing secondary containment for ASTs has been to construct dikes, berms, retaining walls and/or diversion ponds to collect oil once it spills. Based on the experience of EPA Regional personnel implementing the SPCC regulation since 1973, those traditional means of secondary containment are very effective and reliable methods of protecting the surface waters from oil spills from ASTs. However, the SPCC regulation is a performance-based regulation that permits facility owners or operators to substitute alternative forms of spill containment if they provide protection against discharges to navigable waters substantially equivalent to that provided by the systems listed in section 112.7(c).

Consistent with section 112.1(e) of the SPCC regulation, this memorandum does not supersede the authority of "existing laws, regulations, rules, standards, policies and procedures pertaining to safety standards, fire prevention and pollution rules," including fire codes or other standards for good engineering practice that may apply to alternative AST systems.

On October 22, 1991, EPA proposed revisions to the SPCC regulation. The proposed revisions do not affect the provisions of section 112.7(c) that describe alternative systems that are substantially equivalent to those specifically listed in paragraphs (c)(1)(i) through (c)(1)(vii).

OBJECTIVE

This memorandum should allow EPA Regional personnel to provide consistent interpretation of the secondary containment provisions of section 112.7(c) of the SPCC regulation to facilities with generally smaller shop-fabricated ASTs. Alternative AST systems, including equipment and procedures to prevent reasonably expected discharges, should satisfy the secondary containment provisions of the SPCC regulation under most site-specific conditions.

DISCUSSION

As smaller shop-fabricated ASTs are increasingly appearing in the market, we have observed a number of innovative technologies to reduce the risks of both leaks and spills. Moreover, these smaller shop-fabricated tanks do not pose the same risk of large uncontrolled oil spills to navigable waters as the larger field-erected tanks. Therefore, we believe that there should be many situations in which protection of navigable waters substantially equivalent to that provided by the secondary containment systems listed in section 112.7(c) could be provided by alternative AST systems that have capacities generally less than 12,000 gallons and are installed and operated with protective measures other than secondary containment dikes. For example, some State programs provide an exemption from State spill prevention requirements for ASTs with similar capacities. However, in certain situations, these alternative AST systems might appropriately not be presumed to comply with the provisions of section 112.7(c). An example of this type of situation is facilities containing four or more ASTs or ASTs with combined capacity greater than 40,000 gallons, where a number of larger tanks are connected by manifolds or other piping arrangements

that would permit a volume of oil greater than the capacity of one tank to be spilled as a result of a single system failure.[1]

The owner or operator of any facility subject to the SPCC regulation, including facilities using alternative AST systems, must adhere to all applicable provisions of the SPCC regulation. The owner or operator of each regulated facility must develop a site-specific SPCC Plan that must be certified by a Registered Professional Engineer as required by section 112.3 of the regulation. Pursuant to the requirement of section 112.7 that the SPCC Plan shall "include a discussion of the facility's conformance with the appropriate guidelines listed," a complete SPCC Plan for any facility using alternative AST systems should include a discussion of why the facility is considered to be in conformance with section 112.7(c).

In evaluating these shop-fabricated AST systems, EPA's Office of Solid Waste and Emergency Response (OSWER) has looked at requirements the Agency has established for tanks in situations where traditional secondary containment systems cannot be provided (e.g., USTs covered by 40 CFR Part 280). Additionally, OSWER has evaluated relevant State and local government requirements. OSWER also has considered factors related to alternative AST systems, including tank size, typical pumping rates used to fill and empty them, and the lower risk of large, uncontrolled oil spills from facilities using such AST systems, based on tank size, design, and pumping rates. We believe that for these smaller shop-fabricated ASTs some alternative AST systems that include adequate technical spill and leak prevention options such as overfill alarms, flow shutoff or restrictor devices, and constant monitoring of product transfers generally would allow owners and operators of facilities to provide protection of navigable waters substantially equivalent to that provided by secondary containment as defined in 40 CFR Part 112.7(c). For example, small double walled ASTs, when used with equipment and procedures described in this guidance, generally would provide substantially equivalent protection of navigable waters under section 112.7(c) of the SPCC regulation when the inner tank is an Underwriters' Laboratory-listed steel tank, the outer wall is constructed in accordance with nationally accepted industry standards (e.g., those codified by the American Petroleum Institute, the Steel Tank Institute, and American Concrete Institute), the tank has overfill prevention measures that include an overfill alarm and an automatic flow restrictor

---

[1] This is based on similar capacities in proposed National Fire Protection Association standards and consideration of the risks to public health or welfare or the environment of spills of potentially larger size.

or flow shut-off,[2] and all product transfers are constantly monitored.[3]

CONCLUSION

When the only significant source of potential oil spills to navigable waters of the United States from a facility is from alternative ASTs as described in this memorandum, an SPCC Plan that is certified by a Registered Professional Engineer and that requires equipment and operating practices in accordance with good engineering practice and the principle of substantial equivalence as described above should be presumed to achieve the protection of navigable waters substantially equivalent to that provided by the preventive systems specified in 40 CFR Part 112.7(c).

cc: Bowdoin Train
Henry Longest
Bruce Diamond
Deborah Dietrich
Walter Kovalick
James Makris
Charles Openchowski
David Ziegele
Wendy Butler
Removal Managers, Regions I-X

---

[2] Consistent with the performance standards for these devices as described in section 280.20(c) of EPA regulations for USTs at 40 CFR Part 280 and in an August 5, 1991, amendment, an automatic flow shut-off will shut off flow so that none of the fittings located on top of the tank are exposed to product as a result of overfilling, an automatic flow restrictor will restrict flow 30 minutes prior to overfill or when the tank is no more than 90 percent full, and a high level alarm will alert the operator one minute before overfilling or when the tank is no more than 90 percent full.

[3] Consistent with the performance standard for overfill control as described in section 280.30(a) of EPA regulations for USTs at 40 CFR Part 280, an owner/operator of the facility will ensure that the transfer operation is monitored constantly to prevent overfilling and spilling.

TOTAL P.06

SPCC-7-7-11

OSWER 9380.0-24
EPA 540/R95/041
PB95-963538

United States Environmental Protection Agency

EPA LINER STUDY

Report to Congress

Section 4113(a) of the Oil Pollution Act of 1990

May 1996

TABLE OF CONTENTS

Page

ACRONYMS v

EXECUTIVE SUMMARY vii

PURPOSE vii

SCOPE OF THE STUDY vii

SUMMARY OF FINDINGS viii

Universe of Facilities viii
Evidence of Spills ix
Technical Feasibility x

RECOMMENDATIONS xii

1. INTRODUCTION 1

1.1 PURPOSE 1

1.2 BACKGROUND 1

1.3 STUDY APPROACH 2

1.4 ORGANIZATION OF REPORT 3

2. BACKGROUND ON ASTs 5

2.1 PROFILE OF AST FACILITIES AND ASTs 5

2.1.1 Profile of AST Facilities 5
2.1.2 Profile of ASTs 9

2.2 OIL DISCHARGES FROM ASTs 11

2.3 STATUS OF ASTs NATIONWIDE 15

2.3.1 Federal Reporting Requirements 17
2.3.2 Discharges from ASTs 18
2.3.3 Age Profile of ASTs 19

TABLE OF CONTENTS (Continued)

3. EXISTING REGULATIONS AND INDUSTRY PRACTICES FOR LINER SYSTEMS 25

3.1 REVIEW OF FEDERAL AND STATE AST REGULATIONS 25

3.1.1 Federal Regulations 25
3.1.2 State Regulations 26

3.2 INDUSTRY PRACTICES AND STANDARDS 33

3.3 ESTIMATE OF THE NUMBER OF FACILITIES ALREADY USING LINERS OR RELATED SYSTEMS 34

4. TECHNICAL FEASIBILITY AND UNIT COST OF LINERS AND RELATED SYSTEMS 37

4.1 OVERVIEW 37

4.2 DESCRIPTION OF MODEL FACILITIES 37

4.3 LINER SYSTEM DESIGNS AND PRACTICES 48

4.3.1 Liner Materials Currently in Use 50
4.3.2 Cost of Liners 50
4.3.3 Liner Use Practices 50
4.3.4 Liner Effectiveness 51
4.3.5 Liner Designs Used in this Study 52

4.4 LINER FEASIBILITY EVALUATION 59

4.4.1 Protection of the Environment and Construction Ease 61
4.4.2 Estimated Facility Costs 62

4.5 LEAK DETECTION METHODS 67

5. RECOMMENDATIONS 69

REFERENCES 73

APPENDIX A: STATE REGULATIONS 75

APPENDIX B: MODEL FACILITIES 79

LIST OF EXHIBITS

Title		Page
Exhibit 2-1:	Estimated Number of Facilities Meeting the SPCC Storage Capacity Thresholds	7
Exhibit 2-2:	Distribution of ASTs by Age Category	12
Exhibit 2-3:	Distribution of ASTs by Storage Capacity Tier	13
Exhibit 2-4:	Distribution of ASTs by Storage Capacity by Data Source	14
Exhibit 2-5:	Case Studies	16
Exhibit 2-6:	Percentage of ASTs by Age Category	20
Exhibit 2-7:	Percent Corrosion Failure in Each Age Group	22
Exhibit 3-1:	Summary of State Regulatory Review for the Nine States	27
Exhibit 3-2:	Estimated Number of Facilities Not Currently Required to Install Liners	35
Exhibit 4-1:	Model Facility 1: Small End User - Supply	39
Exhibit 4-2:	Model Facility 2: Small End User - Storage/Motor Fuel	40
Exhibit 4-3:	Model Facility 3: Small Bulk Storage - Distribution	41
Exhibit 4-4:	Model Facility 4: Medium Bulk Storage - Distribution	42
Exhibit 4-5:	Model Facility 5: Large Bulk Storage - Distribution	43
Exhibit 4-6:	Model Facility 6: Large Oil Terminal - Distribution	44
Exhibit 4-7:	Summary of Characteristics of Model Facilities	45
Exhibit 4-8:	Categorization of Facilities Not Currently Required to Install Liners	47

LIST OF EXHIBITS (Continued)

Title		Page
Exhibit 4-9:	General Schematic: Aboveground Storage Facility	53
Exhibit 4-10:	Details: Containment Dike and Liner	54
Exhibit 4-11:	Details: Liner at Base of Vertical Tank	55
Exhibit 4-12:	Details: Foundation Penetration	56
Exhibit 4-13:	Details: Access Road	57
Exhibit 4-14:	Details: Undertank Containment System	58
Exhibit 4-15:	Comparative Analysis of Liners for Environmental Protection and Construction Ease	60
Exhibit 4-16:	Comparative Cost Analysis of Liner Materials by Model Facility	63
Exhibit 4-17:	Annual Operation and Maintenance Costs	64
Exhibit 4-18:	Estimated Liner Capital Cost Per Gallon of Storage Capacity	66
Exhibit A-1:	State Regulations	76
Exhibit B-1:	Typical Storage Capacities for Facilities from Previous EPA Analysis	79
Exhibit B-2:	Categorization of Facilities Not Currently Required to Install Liners	80

ACRONYMS

API	American Petroleum Institute
AST	Aboveground Storage Tank
CERCLA	Comprehensive Environmental Response, Compensation, and Liability Act
CFR	Code of Federal Regulations
CWA	Clean Water Act
DOT	Department of Transportation
EPA	Environmental Protection Agency
ERNS	Emergency Response Notification System
GCS	Ground Water Characterization Study
HDPE	High Density Polyethylene
HMTA	Hazardous Materials Transportation Act
HWST	Federal Hazardous Waste Storage Tank
MMS	Minerals Management Service
NFPA	National Fire Protection Association's Flammable and Combustible Liquids Code
NRC	National Response Center
ODCP	Oil Discharge Contingency Plan
OPA	Oil Pollution Act
OSC	On-Scene Coordinator
PVC	Polyvinyl chloride
RCRA	Resource Conservation and Recovery Act
SPCC	Spill Prevention, Control, and Countermeasures
SIC	Standard Industrial Classification
UST	Underground Storage Tank
VADEQ	Virginia Department of Environmental Quality

EXECUTIVE SUMMARY

PURPOSE

Section 4113(a) of the Oil Pollution Act of 1990 (OPA) requires that: "The President shall conduct a study to determine whether liners or other secondary means of containment should be used to prevent leaking or to aid in leak detection at onshore facilities used for the bulk storage of oil and located near navigable waters." In Executive Order 12777, the President delegated authority to the U.S. Environmental Protection Agency (EPA) to conduct this study.

EPA investigated the nature and magnitude of leaking oil at onshore facilities with aboveground storage tanks (ASTs) that are used for the bulk storage of oil and that are located near navigable waters. The Agency also assessed the technical feasibility of using liners and related systems to detect leaking oil and to prevent leaking oil from contaminating soil and, by way of ground-water pathways, navigable waters. This report to Congress, which presents the findings and recommendations of EPA's study, fulfills the requirements of Section 4113(a) of the OPA.

SCOPE OF THE STUDY

After the OPA became law, EPA staff from the Offices of Emergency and Remedial Response and Congressional Liaison met with Congressional staff to discuss the scope of the study to be conducted under OPA Section 4113(a). Based on these discussions, the Agency decided that the study would focus on the feasibility of using liners and related systems to address oil leaking from ASTs to secondary containment structures (e.g., berms, dikes) and to soil underneath ASTs. An assessment of the feasibility of using liners to address oil leaking from other parts of AST facilities, such as tank truck transfer racks and underground piping, was not specifically addressed during the study. However, because underground piping was identified as a significant potential source of leaking oil at AST facilities, the Agency's recommendations also address this source of contamination.

For this study, EPA defined a liner as an engineered system that makes secondary containment structures more impervious. EPA assessed the technical feasibility of installing liners made from synthetic materials as well as earthen materials within secondary containment structures and under ASTs (i.e., undertank liners). EPA also assessed the feasibility of installing double bottoms on vertical ASTs as "other secondary means of containment," which could be used in place of undertank liners. The Agency also examined other technologies to aid in leak detection and looked at available data on liner costs.

EPA evaluated the effectiveness of liners and double bottoms in reducing the potential for leaking oil to reach soil and navigable waters (i.e., surface waters) via ground-water pathways. Oil discharges to unlined secondary containment systems, such as episodic spills, and continuous leaks from the bottoms of ASTs may contaminate soil and have the potential to be transported downward to ground water. Because ground water often is hydrologically connected to surface water, a ground-water oil plume has the potential to migrate and contaminate surface water. Furthermore, oil that repeatedly contaminates soil as a result of frequent spills may form oil-saturated soil zones, which have the potential to contaminate surface water when precipitation migrates through soil to surface-water bodies. Based on these considerations, EPA assessed the suitability of using liner systems to protect ground water and, in turn, navigable waters by evaluating the effectiveness of these systems in preventing discharged oil from contaminating soil and ground water.

SUMMARY OF FINDINGS

Universe of Facilities

EPA estimates that 502,000 onshore facilities have ASTs and store significant quantities of oil in bulk. Approximately 435,000 of these facilities are required by EPA's Oil Pollution Prevention regulation (40 CFR Part 112) to develop written plans to prevent and control oil discharges and install secondary containment systems for ASTs.[1] EPA estimates that the number of ASTs located at these 502,000 onshore facilities is about 1.8 million. A separate study conducted for the American Petroleum Institute (API) estimates that about 700,000 ASTs are used at facilities in the production, refining, transportation, and marketing sectors of the petroleum industry.[2]

In general, there are two categories of ASTs: (1) vertical ASTs, which are mounted such that the tank bottom rests on a foundation at ground level; and (2) horizontal ASTs, which are supported in saddles such that the tank is suspended above the ground or floor of a secondary containment structure. The storage capacity of horizontal ASTs typically ranges from a few hundred gallons up to 20,000 gallons, while the storage capacity of vertical ASTs typically ranges from several thousand gallons to

[1] The Oil Pollution Prevention regulation (40 CFR Part 112) was initially promulgated on December 11, 1973. After passage of the OPA, two sets of revisions to the regulation were developed. The first set of revisions was proposed on October 22, 1991 (56 FR 54612) in order to clarify the applicability of the regulation. The second set of revisions was promulgated on July 1, 1994 (59 FR 34070) to establish requirements for the development of facility response plans (FRPs). The requirements to develop SPCC plans and to install secondary containment, as referenced in this document, are included in the original regulation. For information on state regulations for liners, see Chapter 3 and Appendix A of this document.

[2] American Petroleum Institute (API), "Aboveground Storage Tank Survey," prepared by Entropy Limited, April 1989. This study did not include ASTs at end-user facilities.

over 10 million gallons. All ASTs have the potential to leak oil, presenting the threat of environmental contamination.

Evidence of Spills

EPA searched for existing data to estimate the number of leaking ASTs, volume discharged, and resulting environmental damage. The Agency found that comprehensive data do not exist to adequately quantify the extent to which the nation's AST inventory is leaking. Existing Federal regulations require facility owners and operators to report oil discharges only if they trigger the reporting thresholds of Clean Water Act (CWA) regulations. Consequently, some leaking oil that contaminates soil and ground water may not be reported to Federal authorities and, therefore, may not be recorded in national spill data bases, such as EPA's Emergency Response Notification System (ERNS).

Existing sources of information evaluated by EPA, however, do indicate that a significant number of ASTs may be leaking or spilling oil. For example, analysis of ERNS data indicate that about 30 percent of all reported oil discharges from onshore facilities, or approximately 1,700 spills annually, are to secondary containment areas, many of which are believed to be unlined. The results of a recent API survey indicate that 85 percent of refineries, 68 percent of marketing facilities, and 10 percent of transportation facilities have known ground-water contamination near their facilities.[3] Some of these facilities store millions of gallons of oil in ASTs. A preliminary report issued by the Virginia Department of Environmental Quality containing statistics on 88 facilities that have 1 million gallons or more of aboveground storage capacity indicates that 88 percent of these facilities reported ground-water contamination.[4] It is not clear from these data whether this oil contamination is caused by past practices or is continuing to occur at these facilities. For example, the results of the API survey referenced above indicate that changes in operation practices, upgraded standards, and improved equipment have significantly reduced reported petroleum spills and accidental releases from ASTs. Spill data also do not allow EPA to determine the extent of oil contamination caused by different sizes or types of facilities. Furthermore, the data are not sufficiently detailed to determine whether the contamination is caused by oil discharging from ASTs or from other areas of the facility. EPA found during the course of this study that underground piping located at onshore facilities also is a potentially significant source of leaking oil. As one indicator of the number of ASTs that could be leaking oil and the corresponding volume discharged, EPA obtained data on AST age and examined the potential relationship between AST age and corrosion rates to estimate the likelihood that ASTs will develop leaks as a function of tank age.

[3] American Petroleum Institute (API), "A Survey of API Members' Aboveground Storage Tank Facilities," prepared by API Health and Environmental Affairs Department, July 1994.

[4] Virginia Department of Environmental Quality (VADEQ), "The Virginia DEQ Aboveground Storage Tank Regulations," April 4, 1994.

Technical Feasibility

EPA investigated the technical feasibility of liner systems, including double bottoms, by examining the effectiveness of different liner materials and designs for protecting the environment from oil discharges and evaluating the construction feasibility of liner systems. The technical feasibility and unit-cost analysis are based on alternative liner designs for six "model" facilities used to represent the diverse universe of facilities potentially benefitting from liner system installation. These model facilities ranged from small end-user facilities with one horizontally mounted 2,000-gallon AST to a large petroleum bulk terminal with several vertical ASTs with a combined storage capacity of about 50 million gallons. For these model facilities, the alternative designs considered and evaluations of their effectiveness were based largely on discussions with EPA On-Scene Coordinators and owners and operators of facilities using, handling, and storing oil and petroleum products.

For the model facilities with vertical ASTs, EPA developed several technically feasible approaches for installing liners and double bottoms. These approaches include:

- Retrofitting the bottom of an AST with a second steel plate (i.e., installing a double bottom), an interstitial geosynthetic liner on top of the original bottom, and a leak detection system (e.g., a tell-tale drain);
- Installing a liner within the secondary containment system around the AST;
- Installing a liner within the secondary containment system around the AST and retrofitting the bottom of the AST with a second steel plate, an interstitial geosynthetic liner, and leak detection system; and
- Installing a liner within the secondary containment system and installing an undertank liner with a leak detection system during construction of a new AST.

For horizontally mounted tanks, the only option considered was the installation of a liner throughout the entire secondary containment system. During development of these options, EPA considered a range of AST sizes and secondary containment systems, such as structures with pipe penetrations through side walls and those built to accommodate vehicle access.

EPA evaluated four types of liner materials – soil (e.g., clay), concrete, geomembranes, and steel – that could be integrated into secondary containment structures. All four liner materials provide roughly equivalent protection provided that they are properly installed and maintained. The cost of liners for secondary containment areas around ASTs varies significantly by material. Although steel and coated concrete liners were found to provide excellent protection and durability, these systems generally are considerably more expensive than soil or geomembrane liners.

Based on the technical feasibility and unit-cost analysis of different liner designs at model facilities, EPA determined that for large facilities it may be less expensive to install a complete liner system at a new facility than to retrofit an existing facility. Depending on the liner type, the cost to install a complete liner system at a new large bulk terminal can be 30 to 50 percent less than the cost to retrofit liners and double bottoms at an existing facility. For example, at a new large bulk petroleum terminal (with about 50 million gallons of storage capacity), a complete liner system is estimated to cost between $.03 and $.08 per gallon of storage capacity, or roughly between $1.5 million and $4 million.[5] In contrast, the cost to retrofit an existing large bulk terminal with a complete liner system is estimated to cost between $.07 to $.11 per gallon, or approximately $3.5 million to $5.5 million. However, for small end-user facilities, the retrofit costs at existing facilities may not be significantly different from installation costs at new facilities. For example, depending on the liner type, the estimated cost to install a liner system at an existing small end-user facility (with one horizontally mounted 2,000-gallon tank) ranges from $2.00 to $4.50 per gallon of storage capacity, or $4,000 to $9,000 on a facility basis, while the estimated liner costs for a *new* small end-user facility range from $1.50 to $4.00 per gallon of storage capacity, or $3,000 to $8,000.

The approaches presented above for installing liners and double bottoms at AST facilities essentially provide two types of protection in preventing leaking oil from reaching unprotected soil and ground water: protection underneath an AST and protection within the secondary containment area around the AST. For example, installing a liner only within the secondary containment area around the AST will prevent oil discharged from the tank into the secondary containment area (e.g., a leak from the side of the tank) from contaminating soil. However, this system will not detect discharged oil nor prevent oil from leaking through a corroded AST bottom and reaching soil, ground water, or surface water. Alternatively, installing a double bottom or undertank liner with a leak detection system beneath an AST will detect leaking oil and prevent oil from reaching soil, but will not prevent discharged oil that fills up an unlined secondary containment system from contaminating soil and possibly ground water. A key issue related to the effectiveness of liner systems is the extent to which liners are properly maintained. The relationship between liner effectiveness and maintenance, and the costs of that maintenance, can vary greatly depending on the purpose and nature of the liners and the inspection and maintenance requirements. Many AST facility owners and EPA personnel expressed concern that although certain types of liners require periodic maintenance to perform effectively, some facility owners may not currently allocate sufficient resources to liner maintenance activities.

[5] In general, the cost to install liner systems at facilities would be better represented in dollars per gallon of throughput rather than dollars per gallon of storage capacity since throughput is a more accurate measure of the economic value of the AST; however, EPA lacks sufficient data on average throughput to present costs on this basis.

RECOMMENDATIONS

The recommendation of this Report to Congress is based primarily on the results of EPA's study of liners as well as insights the Agency has gained over the past 20 years into the problems posed by onshore AST facilities. As a first step toward addressing the potential risks to public health and the environment as a result of contamination from AST facilities located near navigable waters, the Agency recommends initiating, through a *Federal Register* notice or stakeholder workgroups, a process involving broad public participation to develop a voluntary program. This process would give stakeholders the opportunity to share new or additional data and information to characterize the sources, causes, and extent of soil and ground-water contamination and efforts underway to address contamination at AST facilities nationwide. Such data are critical to determining the most appropriate and effective means to reduce contamination.

As envisioned by EPA, the voluntary program would be designed to encourage facility owners or operators, through incentives such as technical assistance, cost savings, and public recognition, to identify and report contamination, take actions to prevent leaks and spills, and remediate soil and ground-water contamination. This program would complement the Agency's efforts to develop cleaner, cheaper, and smarter approaches to environmental problems through innovative solutions that depart from the traditional regulatory approach. The Agency favors a voluntary, rather than regulatory, approach at this time in order to provide greater flexibility in addressing contamination at the vast range of oil storage facility types, sizes, and locations. A voluntary program could focus more directly on facilities that may pose the greatest hazard to public health and the environment. For example, the program may initially focus on larger, older facilities, and facilities located near waters, sensitive areas, or populations. In addition, a voluntary approach could allow implementation of the most appropriate prevention and cleanup activities for each facility. The program would look for incentives for industry to implement reasonable and cost-effective measures to address existing problems and help prevent future ones.

EPA views such a program as a cooperative effort among EPA, State governments, industry, and environmental groups. Based on this study's findings, EPA believes the program should include commitments from facilities to:

- Address known contamination and to assure that existing contamination will not be allowed to migrate offsite;
- Report to appropriate government agencies the status of facility contamination and actions underway to address any problems;
- Adopt the most protective appropriate prevention standards and upgrade equipment as necessary; and

- Monitor and/or implement leak detection to ensure that new leaks are addressed.

Provided stakeholders commit to the voluntary approach, a successful program will entail the identification of specific actions for participating facilities to undertake and include means for objectively measuring results.

EPA has evaluated the feasibility of conducting a voluntary program to address the problem of AST releases and concluded that a voluntary program is worth pursuing. Factors that support development of a voluntary program include: (1) the universe of large AST facilities is easily defined and represented by several large trade associations; (2) the voluntary program is consistent with the Agency's goal of developing and promoting innovative approaches to achieve environmental goals; (3) clear, achievable overall goals are apparent (i.e., to clean up contamination and prevent future releases); (4) flexible approaches are available to address the problem, thus allowing participants to implement the program in a tailored manner appropriate to their circumstances; (5) EPA is committed to providing technical assistance as well as other incentives; and (6) there are established industry and state practices and standards that can be used as a basis for constructing a comprehensive program.

In keeping with the Agency's initiatives to develop innovative, common-sense approaches to environmental problems, EPA supports a voluntary prevention and cleanup program as a first step in addressing the environmental problem presented by contamination from AST facilities. Industry representatives have expressed their support for such a program as a more cost-effective, flexible alternative than traditional regulation. EPA fully supports such an attempt, and believes it will be successful, provided that it has the full commitment of those involved. The Agency believes it is essential that stakeholders have the opportunity to participate in the development and execution of this voluntary program and will establish an open process for public input into the program's design and implementation.

1. INTRODUCTION

1.1 PURPOSE

Section 4113(a) of the Oil Pollution Act of 1990 (OPA) requires that: "The President shall conduct a study to determine whether liners or other secondary means of containment should be used to prevent leaking or to aid in leak detection at onshore facilities used for the bulk storage of oil and located near navigable waters." In Executive Order 12777, the President delegated authority to the U.S. Environmental Protection Agency (EPA) to conduct this study.

This report to Congress presents EPA's study to assess the extent to which liner systems should be used with ASTs at onshore facilities to detect leaks and/or prevent leaks from reaching soil, ground water, and surface water.[1] As part of this study, EPA investigated the nature and magnitude of leaking oil at onshore facilities with ASTs that are used for the bulk storage of oil. The Agency also assessed the technical feasibility of using liners and related systems to detect leaking oil, and to prevent leaking oil from contaminating soil and, by way of ground-water pathways, navigable waters. This report to Congress, which provides recommendations based on EPA's findings, fulfills Section 4113(a) of OPA.

1.2 BACKGROUND

Concerns about the environmental hazards posed by onshore oil-storage facilities have grown in recent years as a result of several widely publicized oil discharges from such facilities, including significant discharges from tank farms in Fairfax, Virginia, in 1990, and in Sparks, Nevada, in 1989. Such incidents have the potential to cause widespread damage, including contamination of soil, ground-water and surface-water supplies, loss of property, and risks to human health. Because several hundred thousand onshore facilities with ASTs are located throughout the U.S., many near sensitive environments (including ground water and surface water), discharges from ASTs represent a potentially significant environmental hazard.

Oil discharges may originate from many parts of an onshore AST facility, including tanks, loading/unloading areas where oil transfers are conducted between tank trucks or vessels and ASTs, and when oil is transported in underground and aboveground piping. Although liner systems could be installed at certain types of loading/unloading areas and other locations at a facility, EPA decided to focus on the feasibility of using liners and related systems to address oil leaking from ASTs to secondary containment systems and to soil underneath ASTs. This decision was made after consultations with Congressional

[1] For purposes of this study, "surface water" and "navigable water" are used interchangeably.

staff about the intent of OPA Section 4113(a). Although the problems posed by oil discharges at other parts of the facility (including leaks from underground piping) were not directly investigated during this study, EPA gained valuable insights into the nature of these problems.

For this study, EPA defined a liner as an engineered system that makes secondary containment structures more impervious. EPA assessed the feasibility of installing liners within secondary containment structures and under ASTs (i.e., undertank liners). EPA also assessed the feasibility of installing double bottoms on vertical ASTs as "other secondary means of containment," which could be used in place of undertank liners. Secondary containment liners used in conjunction with double bottoms or undertank liners are capable of addressing oil discharges from ASTs into secondary containment areas and to soil underneath vertical ASTs.

EPA evaluated the effectiveness of liner systems, including double bottoms, in reducing the potential for leaking oil to reach soil and surface waters via ground-water pathways.[2] Oil discharges to unlined secondary containment systems, such as episodic spills, and continuous leaks from the bottom of ASTs may contaminate soil and have the potential to migrate downward to ground water. Because ground water often is hydrologically connected to surface water, a ground-water oil plume has the potential to migrate and contaminate surface water. Furthermore, oil that repeatedly contaminates soil as a result of frequent spills may form subsurface oil plumes, which have the potential to contaminate surface water when precipitation migrates through soil to surface-water bodies. Based on these considerations, EPA assessed the suitability of using liner systems to protect navigable waters by evaluating the effectiveness of these systems in preventing discharged oil from contaminating soil and ground water.

For purposes of evaluating the technical feasibility of liner systems at onshore facilities, EPA included as a basis for this study the approximately 500,000 onshore facilities that meet the oil storage capacity threshold of the Oil Pollution Prevention regulation. These facilities have oil storage capacities ranging between several hundred gallons to several million gallons and are found in the majority of industry sectors. As a result, these facilities constitute a diverse and comprehensive group from which to evaluate the technical feasibility of installing liner systems.

1.3 STUDY APPROACH

EPA conducted two principal tasks in preparing this study:

Task 1: Gathered a range of data and information on leaks and spills from ASTs, types of liner systems, and their costs; and

[2] Throughout this study, "liner system" includes both secondary containment liners, undertank liners, and double bottoms.

Task 2: Conducted a technical feasibility analysis of liner systems for a range of typical onshore facilities with ASTs.

EPA gathered data on the number and type of onshore facilities storing oil in bulk, number and type of ASTs facilities and ASTs, and the number and volume of oil discharges from ASTs. EPA conducted interviews with facility owners and operators, manufacturers of liner systems, and Federal and State government personnel about the characteristics of liners systems, including their cost and effectiveness, as well as operation and maintenance requirements. This information was used to support the technical feasibility analysis.

EPA conducted a technical feasibility analysis of liner systems by examining the effectiveness of different liner materials and designs for protecting the environment from oil discharges and evaluating the construction feasibility of liner systems. The technical feasibility and unit-cost analysis is based on alternative liner designs for six "model" facilities used to represent the diverse universe of facilities that meet the oil storage capacity threshold of the Oil Pollution Prevention regulation. These model facilities ranged from small end-user facilities with one horizontally mounted 2,000-gallon AST to a large petroleum bulk terminal with a mix of horizontal and vertical ASTs with a combined storage capacity of about 50 million gallons. For these model facilities, the alternative designs considered and evaluations of their effectiveness were based largely on discussions with facility owner/operators, liner manufacturers, and government personnel.

Based on the results of these two tasks, EPA developed recommendations for minimizing the potential damage to the environment as a result of oil leaking from the nation's AST inventory.

1.4 ORGANIZATION OF REPORT

The remainder of this report is organized as follows:

- Chapter 2 provides background information on AST facilities nationwide and the general characteristics of ASTs, including oil discharges.
- Chapter 3 reviews Federal and State AST regulations and industry practices and standards, and provides estimates of the number of facilities already using liner systems.
- Chapter 4 describes the technical feasibility analysis of alternative liner system designs, and presents unit costs for facilities to install these liner systems.
- Chapter 5 presents EPA's recommendations.

In addition, appendices are included that provide supporting documentation for the various analyses discussed in the report.

2. BACKGROUND ON ASTs

This chapter provides information on AST facilities and ASTs and describes the potential environmental problems they pose. Specifically, Section 2.1 presents information on the number and type of U.S. facilities with ASTs and the general characteristics of ASTs nationwide. Section 2.2 describes the types of oil discharges from ASTs and the potential impacts on soil, ground water, and surface water. Section 2.3 presents information on the status of the U.S. AST inventory and the extent to which which oil discharges may be occurring at these ASTs.

2.1 PROFILE OF AST FACILITIES AND ASTs

EPA reviewed existing Agency reports, State information, and industry studies to develop a profile of the number and type of onshore facilities storing oil in bulk, and the number and type of ASTs. This information was used to:

- Analyze the types and characteristics of facilities with ASTs; and
- Develop representative facilities, or model facilities, to serve as the basis for developing technically feasible options for using liner systems with ASTs, and determining the corresponding facility costs.

This section provides information on the number and type of AST facilities and the number and general characteristics of ASTs.

2.1.1 Profile of AST Facilities

Section 4113(a) of OPA did not provide EPA with specific direction on the types of "onshore facilities used for the bulk storage of oil" that should be examined or the distance that qualifies a facility as being "located near navigable waters." As a result, EPA adopted a broad interpretation of this statutory language when preparing this report to avoid underestimating the number of ASTs that potentially benefit from using liners systems. Specifically, EPA used the storage capacity thresholds of the Oil Pollution Prevention regulation as the criteria to define the universe of facilities and ASTs that would be analyzed in the study because: (1) this regulation affects a diverse population of facilities from many industry sectors; and (2) the Agency previously conducted a study that provides estimates of the number and type of these facilities. These findings are discussed below.

EPA's "Spill Prevention, Control, and Countermeasures Facilities Study" (hereafter referred to as the *Facilities Study*)[3] provides estimates of the number of facilities that meet the storage capacity threshold of the Oil Pollution Prevention regulation because they have: (1) oil storage capacity greater than 42,000 gallons underground; (2) combined oil storage capacity greater than 1,320 gallons aboveground; or (3) greater than 660 gallons in a single tank aboveground. Exhibit 2-1 presents estimates of these facilities by Standard Industrial Classification (SIC) code category and three storage capacity tiers: 1,320 to 42,000 gallons; 42,001 to 1 million gallons; and greater than 1 million gallons. For purposes of this report, these facility storage capacity categories are referred to as small, medium, and large, respectively. EPA estimates that there are approximately 505,000 facilities that meet the storage capacity threshold of the Oil Pollution Prevention regulation. About 81 percent of these facilities are small, 18 percent are medium, and 1 percent are large.

This 505,000 estimate overstates the number of onshore facilities where AST liners systems could be installed because approximately 3,000 of these facilities are offshore oil production platforms that are currently regulated by the Department of the Interior's Minerals Management Service (MMS). Furthermore, not all of the remaining facilities are necessarily located near navigable waters. Specifically, EPA estimates that 435,000 of the 502,000 facilities (505,000 facilities minus 3,000 offshore production facilities) have the potential to discharge oil in harmful quantities into or upon the navigable waters of the U.S. or adjoining shorelines. Nevertheless, EPA elected to include facilities not located near navigable waters in this study because many of these facilities have the potential to contaminate surface water if they discharge oil to soil and ground water, which could be hydrologically connected to surface water.

As shown in Exhibit 2-1, facilities that meet the storage capacity threshold of the Oil Pollution Prevention regulation span many SIC code categories, and include facilities as diverse as farms, manufacturing facilities, and transportation facilities. Despite this industry diversity, these facilities may be grouped into three broad categories corresponding to how oil is used at these facilities. Specifically, oil is consumed or used as a raw material or end-use product (storage/consumption); marketed, refined, and distributed as a wholesale or retail good (storage/distribution); or pumped from the ground as part of oil exploration or production activities (production). Facilities in these three use categories have different characteristics in terms of basic physical and operating characteristics, such as the number and type of ASTs, throughput, and number and type of transfer points. For example, farms that use oil and diesel to heat buildings and power machinery are likely to have fewer ASTs and ancillary equipment and less product turnover than fuel oil dealers and bulk terminal facilities, which distribute petroleum

[3] U.S. EPA, Emergency Response Division, "Spill Prevention, Control, and Countermeasures Facilities Study," January 1991.

EXHIBIT 2-1

ESTIMATED NUMBER OF FACILITIES MEETING THE SPCC STORAGE CAPACITY THRESHOLDS

Facility Category	SIC (where applicable)	Oil Storage Capacity: 1,321 - 42,000 gallons (above ground only)	Oil Storage Capacity: 42,001 - 1,000,000 gallons	Oil Storage Capacity: >1,000,000 gallons	Total	"Best Estimate"
Farms	01/02	137,100 - 138,400	neg. - 1,300	0	137,100 - 139,700	138,400
Coal Mining/Nonmetallic Minerals Mining	12/14	2,500 - 4,500	500 - 900	neg. - 200	3,000 - 5,600	4,300
Oil Production[a]	131	118,000 - 233,000	41,000 - 82,000	neg.	159,000 - 315,000	237,000
Contract Construction	15/16/17	2,000 - 3,600	500 - 900	0	2,500 - 4,500	3,500
Manufacturing:						
Food and Kindred Products	20	3,000 - 3,500	600 - 700	100	3,700 - 4,300	4,000
Chemicals and Allied Products	28	3,000 - 5,500	600 - 1,100	neg. - 100	3,600 - 6,700	5,150
Petroleum Refining	29	1,000 - 1,200	800 - 900	300 - 400	2,100 - 2,500	2,300
Stone, Clay, Glass, and Concrete	32	1,000 - 8,500	200 - 1,700	neg. - 100	1,200 - 10,300	5,750
Primary Metal Industries	33	1,000 - 2,000	200 - 400	neg. - 400	1,200 - 2,800	2,000
Other Manufacturing[b]	20 - 39	4,000 - 8,000	800 - 1,600	100	4,900 - 9,700	7,300
Railroad Fueling	401	0	100 - 600	neg.- 100	100 - 700	400
Bus Transportation	411/413/414/417	1,200 - 1,600	300 - 400	0	1,500 - 2,000	1,750
Trucking and Warehousing/ Water Transportation Services	42/446	3,200 - 3,600	800 - 900	100	4,100 - 4,600	4,350
Air Transportation	458	0	500 - 600	neg.	500 - 600	550
Pipelines	46	0 - 400	neg. - 300	200 - 300	200 - 1,000	600
Electric Utility Plants	491	3,700	600	500	4,800	4,800
Petroleum Bulk Stations and Terminals	5171	1,400	8,800	2,200	12,400	12,400

EXHIBIT 2-1 (continued)

ESTIMATED NUMBER OF FACILITIES MEETING THE SPCC STORAGE CAPACITY THRESHOLDS

Facility Category	SIC (where applicable)	Oil Storage Capacity: 1,321 - 42,000 gallons (above ground only)	42,001 - 1,000,000 gallons	>1,000,000 gallons	Total	"Best Estimate"
Gasoline Service Stations	554	0	4,200 - 11,100	neg. - 100	4,200 - 11,200	7,700
Fuel Oil Dealers	5983	2,500 - 5,500	100 - 2,800	neg. - 300	2,600 - 8,600	5,600
Vehicle Rental	751	0	neg. - 300	0	neg. - 300	150
Commercial and Institutional:						
Health Care[c]	N/A	1,700 - 1,900	300 - 1,400	neg. - 200	2,000 - 3,500	2,750
Education[d]	N/A	4,900 - 5,000	100 - 800	neg. - 100	5,000 - 5,900	5,450
Military Installations	N/A	100 - 200	300	100 - 200	500 - 700	600
Other Commercial and Institutional	N/A	46,600 - 46,800	1,000 - 1,800	neg. - 200	47,600 - 48,800	48,200
TOTAL		337,900 - 478,300	62,300 - 122,200	3,600 - 5,700	403,800 - 606,200	
"BEST ESTIMATE"		408,100	92,250	4,650		505,000

Note: N/A means not applicable and neg. means negligible (i.e., less than 50). The "best estimate" is the midpoint of the range.

[a] This includes the 3,000 offshore facilities currently regulated by the Department of the Interior's Minerals Management Service (MMS).

[b] Other industrial manufacturing establishments in SICs 20 through 39, except SICs 20, 28, 29, 32, and 33.

[c] For the medium and large capacity tiers, data were available only for hospitals (SIC 806), which are included in the Health Care subcategory.

[d] For the medium and large capacity tiers, data were available only for colleges (SIC 822), which are included in the Education subcategory.

Source: U.S. Environmental Protection Agency, "Spill Prevention, Control, and Countermeasures Facilities Study," January 1991.

products to end-users. This characterization is important for developing model facilities, which provide the basis for developing technically feasible options for installing liners at these facilities.

The typical storage capacity of these facilities varies significantly, from several thousand gallons for farms and small industrial manufacturers to tens-of-millions gallons for petroleum bulk terminals. Similarly, the number of ASTs at these facilities varies considerably from one or two per facility to over 100 per facility. The model facilities discussed in Chapter 4 were developed to represent the range in storage capacity and number of ASTs at these facilities.

2.1.2 Profile of ASTs

In general, there are two categories of ASTs: vertical ASTs and horizontal ASTs. The storage capacity of horizontal ASTs typically ranges from a few hundred gallons up to 20,000 gallons, while the storage capacity of vertical ASTs typically ranges from several thousand gallons to over 10 million gallons. Vertical ASTs are mounted such that the tank bottom rests on a ground-level foundation, such as a concrete pad or ring wall. Small vertical tanks (e.g., less than 42,000 gallons), which are commonly used in the oil production industry, often are installed on a concrete pad, which, in addition to the tank bottom, may serve as a secondary barrier to prevent leaked oil from reaching soil and to aid in leak detection by channeling oil to the side of the tank where it may be visually detected.[4]

As the volume and the tank diameter of vertical ASTs increase, ring-wall foundations become more economical than concrete pads. Ring walls, normally made of reinforced concrete, provide a foundation or footing upon which the AST wall rests. The AST bottom plate typically rests on hard-packed soil, sand, or other fill material. Based on engineering experience, as ASTs reach 40,000 to 50,000 gallons of storage capacity, the combination of size and weight considerations are such that ring-wall foundations become more economical than concrete pads.[5] Unlike vertical tanks with concrete pads, leaks from the bottom side of vertical ASTs with ring walls have the potential to go undetected for extended periods of time before oil seeps to the edge of the AST, is detected during ground-water monitoring operations, or creates a sheen in a nearby stream or river.

Horizontal ASTs typically are supported in saddles that are bolted to secondary containment structures, such that tank is suspended above the ground or floor of a

[4] Concrete pads used with small ASTs often are manufactured with radial groves that aid in leak detection by channeling discharge oil to the side of the tank.

[5] An analysis of data provided by the *Entropy Study* (see footnote #9) generally confirms this experience. Specifically, for the oil production sector, approximately 88 percent of all ASTs with a storage capacity of less than 42,000 gallons are set on concrete pads.

secondary containment structure. Leaks from horizontal ASTs are generally easy to detect because facility personnel can readily see the underside of the tank.

The overwhelming majority of existing ASTs are fabricated using carbon steel, although stainless steel, reinforced concrete, and fiberglass materials also have been used for certain AST applications. The wall thickness of vertical ASTs may vary significantly, from 0.1875 inches for a 10,000-gallon AST to 1.135 inches for a 10 million-gallon tank. Similarly, the thickness of the annular bottom ring of a vertical AST may vary significantly. The bottom plates of a vertical AST must be constructed with a minimum thickness of 0.25 inches,[6] exclusive of any corrosion allowance specified by the purchaser, while the annular ring supporting the bottom-to-shell weld may be as thick as 0.75 inches for the larger ASTs. The thickness of the bottom is a critical factor in determining the potential for an AST to develop corrosion-related leaks (as discussed in Section 2.3.3). ASTs are either erected at the site (i.e., field erected) or are shop-fabricated by a manufacturer and then transported to the site. Virtually all ASTs with storage capacity greater than 50,000 gallons are field erected because of transportation constraints and construction considerations. Because the vast majority of ASTs are constructed with steel materials and, therefore, are susceptible to corrosion, these ASTs have the potential to leak oil.

EPA estimates that the number of ASTs at the 502,000 onshore facilities that meet the storage capacity threshold of the Oil Pollution Prevention regulation is about 1.8 million.[7,8] Based on the 1989 API "Aboveground Storage Tank Survey"[9] (hereafter referred to as the *Entropy Study*), about 700,000 ASTs are used at facilities in the production, refining, transportation and marketing sectors of the petroleum industry. These two estimates differ because the number of ASTs at all facilities that meet the storage capacity threshold of the Oil Pollution prevention include ASTs outside the petroleum industry, such as ASTs at end-user facilities (e.g., farms).

---

[6] When specified by the purchaser, a minimum nominal thickness of 6 millimeters for all bottom plates is acceptable.

[7] U.S. EPA, Emergency Response Division, "Estimate of the Number of Aboveground Storage Tanks at Onshore Facilities," October 1994.

[8] An alternative order-of-magnitude estimate was developed by multiplying the number of small, medium, and large facilities that meet the storage capacity threshold of the Oil Pollution Prevention regulation (presented in Exhibit 2-1) by the number of ASTs typically found at each of these facility size categories: two ASTs, seven ASTs and 17 ASTs for small, medium, and large facility categories, respectively. The estimates of the typical number of tanks was developed based on analysis conducted in support of revisions to the Oil Pollution Prevention regulation. Based on this approach, the number of ASTs are estimated to be about 1.5 million.

[9] American Petroleum Institute, "Aboveground Storage Tank Survey," prepared by Entropy Limited, April 1989 (hereafter referred to as the *Entropy Study*).

Exhibits 2-2 and 2-3 present data on the percentage distribution of ASTs by age and storage capacity, respectively. Exhibit 2-2 presents the distribution of ASTs by age for 700,000 tanks, which was obtained from the *Entropy Study*. About 32 percent of these ASTs are between 0 to 10 years old, while nearly 27 percent of these ASTs are between 11 to 20 years old. AST age may be a critical factor for determining the likelihood that leaks will develop as a result of corrosion (as discussed in Section 2.3.3).

Exhibit 2-3 shows the estimated distribution of ASTs by storage capacity (gallons) based on data provided by New York.[10] As shown in the exhibit, the largest proportion of ASTs have a storage capacity of between 1,000 and 10,000 gallons. This distribution is similar to the distribution of ASTs by storage capacity in the petroleum industry. Specifically, in Exhibit 2-4, AST distribution by storage capacity based on the New York State data is compared to similar data provided by the *Entropy Study*. As shown in the exhibit, both sources of data indicate that most ASTs are less than 21,000 gallons. This comparison suggests that the distribution of ASTs within the petroleum industry by storage capacity is similar to the overall distribution of ASTs by storage capacity – because the New York State data include ASTs from many industry sectors.

2.2 OIL DISCHARGES FROM ASTs

In general, AST oil discharges may be classified into two broad groups/categories: leaks and spills. These categories are useful for understanding how oil discharged from ASTs affects the environment and how different types of liner systems could aid in detecting discharges or preventing oil from contaminating surface water by way of tributary ground water.

Leaks typically originate from the bottom of vertical ASTs as a result of perforations in the bottom plates, which are often caused by corrosion. Leaks also may originate from the sidewalls of vertical ASTs, as well as any point on the surface of a horizontal AST. However, such leaks can be detected visually as part of a periodic tank inspection program and, therefore, may be addressed before significant contamination occurs. Although the amount of oil discharged per hour (or day) from ASTs as a result of leaks can be relatively small compared to spills (e.g., a leak rate of one gallon per hour versus a spill of hundreds or thousands of gallons), substantial volumes of oil may be discharged to soil underneath an AST over time because leaks may continue undetected for years. Leaked oil is commonly carried through the soil layer by precipitation and migrates downward to ground water. In addition, leaked oil may migrate horizontally to the edge of the AST bottom where it can be visually detected.

[10] Under New York State's Environmental Conservation Law, both existing and new facilities with a combined aboveground and underground storage capacity exceeding 1,100 gallons are required to register with the State in order to operate. Facilities are required to provide general facility information and detailed tank-specific information, including the storage capacity of ASTs, to the New York State Department of Environmental Conservation (NYDEC) by filling out an application form. This information is entered into a computer data base, which is maintained by the NYDEC.

EXHIBIT 2-2

DISTRIBUTION OF ASTS BY AGE CATEGORY

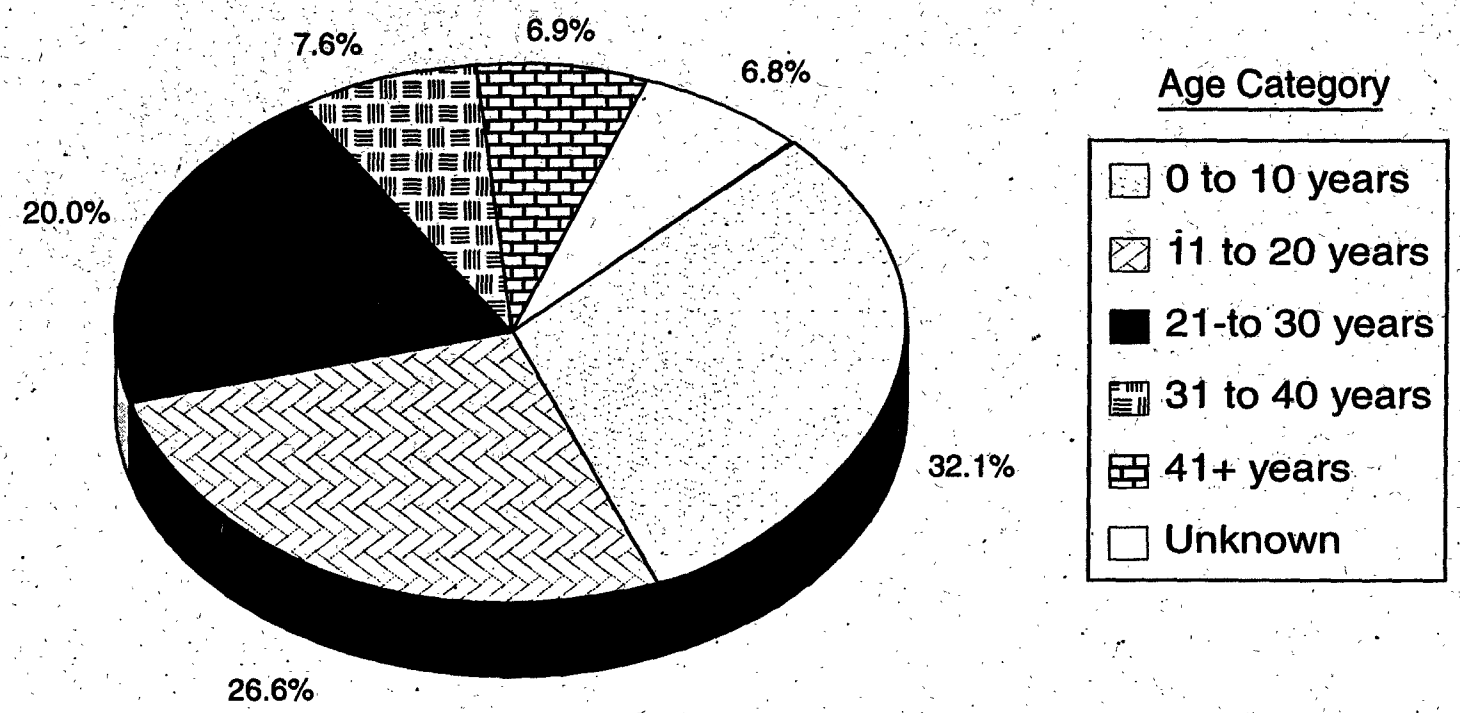


EXHIBIT 2-3

DISTRIBUTION OF ASTs BY STORAGE CAPACITY TIER

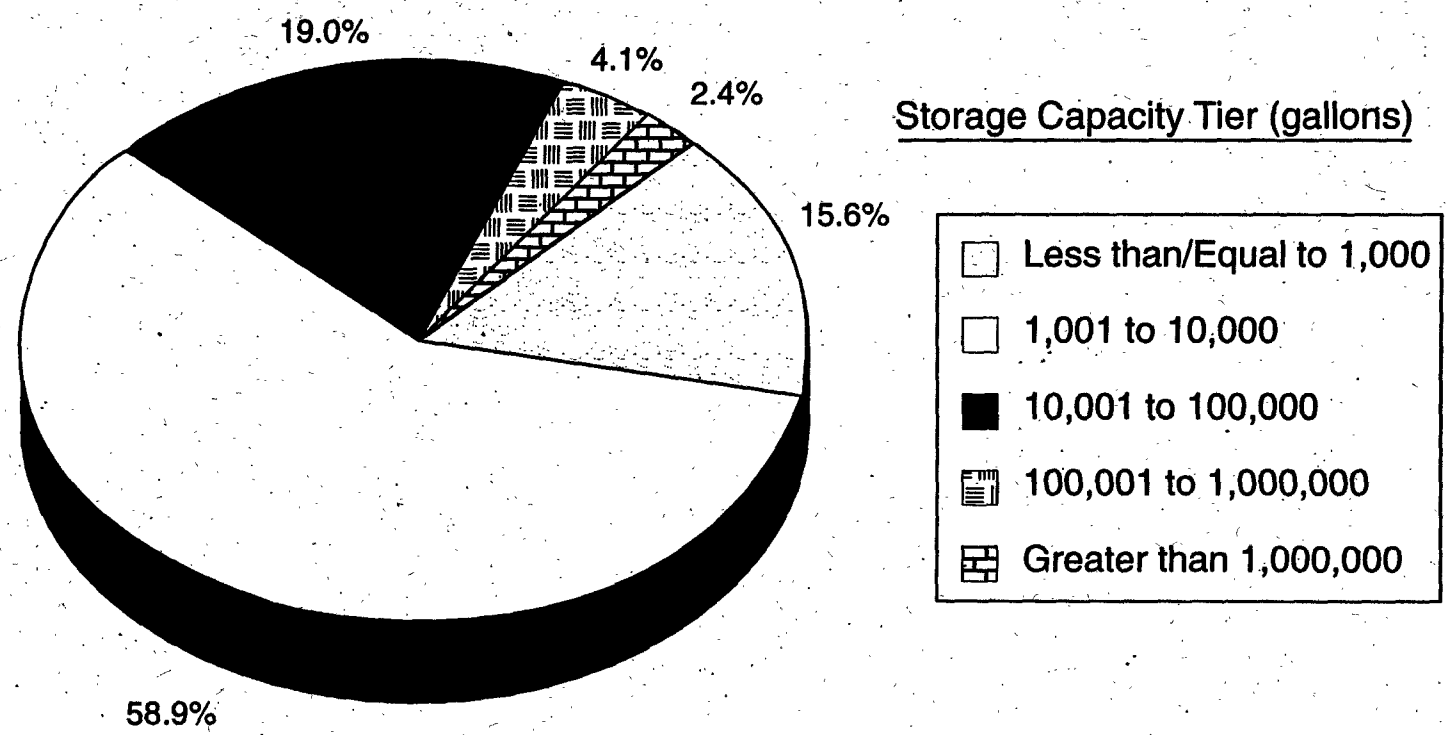


EXHIBIT 2-4
DISTRIBUTION OF ASTs BY STORAGE CAPACITY BY DATA SOURCE

SOURCE OF DATA	AST STORAGE CAPACITY TIER (Gallons)				
	less than or equal to 21,000	21,001 to 42,000	42,001 to 420,000	420,001 to 4,200,000	greater than 4,200,000
New York State	90.7%	2.1%	3.1%	3.6%	0.5%
API/Entropy Study	82.8%	6.4%	6.0%	4.2%	0.6%

Spills are episodic events, whereby potentially significant quantities of oil may be discharged rapidly into secondary containment areas and beyond. Spills from ASTs may occur as a result of operator error, for example, during loading operations (e.g., vessel or tank truck - AST transfer operation), or as a result of structural failure (e.g., brittle fracture) because of inadequate maintenance of the AST. Oil discharged from spills may fill up secondary containment structures (e.g., diked areas) that surround ASTs and, if the secondary containment system is unlined, migrate through soil and ground water to surface water. A range of secondary containment liner systems to address the potential problems posed by oil spilled into secondary containment areas is discussed in Chapter 4.

Oil discharged from ASTs as a result of either spills or leaks has the potential to contaminate the environment. Oil spills from ASTs may adversely affect soil, ground water, surface water, ecosystems, and organisms. Spilled oil can move over the ground or through the soil and can be carried along by precipitation. Precipitation that falls on the land surface enters into a number of different pathways of the hydrologic cycle. Some of the water will drain across the land directly into a stream channel, while some will seep through the soil and become ground water. Ground water flows through the rock and soil layers of the earth until it too discharges as a spring or as a seepage into a stream, lake, or ocean. Soil contamination (e.g., oil spilled onto the ground from an AST) may therefore be carried down into the ground water by precipitation, and this contamination may then be discharged into surface water. Such a scenario is specifically contemplated in EPA's underground storage tank (UST) technical requirements at 40 CFR part 280. Under the UST regulation, a suspected tank leak must be reported if released petroleum is discovered at the site or in the surrounding area (such as the presence of free product or vapors in soils, basements, sewer and utility piping, and nearby surface water).

A great deal of research has already been conducted on the effects of oil on the environment. Spilled and leaked oil can damage farmland and adversely affect water supplies by polluting wells or water intakes on surface streams. Soil contamination also may threaten aquatic or terrestrial wildlife and may contribute to pollution in lakes, rivers, freshwater wetlands, estuaries, beaches, and ocean waters (where runoff is a major

source of oil pollution). Oil in sewers, pipeline trenches, or foundation fills can increase the risk of fire and explosion. In addition, lethal effects of oil on organisms may include bird mortality caused by oiled feathers, fish mortality, and egg or larval stage losses. Sublethal effects of AST oil spills on aquatic organisms could include stress-related disease and disruption in behavior patterns or reproduction.

Various technologies are available to remediate oil-contaminated soil, although use of these technologies can present site-specific difficulties. For example, incineration has been demonstrated to achieve remediation cleanup goals, but is relatively costly and may not be acceptable to the public. Surface-enhanced bioremediation, on the other hand, is not feasible at all sites; the hydrogeology of the site must not allow for rapid transport of the contaminants to the ground water, and the soil must be compatible with the introduction of nutrients.

Similarly, there are various remediation options to handle oil-contaminated ground water. Most of these options are either containment technologies (e.g., slurry walls) or some variation of the traditional "pump-and-treat" approach. Ground-water pump-and-treat systems can be very costly, and treatment goals may take 30 years or longer to achieve. It should also be noted that for certain stratigraphies (e.g., fractured bedrock or karst topographies), restoration of contaminated aquifers may not be achievable or feasible with existing technologies.

Exhibit 2-5 highlights three case studies illustrating the problems posed by AST facilities and concerns regarding the potential for oil to contaminate soil, ground water, and surface water.

2.3 STATUS OF ASTs NATIONWIDE

EPA conducted an extensive data collection effort to estimate the number of leaking ASTs. Specifically, the Agency investigated Federal government data bases, such as the Emergency Response Notification System (ERNS), and contacted several States about data on AST leaks. The Agency found that comprehensive data do not exist to quantify adequately the extent to which the nation's AST inventory is leaking. Existing Federal regulations require facility owners and operators to report oil discharges that reach navigable waters and thereby trigger the reporting thresholds of Clean Water Act (CWA) regulations. Consequently, AST oil discharges that affect only soil and ground water and that do not initially reach surface water are generally not reported. Despite these limitations, existing data sources evaluated by EPA suggest that a significant number of ASTs may be leaking or spilling oil.

Section 2.3.1 discusses EPA's review of Federal reporting requirements related to oil discharges. Section 2.3.2 describes the available information on the extent to which ASTs are leaking oil. Section 2.3.3 provides an age profile of the AST universe and examines the potential relationship between leak probability and tank age.

EXHIBIT 2-5
CASE STUDIES

Case Study #1:
COLDBROOK ENERGY FACILITY

On April 17, 1993, about 35,000 gallons of gasoline spilled from a 6-inch crack in an AST at the Coldbrook Energy Facility in Hampden, Maine. The tank was surrounded by an unlined containment dike that contained the spilled material. Remediation measures employed at the site included recovery wells and trenches dug into the contaminated soil. Response crews also deployed sorbent boom along the banks of the nearby Penobscot River as a precautionary measure. Fortunately, only small amounts leached into the river during periods of low tide, producing a light sheen ("World Spill Briefs," *Golub's Oil Pollution Bulletin*, Vol. 5 No. 12, May 1993, p. 7).

Case Study #2:
STAR TANK FARM

At the Star Enterprise Inc. tank farm in Fairfax, Virginia, more than 150,000 gallons of oil is sitting on ground water beneath the Star site and a neighboring community. The site was first investigated in September 1990, after migration of the underground plume produced a light sheen on a nearby creek. Officials at Star Enterprise acknowledge that a missing overflow container at the loading area of the tank farm could have allowed thousands of gallons of oil to seep into the soil and ground water undetected; it is not clear whether this is the only source of petroleum discharges at the site, and investigations are continuing.

Case Study #3:
SPARKS BULK FUEL TANK FARM

An example of a larger petroleum spill to land affecting soil and, subsequently, ground water occurred at a bulk fuel tank farm in Sparks, Nevada. In 1989, a 3- to 5-million-gallon petroleum plume was discovered extending a mile east of the facility into a gravel pit. The oil from the plume appeared to be seeping through the gravel pit walls and collecting into a water pool in the bottom of the pit. The gravel company that owned the gravel pit pumped the solution out of the pit and into containment ponds for treatment. The pumping action drew the area ground water down to the pit bottom, diverting it from its natural flow south into the Truckee River. Regulators said that if the pumping were to stop, the contaminated ground water would continue downstream and end up in the river.

2.3.1 Federal Reporting Requirements

The Hazardous Materials Transportation Act (HMTA), as amended, the CWA, the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA), and the Resource Conservation and Recovery Act (RCRA) all contain requirements for reporting releases of hazardous materials to the environment under certain conditions. For oil discharges, however, these reporting requirements are not inclusive because releases from ASTs to land that do not directly affect surface water or that are not related to transportation are generally not covered.

The U.S. Department of Transportation (DOT) maintains several systems for reporting transportation-related hazardous material. Under the HMTA, as amended, DOT collects information on releases of hazardous materials, including oil products, during transport by highway, rail, pipeline, water, or air. In some circumstances, information regarding spills from ASTs may be included in DOT's systems (e.g., an oil release from a tank connected to a pipeline). Many AST discharges, however, are not transportation-related.

The oil discharge regulations promulgated at 40 CFR part 110 and 33 CFR part 153 under the CWA require that an oil discharge to U.S. waters or adjoining shorelines, or in ocean waters out to approximately 200 miles from the shore, must be reported immediately to the National Response Center (NRC) if it meets one of the following three conditions:

- Causes a sheen to appear on the surface of the water;
- Violates applicable water quality standards; or
- Causes a sludge or emulsion to be deposited beneath the surface of the water or upon the adjoining shorelines.

Traditionally, the CWA reporting requirements have not been interpreted to encompass oil discharges to soil that reach ground water, but do not migrate to surface water.

In contrast, CERCLA does require that releases of hazardous substances to land and ground water be reported to the NRC. However, CERCLA's list of regulated substances excludes petroleum products unless they are specifically listed. In general, crude oil and refined petroleum products are not listed under CERCLA. Both CWA discharges and CERCLA releases reported to the NRC or EPA are contained in ERNS.

Finally, the RCRA Subtitle I requirements cover petroleum releases to land, but only if they originate from an UST system. The Federal UST regulations (at 40 CFR part 280) implement Subtitle I. Such underground storage systems are broadly defined to include tanks (together with underground piping) that have a volume that is 10 percent or more beneath the ground surface. UST owners and operators must report suspected

releases of any volume of petroleum to the environment, as well as spills or overfills that exceed 25 gallons (or other amount specified by the implementing agency). ASTs would be covered only if they fit within the UST definition, and release reports would be maintained by the implementing agency (usually a State agency).

Based on these considerations, EPA believes that shortcomings exist with regard to requirements for the reporting of discharges of oil from ASTs that initially only affect soil and ground water, and that further action may be warranted to address this issue.

2.3.2 Discharges from ASTs

EPA analyzed ERNS data to estimate the number of reported oil discharges that occur from ASTs annually. The ERNS data base is the Federal government's central source of data on reported discharges of oil and hazardous substances. The oil spill data contained in ERNS include information collected primarily from initial release notifications received by the NRC, U.S. Coast Guard, and EPA. ERNS data indicate that roughly 30 percent of reported oil discharges from facilities are to secondary containment areas. This discharged oil could be addressed by liner systems installed within secondary containment systems.

Of the States that EPA contacted, only Virginia provided detailed information on oil discharges from AST facilities. The Virginia Department of Environmental Quality (VADEQ) recently implemented a regulatory program that requires certain AST facilities to: (1) register all applicable ASTs with VADEQ; (2) satisfy financial responsibility requirements; (3) submit an Oil Discharge Contingency Plan (ODCP); and (4) participate in the AST pollution prevention program. In particular, under the ODCP requirements, facilities with an aggregate oil storage capacity of greater than 1 million gallons must submit a Ground Water Characterization Study (GCS).[11] This study requires facilities to monitor ground water for signs of oil contamination. Based on GCSs submitted by 88 facilities to VADEQ as of April 4, 1994, about 88 percent of facilities (77 facilities) reported ground-water contamination. The data were not sufficient to determine whether this contamination is the result of past practices or is continuing to occur at these facilities.

API conducted a survey in 1994 to determine the extent to which member facilities in the refining, marketing, and transportation sectors of the petroleum industry have ground-water contamination.[12] About 300 facilities, or 85 percent, of 350 API member facilities completed the survey. The results of the survey indicate that 85

[11] Virginia Regulation 680-14-12: Facility and AST Registration Requirements, effective September 22, 1993.

[12] American Petroleum Institute, "A Survey of API Members' Aboveground Storage Tank Facilities," prepared by API Health and Environmental Affairs Department, July 1994.

percent of refineries, 68 percent of marketing facilities, and 10 percent of transportation facilities have known ground-water contamination near their facilities. Furthermore, the majority of these facilities are remediating the contaminated ground water. According to API, the results of this survey may be extrapolated to all API member facilities. Again, it is not clear from these data whether this contamination is continuing to occur at these facilities. However, API reports that improved equipment and operating practices over the last 5 years have reduced reported petroleum spills and accidental releases. These improvements include:

- In 1991, API published standard 653 as guidance for establishing inspection intervals for AST bottoms. This standard also "incorporates an AST inspector certification program that establishes minimum education and experience qualifications and provides for the testing of candidates."

- Guidance on the development of an overfill prevention program is provided in API Recommended Practice 2350.

- Systems and operating procedures to remove, recover, or properly handle tank water-bottoms have been or are being implemented at storage facilities.

- Survey results indicate the use of cathodic protection for buried AST-associated piping has increased.

2.3.3 Age Profile of ASTs

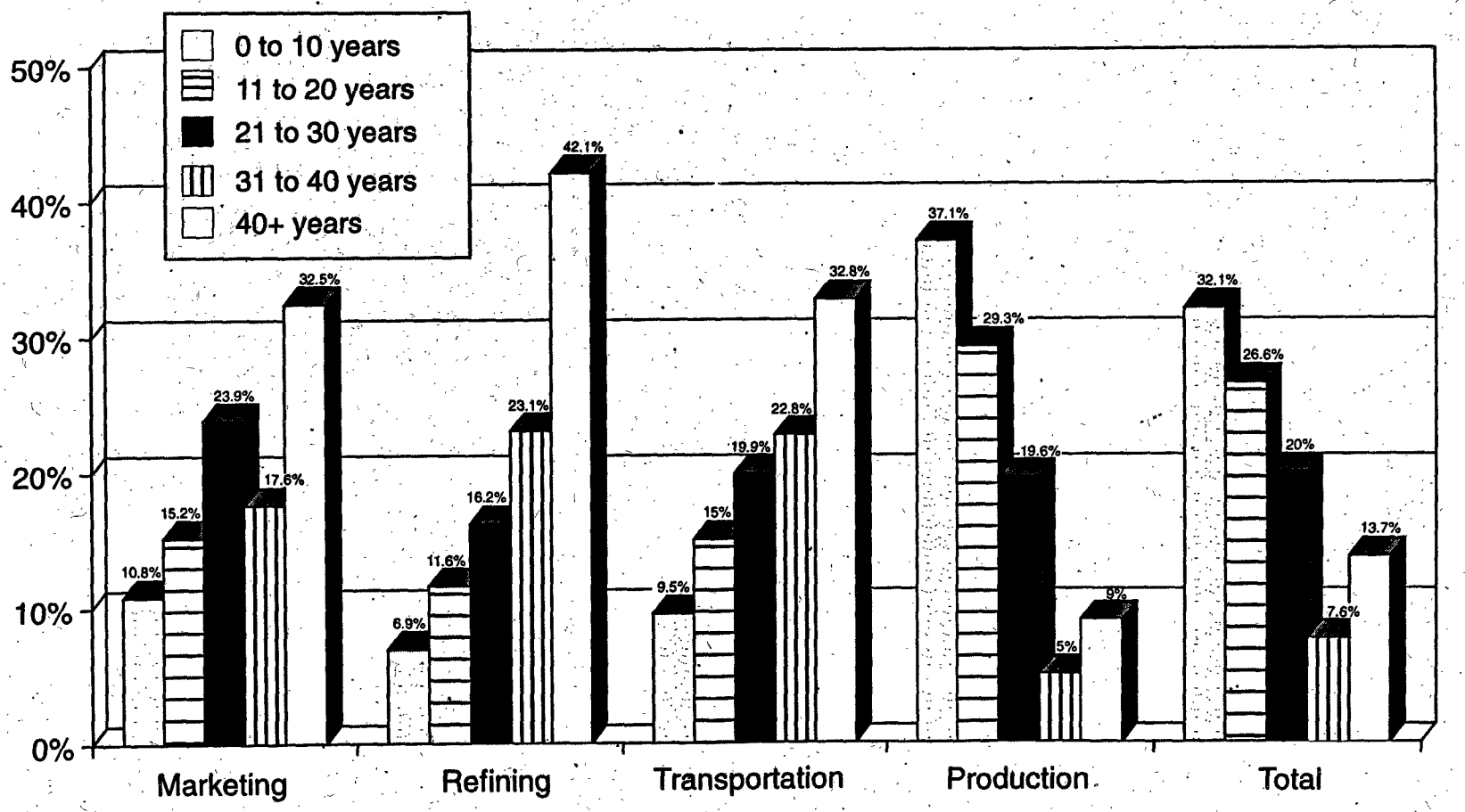
EPA obtained data on AST age and examined the potential relationship between AST age and corrosion rates to estimate the likelihood that ASTs will develop leaks as a function of tank age.

The most comprehensive data currently available on the age of ASTs are provided by the *Entropy Study*. This study provides estimates of the number of ASTs by several age categories for each industry sector. These data are shown in Exhibit 2-6. As shown in the exhibit, the distribution of ASTs by age category is roughly similar for the marketing, refining, and transportation sectors, in that the majority of ASTs within each of these sectors are over 40 years old. However, in the oil production sector, most ASTs are less than or equal to 10 years of age. Because the number of ASTs in the production sector is significantly greater than the number of ASTs in the other sectors, the overall age distribution for ASTs in the petroleum industry is similar to the age distribution for ASTs in the production sector.[13]

[13] Specifically, the number of tanks in the production, marketing, refining, transportation, sectors is estimated by the *Entropy Study* to be 572,620, 88,529, 29,727, and 9,197, respectively, for a total of 700,073. About 82 percent of all ASTs are in the production sector.

EXHIBIT 2-6

PERCENTAGE OF ASTS BY AGE CATEGORY



Source: *Entropy Study*

EPA investigated the potential relationship between the age of ASTs and failure rates based on data provided in a study conducted by the Suffolk County Department of Health Services in 1988 entitled, "Final Report, Tank Corrosion Study" (hereafter referred to as the *Suffolk County Study*). During the 1980s, Suffolk County, New York, enacted legislation that required all unprotected bare steel USTs to be replaced with protected storage tanks by 1990 – whether or not there was evidence that the USTs were leaking oil. As a result, this program provided a valuable sample of data to estimate leak probabilities as a function of age because leaking USTs were included in the sample along with perfectly functional USTs.

Hundreds of USTs were inspected as part of this program to determine the extent to which corrosion caused leaks. A relationship between UST tank age and the probability that USTs will develop a leak caused by corrosion was identified.[14] Specifically, the original design wall thickness appears to be a key factor influencing the amount of time a bare steel tank will remain free of perforations. USTs with thicker walls normally will take longer to develop a perforation due to corrosion than USTs with thinner walls, all other factors being equal (e.g., the acidity of the soil). Because the rate at which tank walls fail due to corrosion is related to tank age, the age of the tank may be used as an indicator to predict the likelihood that tank walls will develop perforations. Exhibit 2-7 presents the percentage of USTs that would fail due to corrosion by age category, based on estimates from the results of the *Suffolk County Study*.

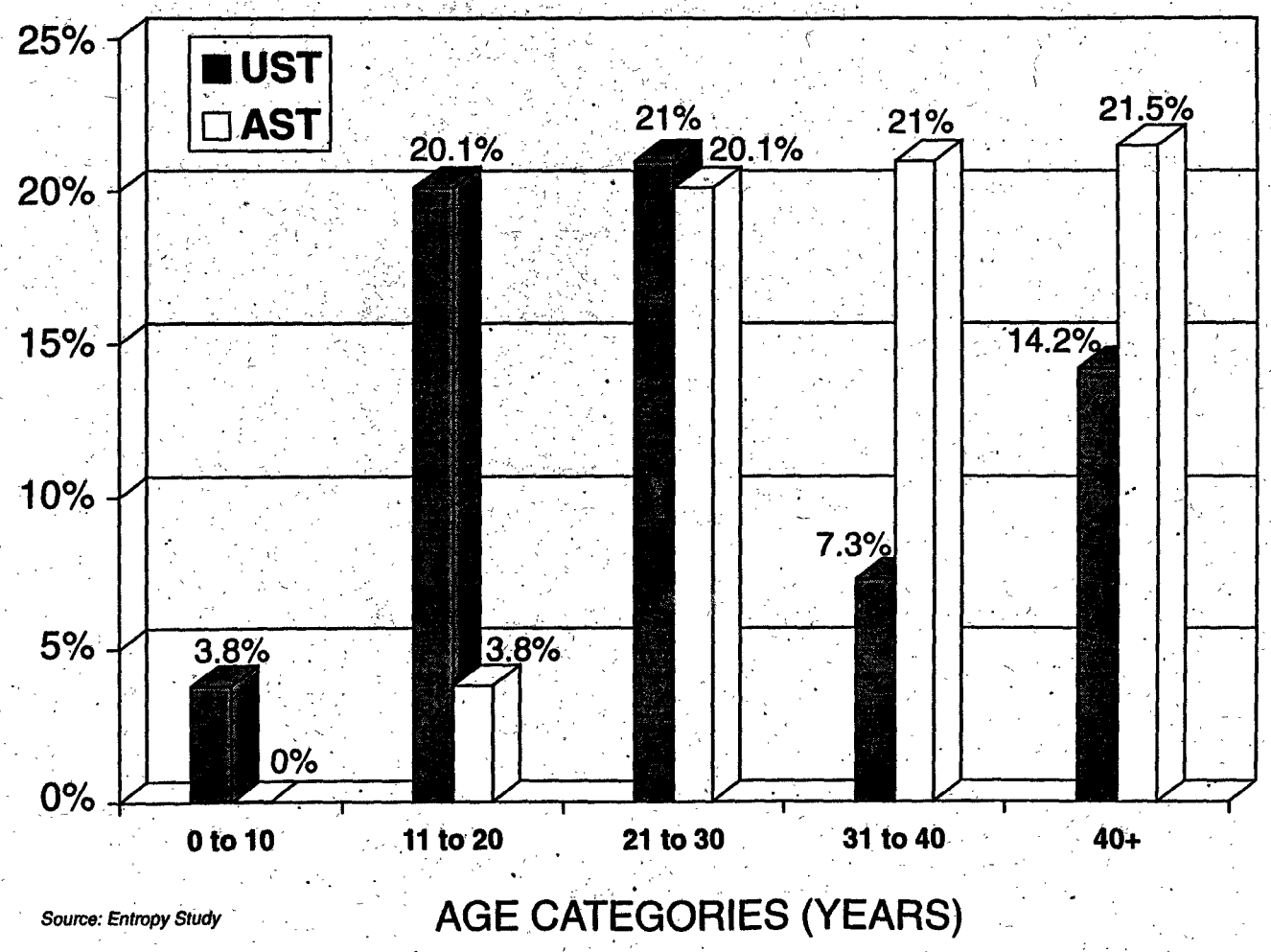
In extrapolating the results of the *Suffolk County Study* to ASTs, EPA modified some of the assumptions regarding the relationship between the tank age and the probability of leaks because of the differences between the nominal wall thickness of USTs and the nominal thickness of AST bottoms. Specifically, ASTs are generally constructed using thicker bottoms than are USTs walls as a result of structural considerations and industry standards. Based on these considerations, EPA assumed that, on average, ASTs fail as a result of corrosion 10 years later than USTs. This 10-year estimate was based on the added nominal bottom thickness for ASTs as specified in current industry standards. Exhibit 2-7 presents EPA's estimates of the percentage of ASTs that fail due to corrosion by age category.

As shown in the exhibit, ASTs less than 10 years old are assumed not to fail as a result of corrosion. AST failure due to bottom corrosion is generally greatest for tanks older than 40 years. Specifically, the likelihood of a corrosion-related failure of the tank bottom for ASTs in this age category is estimated to be about 22 percent.

[14] Other factors that may affect the likelihood of corrosion-related tank failure include: (1) acidity of the soils; (2) height of the water table; and (3) the presence of tank design features such as baffles or deflection plates.

EXHIBIT 2-7

PERCENT CORROSION FAILURE IN EACH AGE GROUP



Source: Entropy Study

The probability rates for corrosion-related failure of ASTs estimated here do not consider the effects of using cathodic protection systems to retard corrosion of the bottom plate of vertical ASTs. Specifically, cathodic protection systems have the potential to reduce the rate at which the bottoms of ASTs corrode if these systems are properly maintained. EPA did not adjust the probability estimates as a result of cathodic protection because data on the use of cathodic protection systems with ASTs are incomplete and cathodic protection is effective only if it is properly maintained.

3. EXISTING REGULATIONS AND INDUSTRY PRACTICES FOR LINER SYSTEMS

EPA reviewed Federal and State regulations and industry practices to gather information on the specifications of liner systems and to estimate the number of AST facilities currently required to use liners. Section 3.1 discusses the results of EPA's review of Federal and State AST regulations. Section 3.2 summarizes recommended industry practices related to AST liners and double bottoms. Section 3.3 presents EPA's estimate of the number and type of facilities required to use liner systems as a result of State regulations.

3.1 REVIEW OF FEDERAL AND STATE AST REGULATIONS

3.1.1 Federal Regulations

In general, existing Federal regulations affecting AST facilities do not explicitly require the use of liners or double bottoms with ASTs. However, section 112.7(c) of the Oil Pollution Prevention regulation, which is the primary Federal regulation addressing oil discharge control and response equipment and procedures for AST facilities, requires that "appropriate containment and/or diversionary structures or equipment to prevent discharged oil from reaching a navigable water course should be provided" and that such containment be "...sufficiently impervious to contain spilled oil." This regulatory requirement could be met by constructing a secondary containment system, such as a dike, with materials that have a low permeability (i.e., resist the penetration of oil through the material) or by adding a liner to the secondary containment system to provide this protection. However, this requirement does not specify a permeability standard, such as how far oil may move through the material per unit time (e.g., 1 millionth of a centimeter per second). Although EPA does not have comprehensive data on the quality of secondary containment structures at AST facilities nationwide, information provided by EPA field personnel indicates that the quality of secondary containment systems (e.g., the permeability of the materials) varies considerably.

The Federal UST regulation under RCRA Subtitle I (at 40 CFR part 280) and the Federal Hazardous Waste Storage Tank (HWST) regulation under RCRA Subtitle C (at 40 CFR part 264) require that facility owners and operators consider the installation of liners as a protective option for USTs and HWSTs. Although the Federal UST and HWST regulations do not specify liner materials or designs, these regulations establish performance criteria for containment materials and structures. For example, the UST regulation mandates a permeability for liners of 1×10^{-6} centimeters per second (cm/sec). The HWST regulation requires that external liner systems be capable of preventing lateral and vertical migration of the waste if a release from the tank(s) should occur.

Leak detection practices or devices are required by the UST and HWST regulations. The UST regulation specifies that leak detection equipment must be able to detect a 0.2 gallon-per-hour leak and that tanks must be inspected monthly. The HWST regulation requires that leak detection systems be in continuous operation and be capable of detecting a release within 24 hours or at the earliest practicable time.

In general, ASTs (and associated piping) that have less than 10 percent of their volume below the ground surface are not subject to the Federal UST regulations. The HWST regulations affect only ASTs that contain hazardous wastes. Thus, Federal regulations do not require facilities with ASTs containing oil to have liner systems within secondary containment systems.

3.1.2 State Regulations

EPA conducted a review of current and proposed AST regulations for the 50 States to gather information on liner requirements and specifications and to determine quantitatively the extent to which States require facilities to have liner systems. The results of this review of regulations for each State is briefly summarized in Appendix A.

EPA identified nine States that have promulgated or have proposed regulations that specify the use of "impermeable" secondary containment systems, liners, or other diversionary structures and systems to prevent discharges of oil from reaching soil, ground water, or surface water: Alaska, Connecticut, Florida, Maryland, New Jersey, New York, Rhode Island, South Dakota, and Wisconsin.[13] For each of these States, the following information is provided below and summarized in Exhibit 3-1:

- The applicability of the requirements to different sizes and/or types of facilities; and
- Specifications that address secondary containment (including liner specifications) and leak detection procedures and/or equipment.

Alaska (18 ACC 75): Alaska requires that all new and existing crude oil storage facilities with a total storage capacity of more than 5,000 barrels (and non-crude facilities with a storage capacity of more than 10,000 barrels) locate their tanks within a "sufficiently impermeable" secondary containment area. Secondary containment *under* tanks at new installations must include "impermeable" liners or double bottoms. Liner and permeability specifications apply to new facilities and new secondary containment areas only:

[13] Connecticut's regulations were proposed at the time of this review.

EXHIBIT 3-1

SUMMARY OF STATE REGULATORY REVIEW FOR THE NINE STATES

REGULATION	SECONDARY CONTAINMENT LINERS	UNDERTANK LINERS	LINER MATERIALS	PERMEABILITY RATE (CM/SEC)	LEAK DETECTION WITH LINERS[a]
Alaska	✓	✓	✓ [b]	1×10^{-7} [b]	✓
Connecticut (proposed)	✓	N/A	N/A	1×10^{-5}	✓
Florida	✓	✓	✓	1×10^{-7}	–
Maryland	✓	N/A	N/A	1×10^{-4}	–
New Jersey	✓	✓	✓	1×10^{-7}	–
New York	✓	✓	✓	1×10^{-6}	✓
Rhode Island	✓	✓	✓	1×10^{-6}	–
South Dakota	✓	✓	✓	1×10^{-6}	✓
Wisconsin	✓	✓	✓	N/A	N/A

Notes:

✓ Regulations require these specific provisions

N/A Not applicable; these provisions are not part of the regulation

a/ States indicated by a "–" require visual detection. States indicated by ✓ also require additional measures such as inventory control or automatic leak detection equipment.

b/ New facilities are required to have a liner that has a permeability of 1×10^{-7} cm/sec (layer of manufactured material in the area under the tank) or 1×10^{-6} cm/sec (layer of natural or manufactured material) for new secondary containment structures, excluding undertank applications

- "Sufficiently impermeable" for new installations consists of a "layer of natural or manufactured material of sufficient thickness, density, and composition to produce a maximum permeability for the substance being contained of 1×10^{-6} cm/sec."

- "Impermeable" liners for new installations consist of a "layer of manufactured material of sufficient thickness, density, and composition to produce a maximum permeability for the substance being contained of 1×10^{-7} cm/sec."

Alaska requires that each tank at new and existing installations must be equipped with a leak detection system that can be used externally to "detect leaks in the bottom of the

tank, such as secondary catchment under the tank bottom with a leak detection sump, a sensitive gauging system, or another leak detection system approved by the department." The owner or operator must check for the presence of leaks or spills daily at a staffed facility and at least once a month at an unstaffed facility.

Connecticut (RSCA proposed 22a 449): The proposed regulations would require facilities with aggregate storage of more than 1,320 gallons, or that have a single tank of more than 660 gallons, to have secondary containment in the form of "impermeable... dikes" around all tanks. These volume specifications are consistent with the Federal Oil Pollution Prevention regulation. These regulations would apply equally to both new and existing facilities.

- Dike permeability must be less than 1×10^{-5} cm/sec. The dikes may be either above or below grade, but the depth of a dike may not exceed 10 feet below the outside finished grade. The diked area must contain at least 100 percent of the volume of the largest enclosed tank.

Proposed leak detection specifications, like those for most of the eight other States, will require regular visual inspections around tanks and transfer piping. Connecticut also proposes to mandate weekly inventory measurement/record reconciliation procedures to detect slow leaks that have the potential to escape visual checks.

Florida (FAC 17-762): Florida law specifies "impervious secondary containment" systems. The regulations apply to all new facilities with a storage capacity of greater than 550 gallons. All existing facilities with a storage capacity of greater than 550 gallons must comply with the regulations by the year 2000, except for certain shop-fabricated tank systems.[14]

- The liner systems may be synthetic, concrete, or clay-based, and they must be capable of containing 110 percent of the largest tank enclosed by the secondary containment area, unless that tank is itself enclosed in a concrete vault, or is double walled.

- The definition of "impervious" varies depending on the liner material used. For synthetic systems, it is 1×10^{-7} cm/sec. Concrete liners must only be "product tight." Clay-based liner systems must be individually approved by the Florida Department of Environmental Protection.

[14] Vehicular fuel-storing shop-fabricated systems that store or use 1,000 gallons or less per month or 10,000 gallons or less per year also must comply with these regulations by the year 2000. Other aboveground shop-fabricated tanks may be retrofitted with double bottoms rather than an undertank impermeable liner. All alterations must be installed to regulatory specifications by the year 2000.

Specified leak detection measures consist of visual inspections or other appropriate measures. Inspections should be conducted around "tanks and integral piping," and must be conducted at least once per month.

Maryland (CMR 26:12): Maryland law specifies that secondary containment must be "capable of effectively holding the total volume of the largest storage container located within the area enclosed by the dike or wall." The regulations apply to new and existing facilities with a total storage capacity of greater than or equal to 10,000 gallons. Facilities with a storage capacity of less than 10,000 gallons, if judged to be a reasonable threat to State waters, also are subject to the regulations. The regulations prohibit the construction of tanks, dikes, or walls in wetlands or 100-year floodplains, unless a permit is obtained.

- Liner materials are not specified, nor are any designs except that the system must consist of continuous dikes or walls.
- The permeability of the system must be 1×10^{-4} cm/sec or less, for an unspecified liquid. Provisions for storm water collection/release are not specified.

Maryland requires visual inspections for leak detection. Areas to be included in each inspection are "seams, rivets, nozzle connections, valves, pumps, and pipelines directly connected to aboveground storage tanks." Inspections must be conducted at least once per month.

New Jersey (NJAC 7 1E-2): New Jersey requires that "any leak must be prevented from becoming a discharge." The regulations apply to new and existing "major facilities" – facilities with a storage capacity of greater than or equal to 200,000 gallons. However, existing facilities are exempt from the secondary containment liner requirement if the following conditions are met: (1) the containment system (with a containment volume at least as large as the largest tank) can protect ground water for the period of time needed to clean up and repair or stop the leak; (2) the containment system allows visual inspection for leaks; and (3) the containment system is inspected daily.

- All secondary containment systems must have a permeability of 1×10^{-7} cm/sec or less.
- Dikes, berms, walls, curbing, gutters, ponds, lagoons, and basins are all listed as acceptable secondary containment designs. The system must be capable of containing 100 percent of the volume of the largest enclosed tank, plus have a means for accommodating 6 inches of rainwater.

Leak detection is required in the form of visual inspections. Areas that must be protected include the secondary containment areas and systems, storage tanks, aboveground pipes, and valves. Secondary containment/storage tank areas must be

inspected at least once per week; secondary containment systems that are not impermeable (at existing facilities only) must be inspected daily.

New York (6NYCRR612-614): New York requires a "secondary containment system" around all ASTs with a storage capacity of greater than or equal to 10,000 gallons; or any tank that could reasonably be expected to discharge oil to the waters of the State. The regulations for new facilities are more stringent than the regulations for existing facilities. For example, owners of new facilities with new stationary tanks must: (1) install double bottoms on tanks; or (2) install an "impervious barrier" underneath the tanks.

- The secondary containment system may consist of a "combination of dikes, liners, pads, ponds, impoundments, curbs, ditches, sumps, receiving tanks, and other equipment capable of containing the product stored."

- The system must perform such that "spills of petroleum and chemical components of petroleum will not permeate, drain, infiltrate, or otherwise escape to the ground waters or surface waters of the State."[15] If the secondary containment system is constructed of earthen material, a release may only result in a "minimal amount of soil contamination." For diked systems, the regulation specifies the use of the performance design standards in Section 2-2.3.3 of the National Fire Protection Association's Flammable and Combustible Liquids Code (NFPA 30).

- Although the volume of the diked area need only be 100 percent of the largest tank volume (i.e., no precipitation allowance is stipulated), storm water collection must be controlled with either a manually operated sump or siphon, or a storm drain with manually controlled valves.

- For new facilities, the imperviousness of the double bottom or undertank barrier must be 1×10^{-6} cm/sec or better.

Visual inspection and inventory records reconciliation are required. The visual inspections must concentrate on the exterior surfaces (e.g., valves, pipes, etc.) and leak detection instruments (e.g., gauges or alarms). Visual inspections must be conducted monthly, and reconciliation of daily inventory records "must be kept current."

Rhode Island (OPCR 10-11): Rhode Island requires that a secondary containment system be in place around all oil-storing facilities that have a total storage capacity of greater than 500 gallons. New (or substantially modified) facilities are

[15] New York State provides a guidance document for inspectors and facility owners to aid in understanding the regulations. This document lists some permeability criteria for certain substances, even though no permeability rates are specified in the regulation.

regulated more stringently in that their secondary containment systems must consist of an "impermeable barrier" underneath all aboveground tanks. Rhode Island's regulations are similar to New York State's regulations; in many cases, the language is identical.

- Secondary containment may consist of a combination of dikes, liners, pads, impoundments, curbs, ditches, sumps, receiving tanks, or other equipment.

- The secondary containment system must be constructed so that petroleum spills "will not permeate, drain, infiltrate, or otherwise escape to the ground water or surface water before clean up can occur." Also, if earthen materials are used for the secondary containment structure, a spill should only be able to cause "a minimum amount of soil contamination."

- Dike construction must be in accordance with the standards are specified by Section 2-2.3.3 of NFPA 30, except that the capacity of the secondary containment area must be 110 percent of the largest tank volume.

- For new or substantially modified facilities, "impermeable" is defined as a permeability rate for water of 1×10^{-6} cm/sec or less. The barrier must not degrade in an underground environment or in the presence of oil. In addition, the entire secondary containment area (not just the undertank area) for new facilities must be constructed with a permeability rate for water of 1×10^{-6} cm/sec or less.

Regular facility inspections are required to detect potential leaks. The inspections must focus on all exterior surfaces of tanks, pipes, valves, and other equipment such as gauges, cathodic protection monitoring equipment, or other warning systems. The inspections must be conducted so that any potentially severe structural imperfections are identified, such as cracks, excessive settlement, or corrosion. These inspections must be performed at least monthly.

South Dakota (SCAC 74:03:30): The regulations are applied differently to new and existing facilities and to different sized facilities – new, large facilities are regulated the most stringently. "Small" facilities are those that have a total storage capacity of less than or equal to 250,000 gallons, and "large" facilities are those that have a total storage capacity of greater than 250,000 gallons.

- The containment system for new, "large" facilities may consist of double-walled and/or double-bottomed tanks, dikes, liners, pads, impoundments, curbs, ditches, sumps, receiving tanks, or other equipment capable of holding the material stored. For all containment designs except double-walled tanks, the containment volume must be 110 percent of the largest single enclosed tank. For "new" facilities, the containment structures may be built with native soils, clays, bentonite, or synthetic materials; however,

the permeability of liquid through the finished floors and walls of the containment structure must be 1×10^{-6} cm/sec or less.

- "Small" new and existing facilities must comply with either: (1) the secondary containment requirements, as described in the bullet above; (2) the release detection requirements, as described below; or (3) certain tank performance standards, as outlined in the regulation.

- "Large" existing facilities must build a containment structure around all tanks that is capable of storing 110 percent of the volume of the largest tank. No permeability standard is provided. "Impermeable" barriers (defined as a permeability of 1×10^{-6} cm/sec or less for an unspecified liquid) must be built underneath all aboveground piping, and all piping must be cathodically protected.

"Large" (new and existing) facilities must perform specified leak detection measures; "small" (new and existing) facilities are provided with options for implementing leak detection standards, as described above. Facilities are required to use automatic leak detection equipment, and workers at the facilities also must conduct regular facility inspections. Monthly reconciliations of inventory records shall be made with daily measurements of product storage. Inspections of exterior surfaces of tanks, overfill devices, release detection devices, valves, gauges, and cathodic protection equipment must be conducted. Automatic detection systems shall be continuously engaged. Inspections of equipment must be conducted at least twice per calendar year, not to exceed 15 months between inspections in consecutive years.

Wisconsin (ILHR AR 10): Wisconsin requires lined secondary containment systems, which must perform as "impervious barriers" to the product stored for all aboveground, oil-storing tanks with a storage capacity greater than or equal to 110 gallons at new facilities.[16] Existing facilities are given a choice among various secondary containment options; in addition, existing facilities with a combined storage capacity of less than or equal to 5,000 gallons are completely exempt.

- The term "impervious" is not defined in the regulations, and permeabilities for the floors and walls of the secondary containment area are not specified.

- For new facilities, construction guidelines for dikes are specific: "Dike walls or floors made of earthen or other permeable materials shall be lined with asphalt, concrete, a synthetic or manufactured liner, or prefabricated basin." Dike design must be in accordance with Section 2-2.3.3 of NFPA 30, with the following additions: (1) the volume of the contained area must be 125

[16] For farms, this minimum storage tank capacity is increased to 1,100 gallons.

percent of the largest single tank volume, as opposed to 100 percent as specified by NFPA 30; (2) the walls *and* floors of the contained area must be impervious to the material stored; and (3) provisions must be made for the removal of collected rainwater.

- Existing facilities must comply with one or more of the following by May 1, 2001: (1) all of the secondary containment rules as described above, except that the containment volume may be *either* (a) 125 percent of the largest single enclosed tank volume, or (b) 100 percent of the largest single enclosed tank volume, with provisions for removal of rainwater (with valves or a sump); (2) leak detection, in the form of inventory control/reconciliation, tank gauging, tightness testing, vapor monitoring, or some other approved method; (3) installation of a double bottom on tanks; or (4) lining of the tank interior with a suitable product (the lining must cover the tank's bottom and extend a minimum of two feet up from the exterior grade, along the inside of the tank and the lining must then pass a series of inspections).

Leak detection is not a requirement for new facilities and is contained in the State regulations only as an option for compliance for existing AST systems.

3.2 INDUSTRY PRACTICES AND STANDARDS

EPA conducted a review of industry practices and standards related to liner systems to gather additional information on the technical aspects of these systems and when these systems are recommended. EPA found that although many industry associations have developed detailed standards related to the construction and operation of ASTs, few industry standards or practices explicitly recommend the use of secondary containment liners and/or double bottoms. However, at the time this review was being conducted, several industry associations, including Underwriters Laboratory and the International Fire Code Institute, were revising their recommended practices related to ASTs. API and NFPA recently completed their revisions, and the standards relating to liner systems are briefly summarized below.

In the July 1993 version of the API's Standard 650, "Welded Steel Tanks for Oil Storage," API adopted a policy recommending the use of release prevention barriers in new AST construction. API encourages owners or operators planning to construct new ASTs to consult this document. Double bottoms and undertank liners are both discussed as possible release prevention options. In addition, API states that if the tank owner decides the undertank area is to be constructed for leak detection, then the permeability of the leak detection barrier shall not exceed 1×10^{-7} cm/sec.

NFPA 30, "Flammable and Combustible Liquids Code" (1993 edition) states that "Facilities shall be provided so that any accidental discharge...will be prevented from endangering important facilities, or reaching waterways." Specifically, NFPA requires

that discharge prevention measures be used with aboveground secondary containment-type tanks if they meet any of the following criteria: (1) tank capacity is greater than or equal to 12,000 gallons; (2) piping connections to the tank are below the normal maximum liquid level; (3) prevention systems for liquid released from the tank by siphon flow are not provided; (4) means are not provided for determining the level of liquid in the tank; (5) an alarm (triggered when the liquid in the tank reaches 90 percent of capacity) is not provided; (6) a system which automatically shuts off delivery when the liquid level reaches 95 percent of capacity is not provided; (7) spacing between adjacent tanks is less than 3 feet; (8) the tank is not capable of resisting damage form the impact of a motor vehicle, or does not have suitable collision barriers in place; or (9) emergency venting is not provided between any enclosed interstitial space.

EPA's review of industry standards regarding liner systems indicated that these standards primarily consist of recommended/suggested practices, and not requirements. EPA does not have information on the number of facilities that have installed liner systems due to voluntary compliance with these industry standards.

3.3 ESTIMATE OF THE NUMBER OF FACILITIES ALREADY USING LINERS OR RELATED SYSTEMS

The total number of facilities that could benefit from using liners, presented in Chapter 2, was adjusted to account for facilities located in States that already require liner systems. Specifically, facilities in six States currently must use liner systems that are comparable to liner systems considered in Chapter 4.[17] EPA estimated the number of facilities in these six States that meet the storage capacity threshold of the Oil Pollution Prevention regulation and that are required to comply with State liner requirements. This estimate was developed for each storage capacity tier and by SIC code, and was subtracted from the total number of facilities that meet the storage capacity threshold of the Oil Pollution Prevention regulation to estimate the number of facilities that currently do not to use liner systems. The results of this analysis are presented in Exhibit 3-2. The total number of facilities subject to the six States' liner requirements is estimated to be 83,723. This estimate includes approximately 66,000 "small" facilities, 17,000 "medium" facilities, and 723 "large" facilities. Therefore, the estimated number of facilities not using liner systems currently is about 421,000.

[17] These six states are: Alaska, Florida, New Jersey, New York, Rhode Island, and South Dakota.

EXHIBIT 3-2

ESTIMATED NUMBER OF FACILITIES NOT CURRENTLY REQUIRED TO INSTALL LINERS

Facility Type	SIC Code	Estimated Number Facilities in each of Three Storage Capacity Tiers			
		1,321-42,000 gallons	42,001-1 mill. gallons	> 1 million gallons	Totals
Farms	01/02	121,261	572	0	121,833
Coal Mining/Nonmetal Minerals	12/14	3,084	616	87	3,787
Oil Production	131	138,950	49,743	0	188,693
Contract Construction	15/16/17	2,670	668	0	3,338
Manufacturing:					
Food and Kindred Products	20	2,682	537	82	3,301
Chemicals and Allied Products	28	3,526	668	38	4,232
Petroleum Refining	29	893	690	273	1,856
Stone, Clay, Glass, Concrete	32	3,932	785	40	4,757
Primary Metal Industries	33	1,215	244	155	1,614
Other Manufacturing	20-39	4,795	959	76	5,830
Railroad Fueling	401	0	350	50	400
Bus Transportation	411/413/ 414/417	1,079	269	0	1,348
Trucking/Warehousing/Water Transportation Services	42/446	2,870	717	82	3,669
Air Transportation	458	0	458	0	458
Pipelines	46	183	136	227	546
Electric Utility Plants	491	3,339	542	441	4,322
Petroleum Bulk Stations and Terminals	5171	1,217	7,547	1,887	10,651
Gasoline Service Stations	554	0	5,967	39	6,006
Fuel Oil Dealers	5983	3,154	1,031	107	4,292
Vehicle Rental	751	0	119	0	119
Commercial and Institutional[a]	N/A	47,183	2,635	343	50,161
TOTAL		342,033	75,253	3,927	421,213

[a]Includes military installations, health care, education, and other commercial and institutional facilities.

4. TECHNICAL FEASIBILITY AND UNIT COST OF LINERS AND RELATED SYSTEMS

4.1 OVERVIEW

This chapter presents EPA's evaluation of the technical feasibility of alternative liner systems and estimates of the unit costs to install secondary containment liners and tank double bottoms. EPA investigated the technical feasibility of liner systems by examining the effectiveness of different liner materials and designs for protecting the environment from oil discharges and evaluating the construction feasibility of liner systems. The technical feasibility and unit-cost analysis is based on alternative liner designs for six "model" facilities used to represent the diverse universe of facilities potentially benefitting from the installation of secondary containment liners and double bottoms. The alternative designs examined in this analysis and evaluations of their effectiveness were based largely on discussions with EPA On-Scene Coordinators (OSCs) and owners and operators of facilities using, handling, and storing oil and petroleum products.

The characteristics of the model facilities also were used to develop unit-cost estimates. The estimated costs of installing liners at new facilities and retrofitting liner systems to existing facilities were based on material, installation, and engineering cost information provided by liner manufacturers and installers, and are presented in this chapter in terms of dollars-per-gallon of storage capacity.

The remainder of this chapter is organized as follows. Section 4.2 discusses the six model facilities used to represent AST facilities that currently do not use liners. Section 4.3 presents an overview of liner materials, costs, and effectiveness; current liner practices; and the conceptual designs for the liner systems analyzed in this study. Evaluation of these designs is presented in Section 4.4. Section 4.5 addresses the use of leak detection methods at ASTs.

4.2 DESCRIPTION OF MODEL FACILITIES

The technical feasibility and estimated cost of liner systems were based on the characteristics of six "model" facilities intended to represent the universe of facilities potentially benefiting from the use of liners.[18] The "model facility" approach was selected because the technical feasibility and cost to install and maintain liner systems varies significantly depending on the specific characteristics of a facility (e.g., the number,

[18] The estimated number of facilities not currently using liner systems is presented in Chapter 3.

size, type, and arrangement of tanks). The model facility approach also is necessary because the diverse nature of facilities potentially benefitting from liners precludes developing facility characteristics for each of the 16 industrial categories of facilities with ASTs. Development of the six model facilities, shown in Exhibits 4-1 through 4-6, reflects information previously collected about facilities storing, handling, and using oil.

The six model facilities and their principal characteristics that affect liner installation costs are described below. All of the model facilities are assumed to have secondary containment dikes around their tanks although other forms of secondary containment, such as directed drainage to collection ponds or sumps, also are possible.

Model Facility 1: Small End User - Heating Oil Supply (Exhibit 4-1) consists of a one horizontal 2,000-gallon heating oil tank used to supply fuel to a boiler or furnace for industrial or commercial purposes (e.g., school, hospital, or small manufacturer).[19] The tanks are filled by fuel delivery trucks, and the oil is used on site.

Model Facility 2: Small End User - Motor Fuel Storage (Exhibit 4-2) is a motor fueling operation with a total storage capacity of 24,000 gallons (in three 8,000-gallon horizontal tanks). The tanks are filled by fuel delivery trucks and unloaded to motor vehicles.

Model Facility 3: Type 1 Bulk Storage - Distribution (Exhibit 4-3) is a small bulk plant with a combined storage capacity of 45,000 gallons in three 15,000-gallon shop-fabricated, vertical tanks storing motor fuel and possibly heating oil.[20] Fuel delivery trucks are loaded and unloaded from a loading rack at the facility.

Model Facility 4: Type 2 Bulk Storage - Distribution (Exhibit 4-4) has a combined storage capacity of 104,000 gallons in six horizontal tanks (three of 10,000-gallon capacity and three of 8,000-gallon capacity) and two shop-fabricated, vertical tanks (each of 25,000-gallon capacity). It also has a loading rack area.

[19] Horizontal tanks are cylindrically shaped tanks positioned so that the long axis of the tank is parallel to the ground. Because of this orientation, horizontal tanks are usually supported off the ground by concrete or metal "saddles" conformed to the rounded tank bottom. Horizontal tanks are typically less than 42,000 gallons and are shop-fabricated (i.e., assembled entirely at the place of manufacture).

[20] Vertical tanks are cylindrically shaped tanks whose main axis is perpendicular to the ground. Vertical tanks typically range in size from less than several hundred gallons to over 1 million gallons. Vertical tanks may be shop-fabricated if small, or field-erected (i.e., assembled on-site).

EXHIBIT 4-1

MODEL FACILITY 1: SMALL END USER - SUPPLY

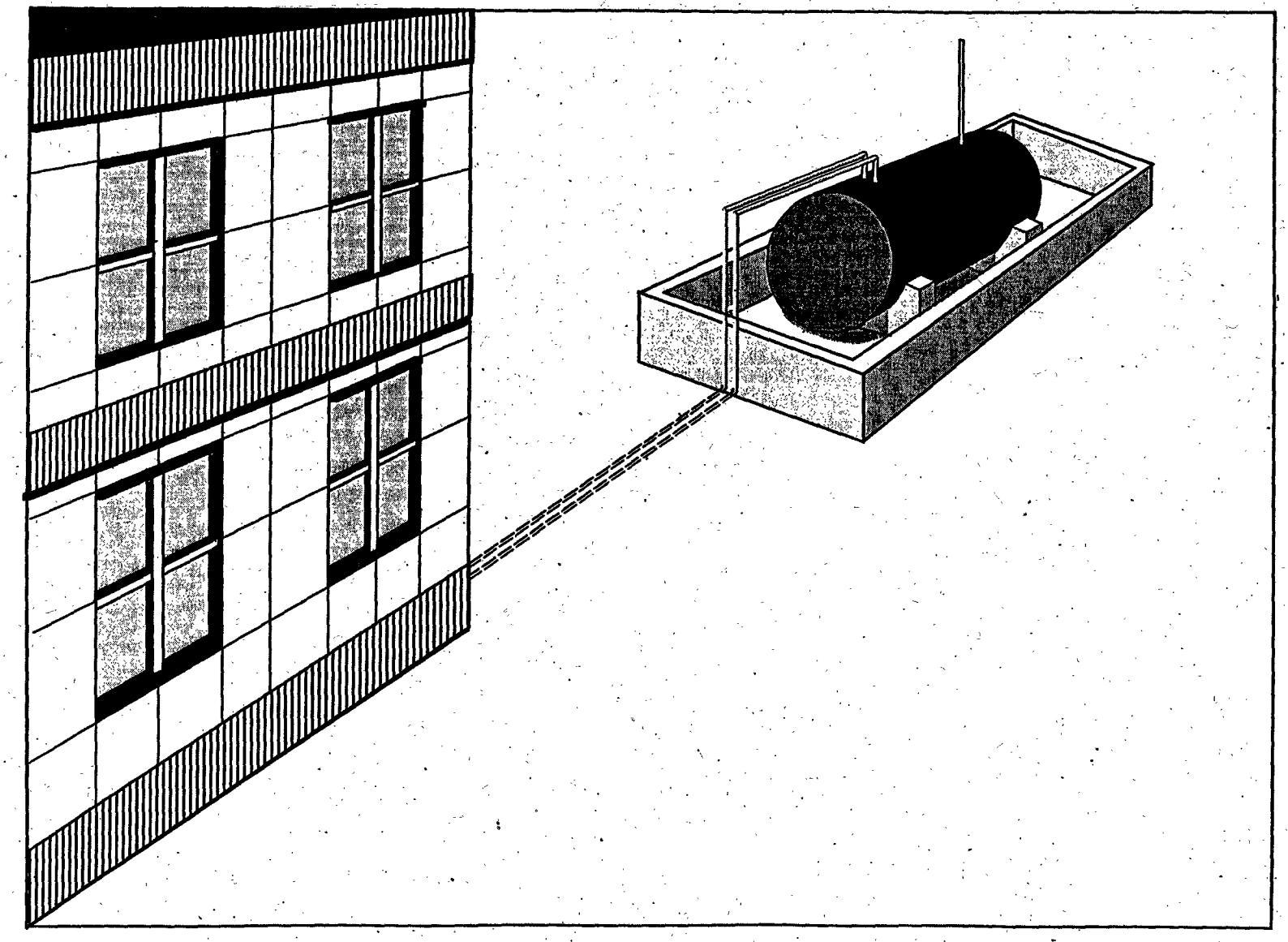


EXHIBIT 4-2

MODEL FACILITY 2: SMALL END USER - STORAGE/MOTOR FUEL

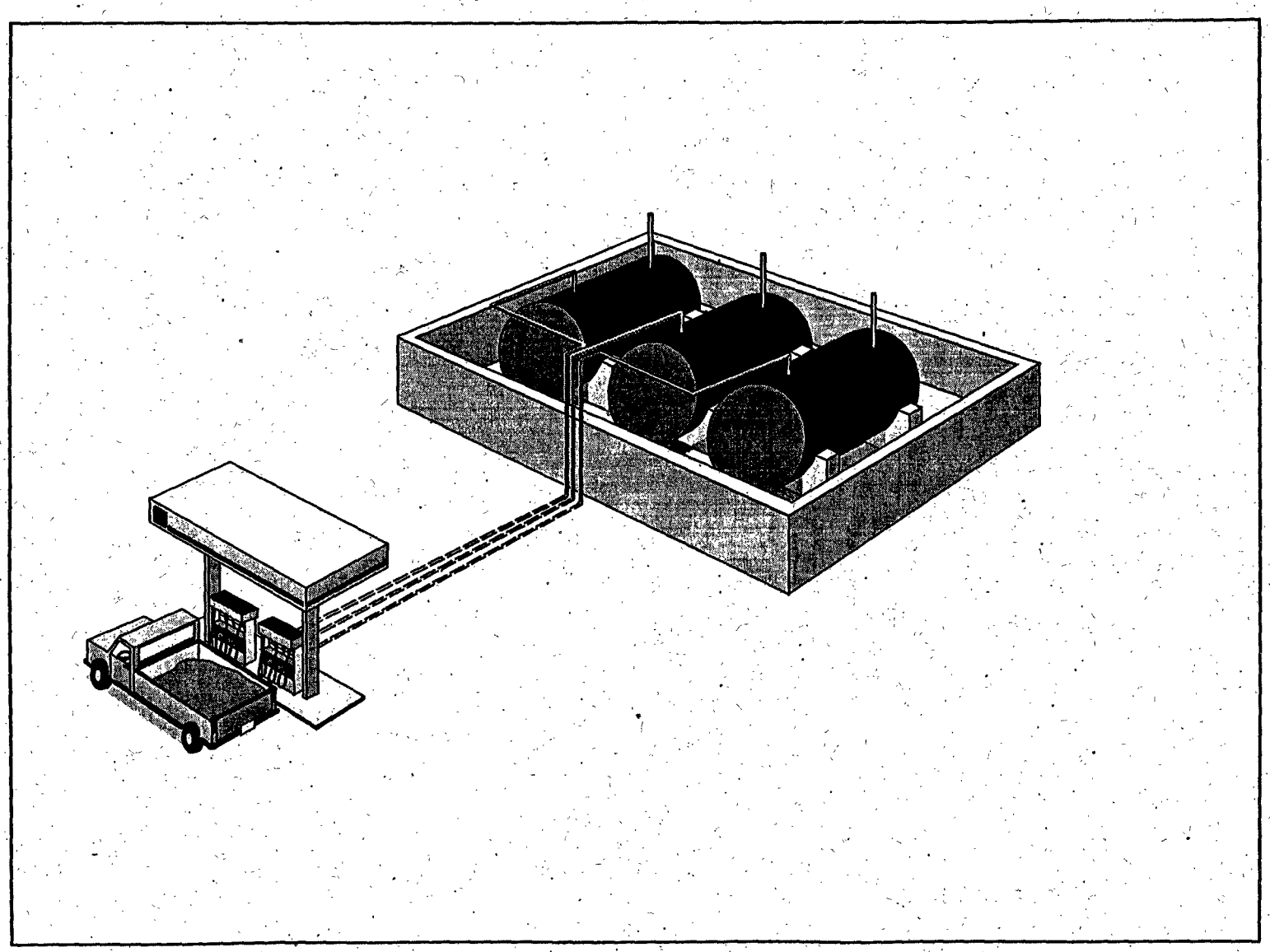


EXHIBIT 4-3

MODEL FACILITY 3: SMALL BULK STORAGE - DISTRIBUTION

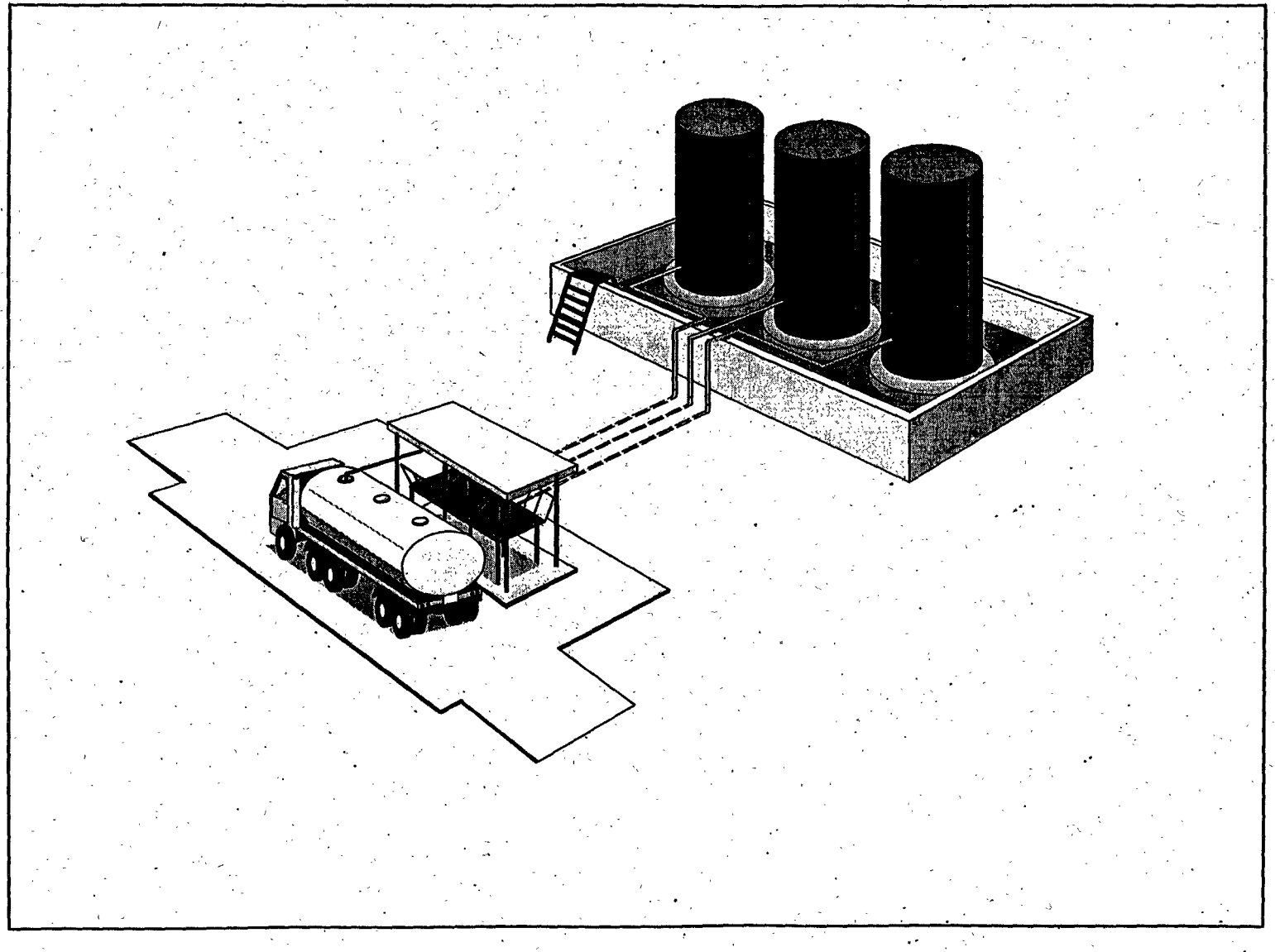


EXHIBIT 4-4

MODEL FACILITY 4: MEDIUM BULK STORAGE - DISTRIBUTION

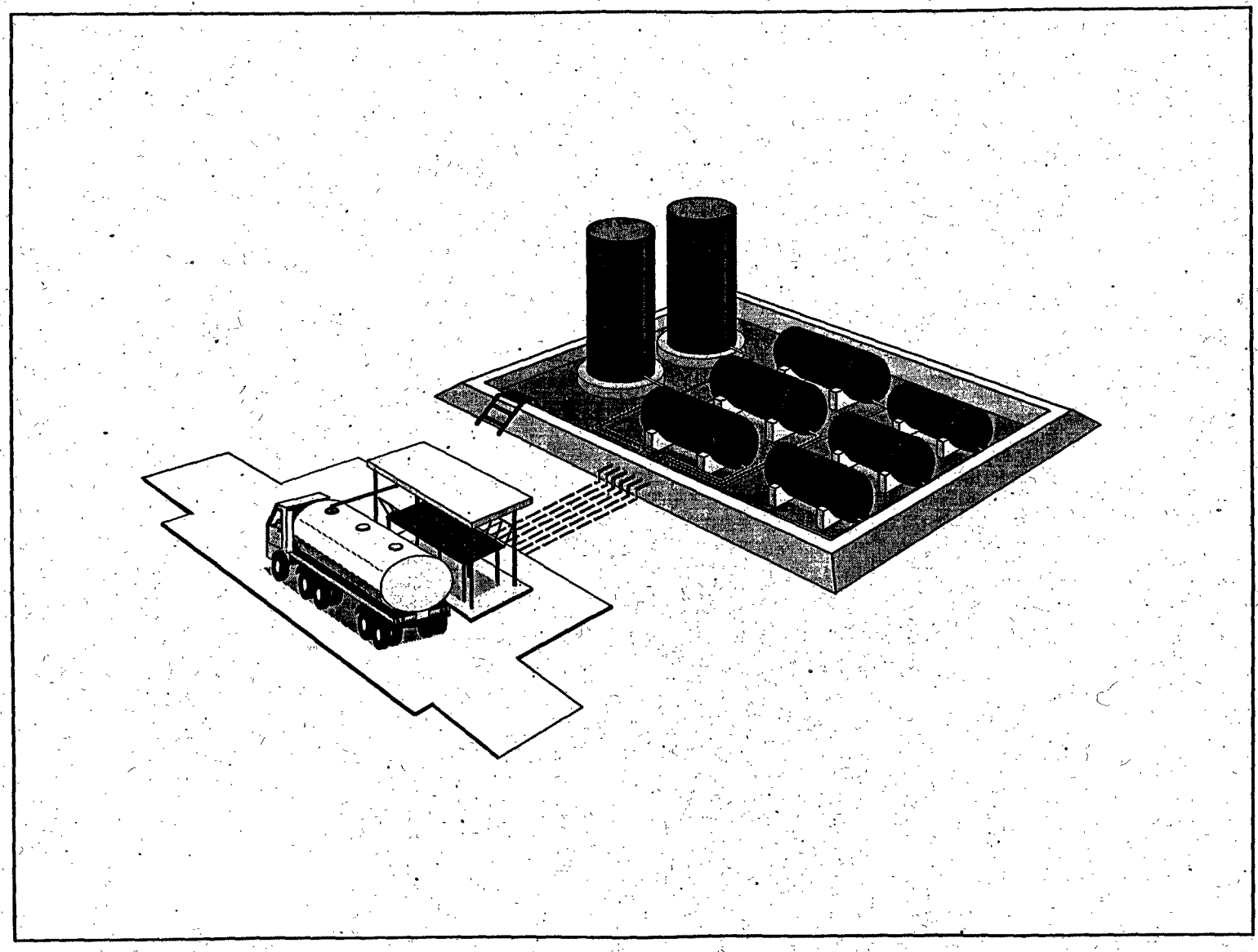


EXHIBIT 4-5

MODEL FACILITY 5: LARGE BULK STORAGE - DISTRIBUTION

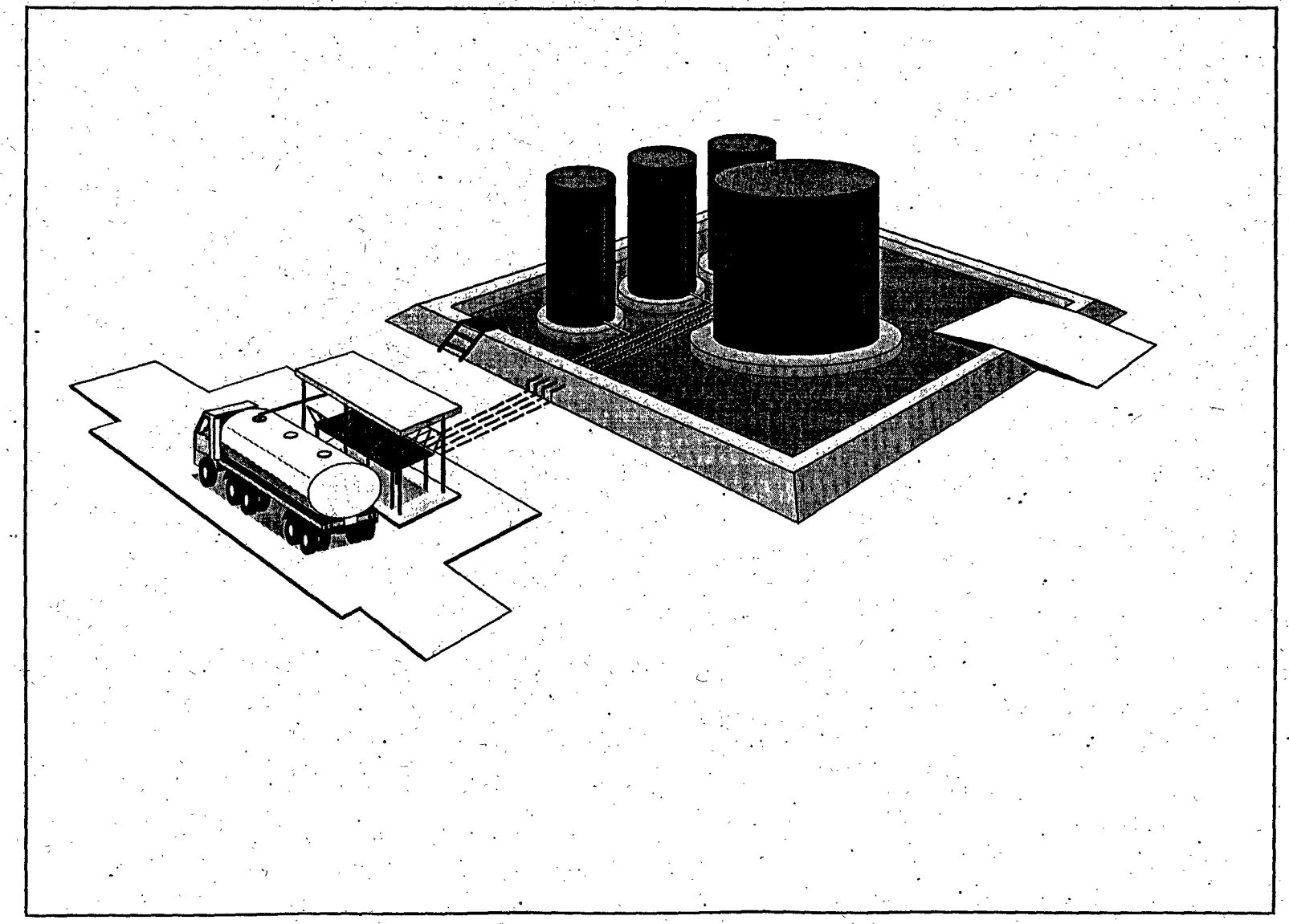
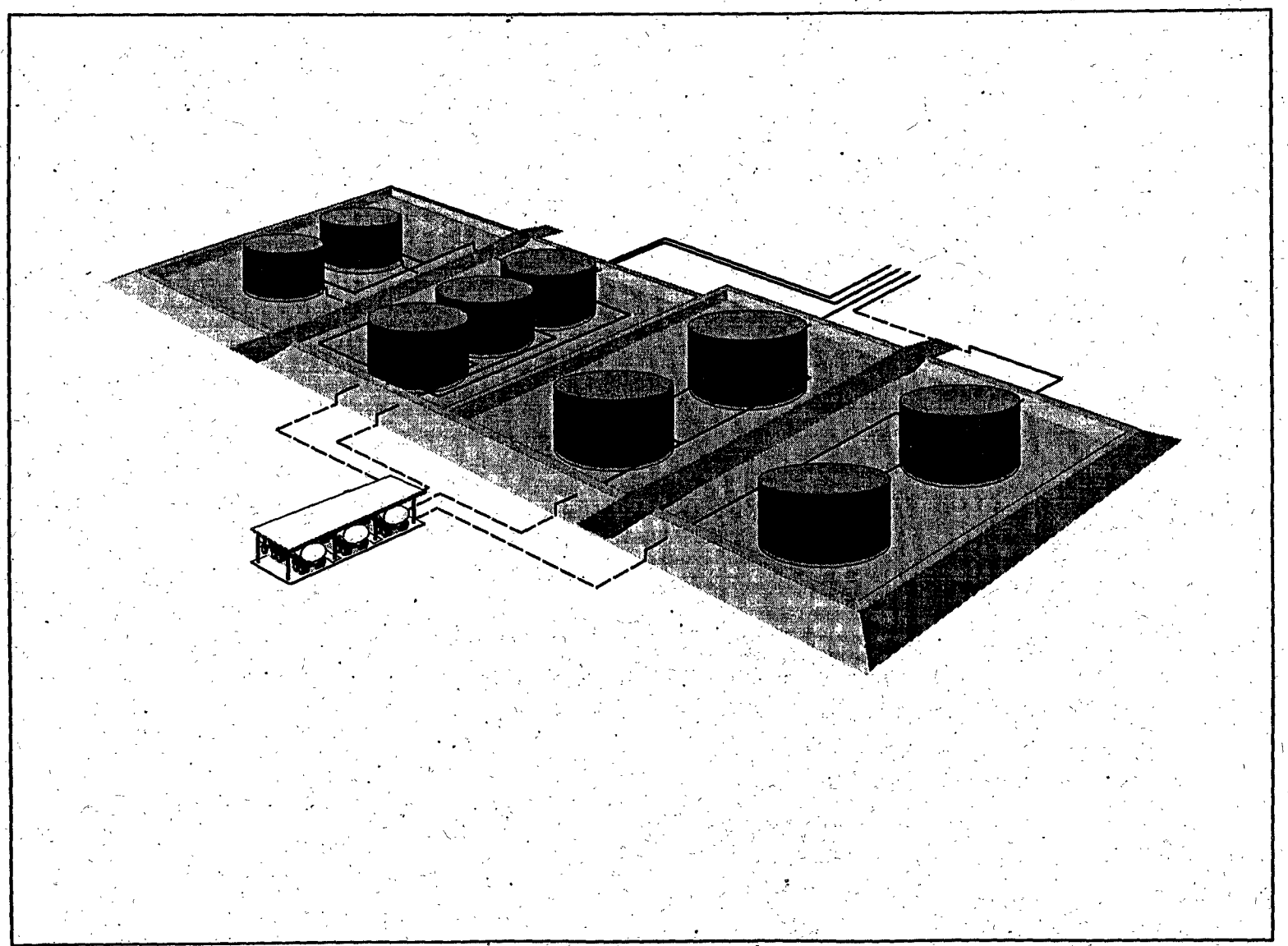


EXHIBIT 4-6

MODEL FACILITY 6: LARGE OIL TERMINAL - DISTRIBUTION



Model Facility 5: Type 3 Bulk Storage - Distribution (Exhibit 4-5) has a total storage capacity of 325,000 gallons, including three 25,000-gallon shop-fabricated, vertical tanks and a 250,000-gallon field-erected vertical tank located on a ring-wall foundation. Loading rack areas for loading and unloading are also present at this type of facility.

Model Facility 6: Large Oil Terminal - Distribution (Exhibit 4-6) has a mixture of nine large-diameter, field-erected, vertical tanks with a combined storage capacity of 50.5 million gallons. The tanks consist of: four 10-million-gallon tanks (200-foot diameter); three 3-million-gallon tanks (120-foot diameter); and two 750,000-gallon tanks (80-foot diameter). Product is transferred to the tanks from barges and/or tankers at off-loading piers and loaded into distribution trucks at loading racks.

The characteristics of the six model facilities are summarized in Exhibit 4-7.

EXHIBIT 4-7

SUMMARY OF CHARACTERISTICS OF MODEL FACILITIES

	MODEL 1	MODEL 2	MODEL 3	MODEL 4	MODEL 5	MODEL 6
Total Capacity (gallons)	2,000	24,000	45,000	104,000	325,000	50,500,000
No. of Tanks	1	3	3	8	4	9
Facility Type	End user	End user	Distribution	Distribution	Distribution	Distribution
Size	Small	Small	Medium	Medium	Medium	Large

Note: Facility size categories are defined as small being 1,321 to 42,000 gallons; medium being 42,001 to 1 million gallons; and large being greater than 1 million gallons.

EPA then estimated the number of AST facilities represented by each model facility. For this report, EPA categorized by "size" and "use" the types of facilities in the 16 industrial sectors identified in Chapter 3 as not currently required to install liners (presented in Exhibit 3-2). The "size" categories are small, medium, or large, and the "use" categories (based on how the oil or petroleum products are used at facilities in that industrial sector) are:

- **Production**, which includes all facilities in SIC code 131 (Oil Production);
- **Storage/Distribution**, which includes all facilities in SIC code 46 (Pipelines), SIC code 5171 (Petroleum Bulk Stations/ Terminals), SIC code 554 (Gasoline Service Stations), and SIC code 5983 (Fuel Oil Dealers); and

- **Storage/Consumption**, which includes facilities in all other industrial sectors.[21]

Exhibit 4-8 shows the results of this categorization by size and use; for example, 138,950 AST facilities are small production facilities (i.e., have a total storage capacity of between 1,320 and 42,000 gallons).

Next, one or more of the model facilities developed for this report was assigned to represent all facilities in each size and use category (e.g., small storage/distribution facilities). This assignment was based on previous analyses conducted by EPA (described in Appendix B) which developed typical storage capacities for facilities in each size and use category. For example, a typical small storage/consumption facility is estimated to have a storage capacity of approximately 2,000 gallons, which is the same as the assumed storage capacity of Model Facility 1. Consequently, all 198,529 small storage/consumption facilities that currently are not required to have liners are represented by Model Facility 1. The results of assigning facilities to the model facilities developed for this report also are presented in Exhibit 4-8.

Several of this report's model facilities represent facilities from more than one size and use category. In addition, because the size categories are broad, certain size and use categories are best represented by more than one model facility. In these cases, the difference between the typical storage capacity of the facilities in that size and use category and the storage capacity of the model facilities in this analysis provided the basis for allocating among two model facilities.[22] For example, small storage/distribution facilities are estimated to typically have a total storage capacity of approximately 10,000 gallons (see Appendix B for a detailed description), for which no single model facility in this report corresponds closely. Therefore, small storage/distribution facilities are best represented by a mix of Model Facilities 1 and 2, which are assumed to have 2,000 and 24,000 gallons of storage capacity, respectively. As the "typical" small storage/distribution facility (10,000 gallons) is closer in storage capacity to that of Model Facility 1 (2,000 gallons) than Model Facility 2 (24,000 gallons), a larger percentage of facilities were allocated to Model Facility 1. Of the estimated 4,554 small storage/distribution facilities, 2,898 facilities are estimated to be best represented by Model Facility 1, and the remaining 1,656 facilities are estimated to be best represented by Model Facility 2.

[21] These size and use categories were originally developed by EPA for use in estimating the costs of implementing the requirements of the Oil Pollution Act of 1990 (U.S. EPA, Emergency Response Division, "Regulatory Impact Analysis of Revisions to the Oil Pollution Prevention Regulation (40 CFR 112) to Implement the Facility Response Planning Requirements of the Oil Pollution Act of 1990", June 1994). See Appendix B of this report for additional information comparing that analysis to the estimates presented here.

[22] An alternative allocation formula was used for medium storage/distribution facilities, as described in Appendix B.

EXHIBIT 4-8

CATEGORIZATION OF FACILITIES NOT CURRENTLY REQUIRED TO INSTALL LINERS

FACILITY SIZE AND USE CATEGORY	PRODUCTION	STORAGE/ DISTRIBUTION	STORAGE/ CONSUMPTION	TOTAL
Small	138,950 facilities Model Facilities 2 and 3	4,554 facilities Model Facilities 1 and 2	198,529 facilities Model Facility 1	342,033
Medium	49,743 facilities Model Facility 4	14,681 facilities Model Facilities 3 and 5	10,829 facilities Model Facilities 4 and 5	75,253
Large	Negligible Not Applicable	2,221 facilities Model Facility 6	1,706 facilities Model Facility 6	3,927
Total	188,693	21,456	211,064	421,213

Note: Size categories are defined as small being 1,321 to 42,000 gallons; medium being 42,001 to 1 million gallons; and large being greater than 1 million gallons.

The estimated total number of facilities represented by each model facility is as follows:

• Model Facility 1:	201,427
• Model Facility 2:	49,296
• Model Facility 3:	97,277
• Model Facility 4:	55,623
• Model Facility 5:	13,663
• Model Facility 6:	3,927
Total # Facilities	421,213

4.3 LINER SYSTEM DESIGNS AND PRACTICES

Liners are engineered systems that enhance the imperviousness of secondary containment structures that surround ASTs.[23] Secondary containment structures vary greatly depending on the size of the tanks and the physical characteristics of the facility and may be constructed of compacted native soil (e.g., clay), concrete, or other synthetic material.[24] Secondary containment structures are typically designed to hold the entire contents of the tank or tank battery within the structure and serve to contain any spilled oil or product in the event of a leak or sudden discharge. Liners may be installed within secondary containment structures in several ways. Liners may be placed to cover the entire interior area of a secondary containment system, including the area beneath any tanks (i.e., undertank liners). Alternatively, especially for facilities with existing vertical tanks in direct contact with the ground, liners may be installed throughout the interior area of the secondary containment except underneath existing vertical tanks. Although it is technically feasible to move an existing AST temporarily in order to install an undertank liner beneath its normal resting area, it is usually considerably more expensive than installing a double bottom, which serves the same purpose of protecting against leaks from failing tank bottoms.

Double bottoms protect against leaking or failing tank bottoms in vertical tanks. When in direct contact with the ground, the tank bottom is susceptible to corrosion (rusting of the metal), which eventually reduces the thickness of the tank bottom, resulting in the development of perforations (e.g., pinpoint holes) and, if left unrepaired, rips and tears. In contrast, horizontally mounted tanks are smaller and are much less susceptible to corrosion because they are typically supported off the ground by concrete or metal saddles or other platforms. Double-bottom tanks have a second steel surface above the outer tank bottom or tank foundation to provide additional protection against

[23] Secondary containment is a general term that includes all structures designed to channel and contain a spill or leak from an AST or storage facility. Secondary containment structures may include graded surfaces leading to a collections pond, diked or bermed areas around tanks, or sumps.

[24] Some of these materials also may be used as liners to secondary containment structures made of more permeable materials.

leaks in the event of corrosion-induced failure of the bottom surface. Generally, the interstitial space between the two steel bottoms of the tank includes a geosynthetic liner and a leak detection system. Although the choice of a second steel bottom may provide additional opportunity for corrosion, the interstitial leak detection system would alert the facility operator to any failure of the system, and the geosynthetic liner would prevent oil from discharging to the environment until repairs could be made. The space around the interstitial liner and leak detection system also is filled with concrete or sand to provide additional structural support to the inner tank bottom. For purposes of this report, EPA analyzed double bottoms as "other means of secondary containment," which could be used in place of undertank liners.

EPA analyzed other alternatives to double bottoms, but did not find these options to be as usable as double bottoms. For example, one of the options considered was the use of electronic fluid flow indicators in horizontal wells placed beneath ASTs to detect leaking petroleum products. Although this technology is relatively inexpensive, it detects a leak only after oil has contaminated the underlying soil. For purposes of this study, double bottoms are preferred over this option because double bottoms would aid in detecting a leak before soil contamination could occur.

Another option considered was the installation of a geomembrane liner along the inside walls and bottom of an AST. Although this option is not a form of leak detection, it is a viable method for preventing oil from leaking into the underlying soil provided that the product stored in the AST is compatible with the liner material. If it is not, degradation of the liner could occur. The use of double bottoms, however, would provide greater flexibility in the type of product that could be stored in the AST.

To gather information on current industry practice relating to liners, EPA surveyed OSCs (EPA technical staff directly implementing the current SPCC Program), facility owners and operators, liner manufacturers and installers, and State officials responsible for AST regulatory programs.[25] These interviews were meant to provide a general assessment of the advantages and disadvantages of various liner designs and materials from a broad representation of knowledgeable sources. The interviews were intended to gather background information rather than be a rigorous, scientifically valid survey. The following section summarizes the information obtained from the interviews on five topics: the types of liner materials in use, the costs of using liners, liner use practices, opinions on liner effectiveness, and leak detection practices.

[25] OSCs from each of the 10 EPA Regions, 13 facility owners/operators in 10 States, 15 liner manufacturers, 7 installers, 2 manufacturers of spray-on coatings, and State environmental agency staff in all 50 States were contacted. Three representatives of the insurance industry were also contacted regarding the availability of data on the probabilities and sizes of discharges from ASTs. However, these insurance industry contacts were not able to provide any new information beyond that already identified from other sources.

4.3.1 Liner Materials Currently in Use

Impervious soils[26] (clay, soil-bentonite mixtures), concrete, bituminous concrete, geomembranes (polymeric sheets and bentonite mats), and steel liner systems are all used by industry. Spray-on liner systems also are available and tend to be used in conjunction with concrete secondary containment structures, although some manufacturers have developed spray-on systems that work with earthen berms (the material adheres to and seals the surface of the dike wall or berm, preventing product from permeating through cracks or other imperfections).

Facility owners and operators reported that most secondary containment structures are made from earthen materials. Five out of 13 facility owners/operator respondents further indicated that impervious soil was the preferred liner material. In contrast, manufacturers and installers reported that synthetics were the most common materials used for secondary containment liners. The synthetic materials most often cited by the manufacturer and installer respondents were high density polyethylene (HDPE), polyvinyl chloride (PVC), XR-5®, Hypalon®, and Hytrel®.

4.3.2 Cost of Liners

Opinions varied on the cost to install, operate, and maintain liner systems. Several owners and operators mentioned that, in their experience, maintaining geomembrane systems is expensive. However, several liner manufacturers asserted that geomembrane liner systems have low operation and maintenance (O&M) costs following the initial installation; most of the liner manufacturers and installers interviewed suggested that the only routine maintenance necessary is a periodic inspection, and repair if damage is found.

Installed liner cost quotes from different companies varied significantly, even for identical liner materials. In addition, recommended liner thicknesses also varied significantly for identical liner materials and applications.

4.3.3 Liner Use Practices

In general, liners are not consistently used throughout the industry. Five of the 13 owners/operators who were contacted said that liners were not used at their facilities. Four facilities had incorporated liners into new designs and on some retrofitted tanks and secondary containment structures. OSCs and owners/operators agreed that liner systems are used primarily at large facilities (i.e., with total storage capacity greater than 1 million gallons) and that small facilities (i.e., less than 42,000 gallons) usually use liners only when mandated by State regulations.

[26] For purposes of this report, the term "impervious soil" means a naturally occurring or adapted soil that has a hydraulic conductivity of 1×10^{-6} cm/s or less.

The liner manufacturer and installer respondents stated that, while some existing facilities are being retrofitted with new tank bottoms (double bottoms) and liners in secondary containment areas, it is mostly *new* facilities that are protected with these systems. Most respondents agreed that, in general, few existing facilities appear to be retrofitted with liner systems, except in the States that mandate liners.

State regulation of ASTs, including the required use of liners, varies. Twenty-seven States have adopted, in varying degrees, the National Fire Protection Association (NFPA) standards or other fire codes related to ASTs. Fifteen States have specific AST requirements in their regulations; seven States require liners at AST facilities.[27] Of the seven States that require liners, six specify maximum permeability liners. Two additional States are proposing liner regulations with specific permeability requirements. Four States specify that AST facilities must adhere to the Oil Pollution Prevention regulation, while another four States delegate the regulation of ASTs to local agencies. Four States that currently do not regulate ASTs have proposed or will be proposing AST regulations.

4.3.4 Liner Effectiveness

Liner manufacturers and installers report that the *design* life of a liner is between 15 and 30 years, except for spray-on liners whose design life is between 8 and 15 years. These numbers are conservative estimates of the life span of a liner based on the manufacturer's warranty, which is derived from accelerated tests performed to evaluate liner effectiveness and longevity.

Although OSCs have limited experience with liners, those interviewed agree that with proper installation and maintenance, liners are effective in preventing ground-water contamination and in detecting leaks from AST bottoms.[28] However, facility owner/operator respondents stated that liner maintenance is not always a high priority, and poor maintenance can significantly reduce the effectiveness of certain types of liners.

Each type of liner has different requirements with regard to proper maintenance and repairs, as briefly described below.

- **Impervious Soil.** Some silty clay liners require constant or periodic hydration using a sprinkler or irrigation system. Facilities also sometimes apply controls to prevent liner penetration from animal activity or undesirable vegetation, and regularly inspect the liner for damage from heavy precipitation, erosion, and settling. If the original soil liner is damaged, it may need to be completely replaced.

[27] See Chapter 3 for a discussion of State regulations and industry practices related to liner systems.

[28] OSCs also noted that most spills occur outside of the tank secondary containment areas, such as at loading racks during product transfer operations. Such spills would not be addressed by liners in tank secondary containment areas.

- **Coated or Uncoated Concrete.** Some concrete liners may require evaluation of the expansion/contraction joints. Such an evaluation could include periodically confirming wall-to-floor integrity, and checking for cracking. Facilities also typically evaluate the integrity of concrete coatings.

- **Geomembranes.** Routine maintenance of geomembrane liners typically includes visual inspection of liner integrity and, in some cases, testing of the seams. Facilities may also use controls to prevent liner penetration from animals or vegetation.

4.3.5 Liner Designs Used in this Study

For this study, EPA developed representative liner system designs that could be used at the six model facilities as a basis to evaluate liner system technical feasibility and installation costs. To provide a visual description of how different types of liner system designs can be applied at a facility, Exhibit 4-9 shows a general schematic of a *generic* AST facility, consisting of a single, large, vertically-mounted AST; a smaller, horizontally mounted AST; an aboveground piping system; and a lined, diked containment area with an access road within it.

Exhibit 4-9 also indicates the areas of the generic facility that are presented in detail in Exhibits 4-10 through 4-14, as described below. Some designs may be more suitable than others for various liner applications.

- **Exhibit 4-10** presents cross-section details of liner installations in a containment area using four alternative types of liner materials: an impervious soil liner, a concrete liner, a geomembrane liner, and a bentonite mat liner. Although the designs depicted are typical examples, various designs and installation methods exist for these liner materials.

- **Exhibit 4-11** shows details of the liner system at the interface of the vertical tank (i.e., where the tank base meets the liner material) for the same four liner materials as shown in Exhibit 4-10. These drawings show that liner systems do not protect against discharges from tank bottoms.

- **Exhibit 4-12** details methods for securing liners to tank foundations and foundations for above-ground piping supports that penetrate the floor of the secondary containment area.

- **Exhibit 4-13** presents designs for installing liners where access roads are entirely within the secondary containment area.

EXHIBIT 4-9

GENERAL SCHEMATIC: ABOVEGROUND STORAGE FACILITY

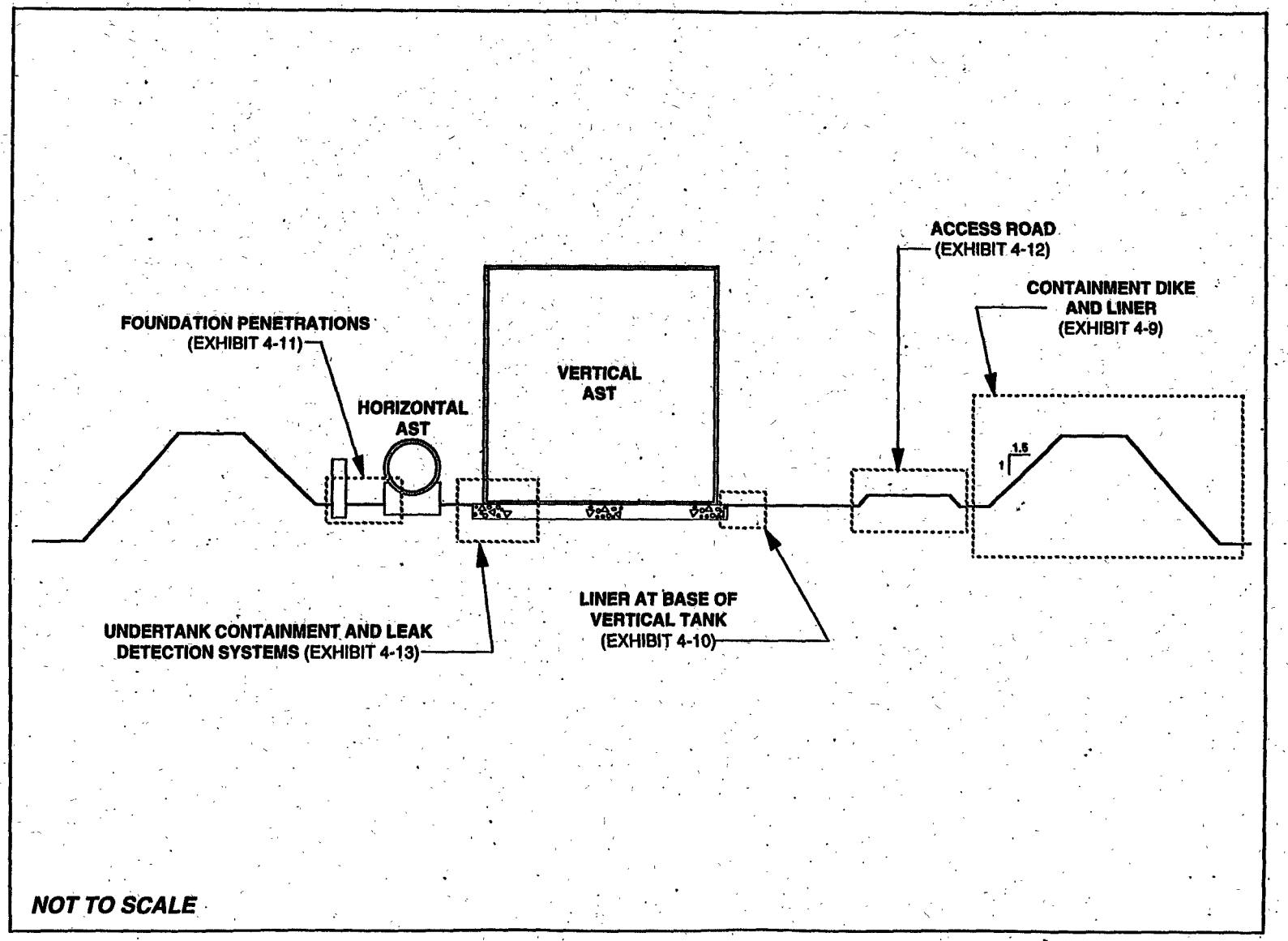


EXHIBIT 4-10

DETAILS: CONTAINMENT DIKE AND LINER

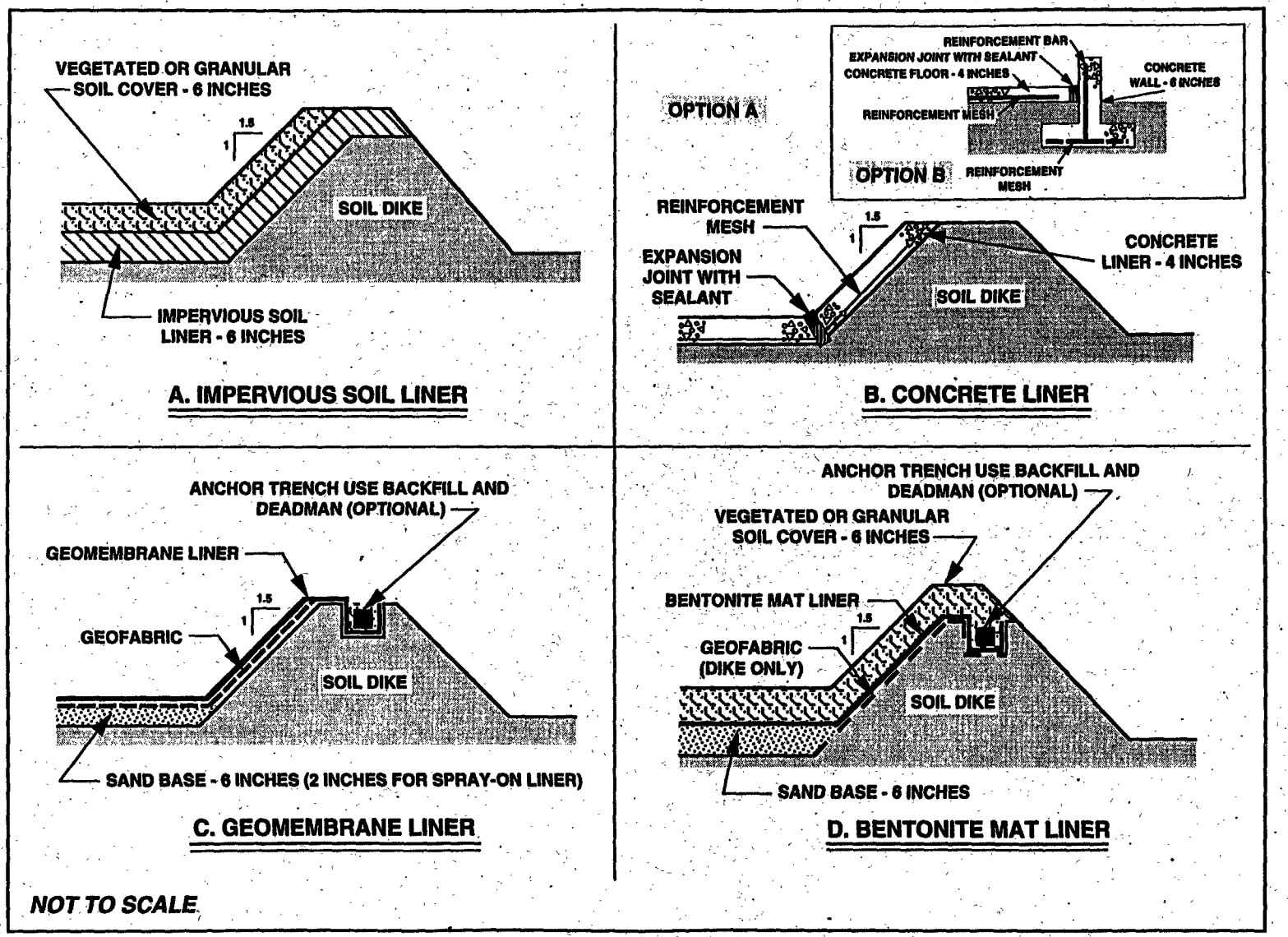


EXHIBIT 4-11

DETAILS: LINER AT BASE OF VERTICAL TANK

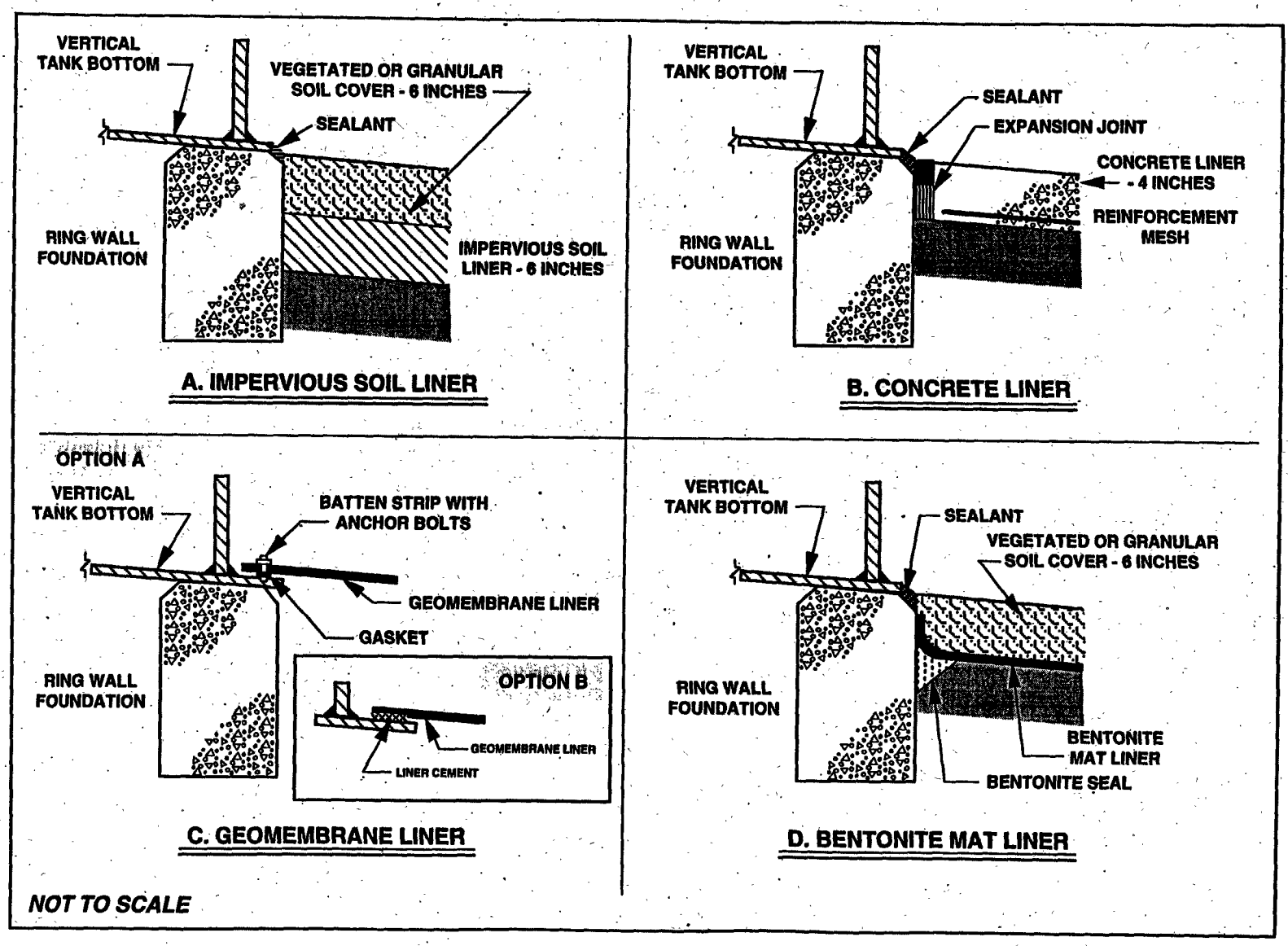


EXHIBIT 4-12

DETAILS: FOUNDATION PENETRATION

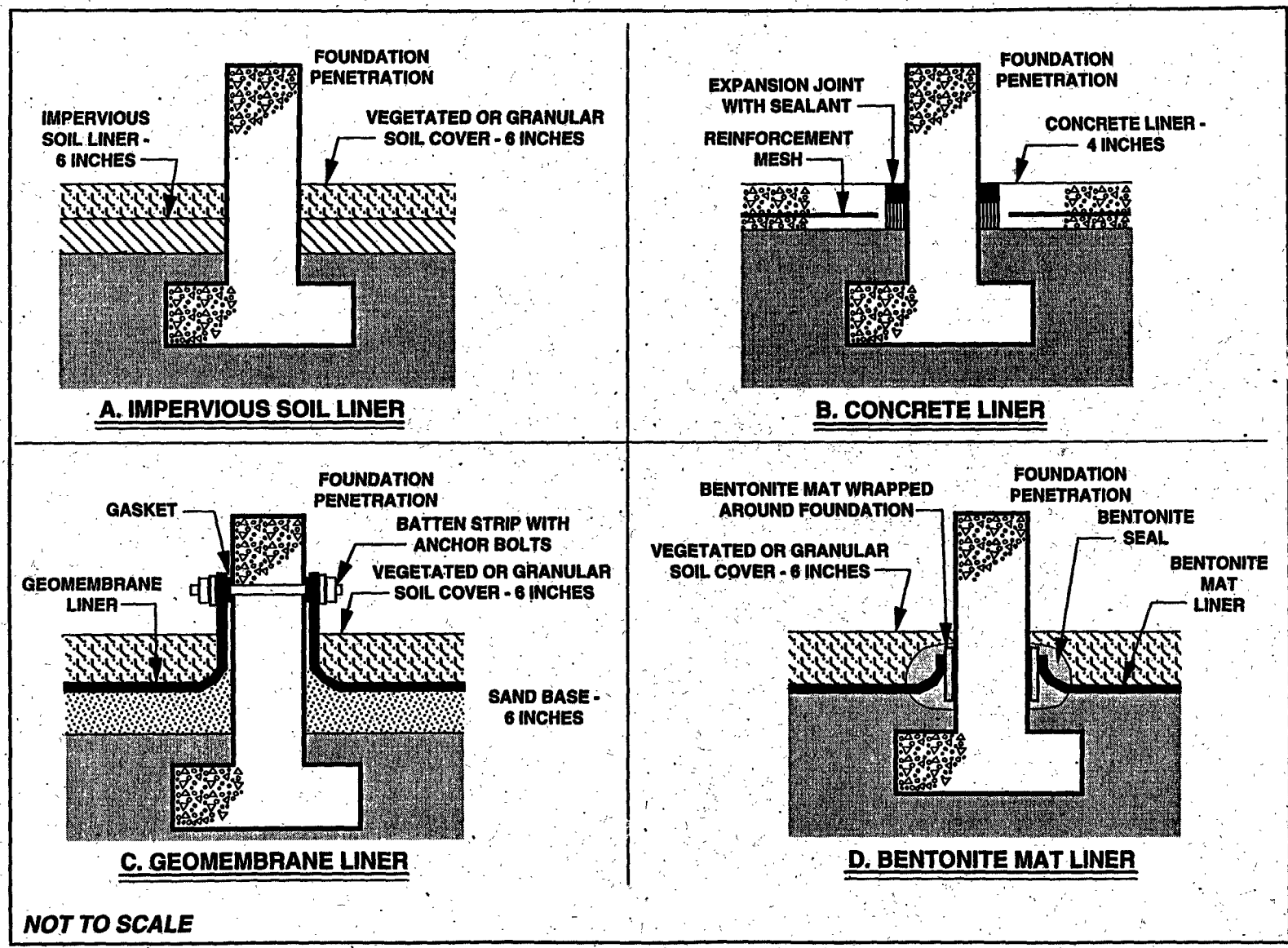
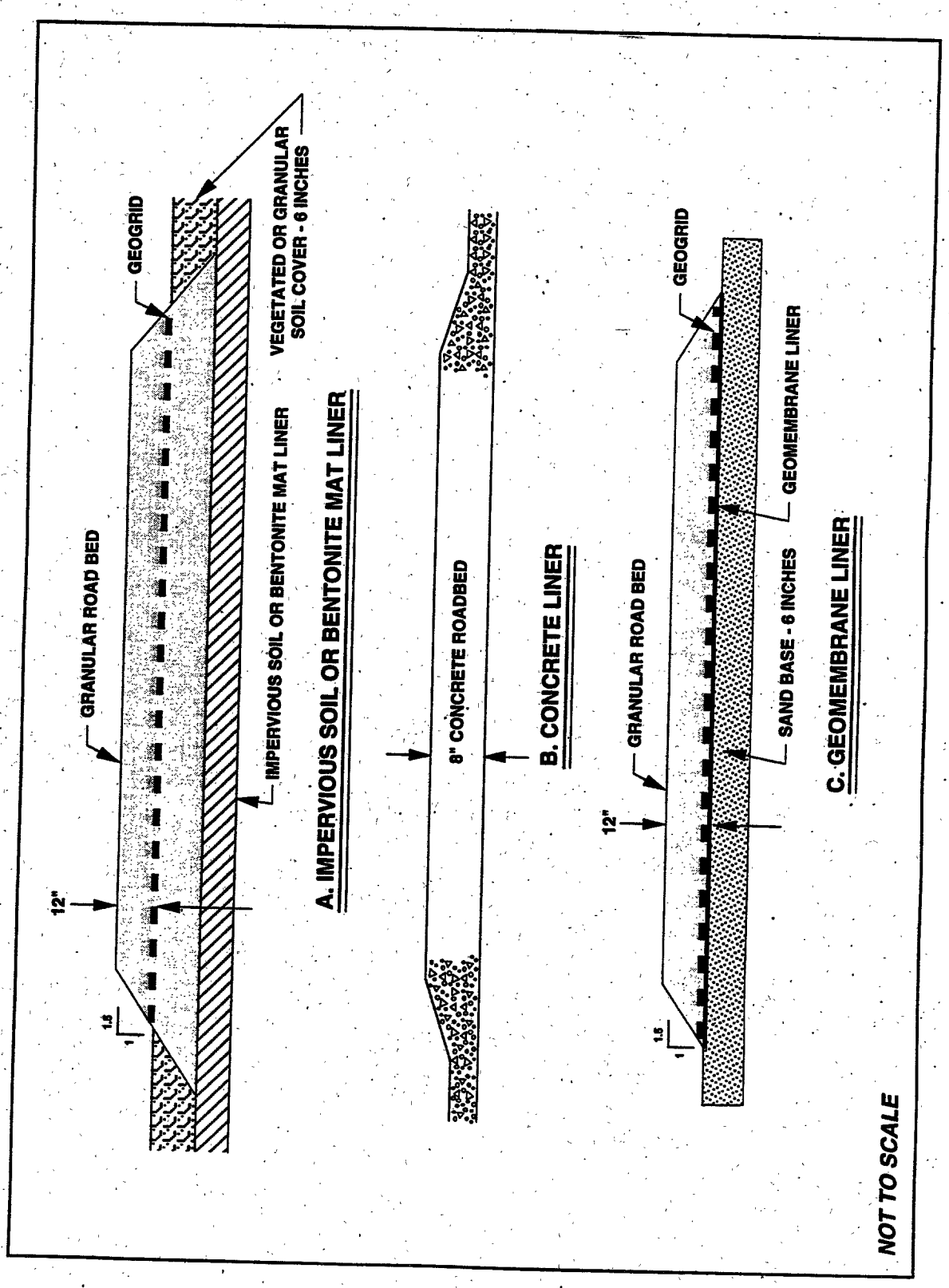


EXHIBIT 4-13

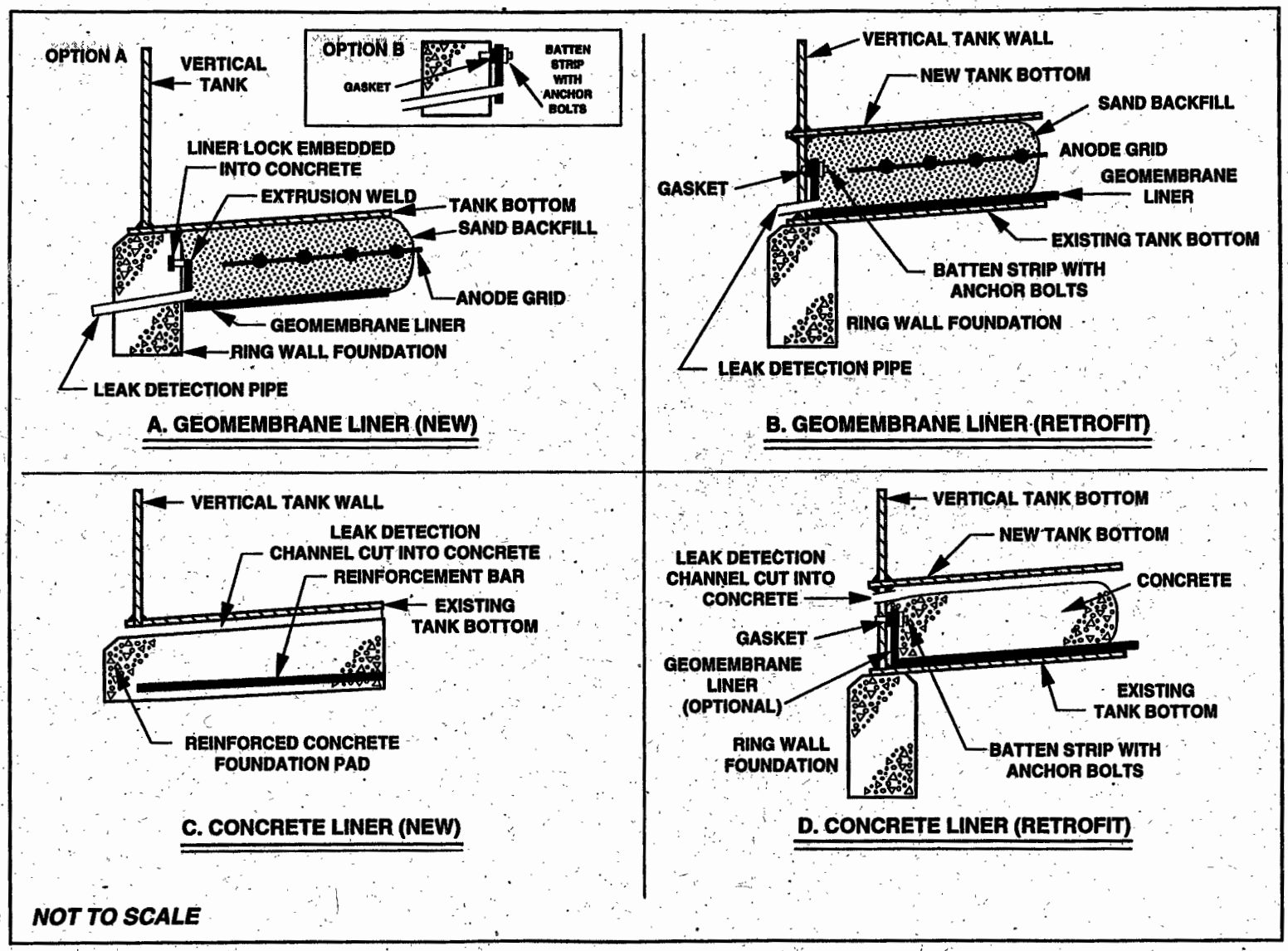
DETAILS: ACCESS ROAD



57

EXHIBIT 4-14

DETAILS: UNDERTANK CONTAINMENT SYSTEM



- **Exhibit 4-14** presents four possible designs for addressing leaks from tank bottoms of vertical ASTs, which may not be controlled by a secondary containment liner system.[29] Two designs are for undertank liner systems installed with new tanks, while the other two are for retrofitting existing tanks with double bottoms and leak detection systems.

4.4 LINER FEASIBILITY EVALUATION

EPA assessed the technical feasibility of liner systems based on the degree of environmental protection afforded, ease of construction, and cost, as described below.[30]

- **Environmental Protection.** Environmental protection constitutes protecting ground water, aiding in leak detection, and preventing oil spills from reaching surface waters. The degree of environmental protection provided by a liner system depends on its permeability, which is influenced by among other factors: workmanship in installation; quality and regularity of upkeep; chemical resistivity; resistance to weathering caused by ultraviolet exposure, freeze/thaw cycles, erosion, and wet/dry cycles; and resistance to other damage caused by vandalism, animal activity, and undesirable vegetation.

- **Ease of Construction.** Factors that complicate construction include constrained site conditions, adverse climatic conditions, material availability, and the skill of the installers.

- **Cost.** Cost includes capital costs for materials and installation, annual operating costs (e.g., animal and vegetation control, security, and hydration of clay-based material) and maintenance costs, such as liner system repairs.

Exhibit 4-15 summarizes the feasibility of using liners at oil-storing AST facilities for environmental protection and shows the constructibility of liner systems. Liner systems are rated relative to each other on a scale from 1 to 5, where 1 is distinctively inferior to other ratings and 5 is distinctively superior.

---

[29] Undertank leaks are often very difficult to detect. The potential damage to the environment from an undertank leak is decreased greatly when an undertank liner is in place. EPA found that a number of potential designs are available for undertank containment and leak detection and evaluated two commonly used designs shown in Exhibit 4-14. Both designs include leak detection, which should be an integral part of every undertank containment design.

[30] Information in this section is intended to provide a general comparison of liner materials and their relative advantages and disadvantages. This information should not be construed as constituting governmental approval of any specific design or product; EPA does not endorse or recommend specific liner products or materials.

EXHIBIT 4-15

COMPARATIVE ANALYSIS OF LINERS FOR ENVIRONMENTAL PROTECTION AND CONSTRUCTION EASE

FEASIBILITY CRITERIA	ALTERNATIVE SYSTEMS							
	IMPERVIOUS SOIL		CONCRETE		GEOMEMBRANES			STEEL
	NATIVE SILTY CLAY	MODIFIED SOIL	UNCOATED	COATED	POLYMERIC SHEETS	BENTONITE MAT	POLYSULFIDE SPRAY-ON	
ENVIRONMENTAL PROTECTION								
1. Inherent Permeability	3	3	2	4	4	4	5	5
2. Workmanship Requirements	High	High	Moderate	Moderate	Moderate	Low	Moderate	Moderate
3. Chemical Resistivity	5	5	5	4	2 to 4	5	4	5
4. Resistance to Weathering Caused by:								
• ultraviolet exposure	NA	NA	4	3	3	NA	3	5
• freeze/thaw action	2	2	2	3	5	3	5	5
• erosion	2	2	4	4	5	3	5	5
• wet/dry cycles	2	1	4	4	5	1	5	5
5. Resistance to Other Damage Caused by:								
• vandalism	5	5	5	3	2	5	3	4
• animal activity	2	2	5	4	3	2	3	5
• undesirable vegetation	2	2	3	5	5	2	5	5
CONSTRUCTION EASE								
1. Adverse Site Conditions[a]	High	Low	High	High	Low	Moderate	Moderate	Moderate
2. Adverse Climatic Conditions[a]	High	Moderate	Moderate	Low	High	High	Low	Moderate
3. Material Availability	2	3	3	3	5	5	5	4
4. Availability of Skilled Labor	2	5	4	3	3 to 4	4	3	2

NOTES: [a] "High" indicates that construction of the liner would be difficult under the conditions listed under the Feasibility Criteria, "Moderate" indicates that construction of the liner would be moderately difficult, and "Low" indicates that construction of the liner would be relatively easy under the conditions listed under the Feasibility Criteria.

NA = Not Applicable

Alternatives are rated relative to each other on a scale from 1 to 5 (inferior to superior).

4.4.1 Protection of the Environment and Construction Ease

Impervious soil. Impervious soils (see footnote #26) include native silty clay and soils mixed with bentonite. The inherent permeability of these soils is rated in the mid-range among the liner materials that were evaluated; however, oil resistivity is high. Impervious soil liners are susceptible to degradation from weathering, animal activity, and vegetation. Construction of liners from impervious soils is relatively simple at new facilities, but generally more difficult at existing facilities.

Concrete. Concrete is widely used for secondary containment, especially at smaller facilities. The ability of concrete containment structures to protect the environment varies depending on the condition of the concrete surface, particularly its degree of cracking. Uncoated concrete is more permeable than coated concrete, whose permeability is similar to that of geomembranes, and both coated and uncoated concrete are highly resistant to oil. Both coated and uncoated concrete are relatively resistant to weathering except that uncoated concrete is susceptible to damage from freezing and thawing especially if the concrete is cracked. Concrete systems are generally easy to construct in new applications and more difficult for retrofit applications of existing obstructions such as pumps and pipes.

Geomembranes. A wide range of geomembrane liner materials are available, including polymeric sheets, bentonite mats, and spray-on coatings compounded with polysulfide. The inherent impermeability of liners made from these materials is high, and oil resistivity is generally good. These protective qualities can be degraded by weathering caused by exposure to the sun and, in the case of bentonite mats, cracking caused by wet/dry cycles. Exposed geomembranes and polysulfide coatings may be susceptible to damage from vandalism or animal activity. Animal activity and undesirable vegetation are also of concern with bentonite mats. Repairs to geomembrane liners may be costly and must be made promptly upon discovery. The ease of installing geomembrane liners varies depending largely on the stiffness of the material. Geomembrane liner systems can be installed in either new or existing facilities.

Steel. Steel liner systems are not widely used, although they are well suited for small horizontal tanks (up to approximately 20,000-gallon capacity) and when space limitations require erection of a high vertical wall. Because steel resists all oil products and is essentially impermeable, it is highly protective of the environment. Compared to other liner systems, steel liner systems offer the greatest resistance to weathering and other damage. Construction of steel liners requires extensive design and planning prior to installation, and steel liner systems are generally more difficult to install in existing facilities than in new facilities because of existing obstructions such as pipes and pumps. Retrofitting existing containment areas may pose safety problems because welding may be required close to flammable products; as a result, tank contents may have to be removed and the tank cleaned before the installation can begin. Compared to other liner systems, steel is not economical for most facilities.

4.4.2 Estimated Facility Costs

The estimated capital unit costs for both retrofitting existing facilities and for installing liner systems at new facilities are shown in Exhibit 4-16. O&M costs are addressed qualitatively in Exhibit 4-17. The cost estimates presented in the exhibits are meant to be representative estimates based on the characteristics of the model facilities rather than definitive estimates applicable to a specific type of facility. Capital costs for existing facilities are based on installing a secondary containment liner system (except underneath tanks) and installing double bottoms on all vertical ASTs.[31] For new facilities, costs are estimated assuming that undertank liners would be installed along with the secondary containment liner.

The exhibits do not include steel liners because their cost is prohibitive except in special circumstances. Costs are presented in 1991 dollars, corresponding to when most of the information on installation and O&M costs was collected. The cost estimates presented in the exhibits were developed based on information in the 1991 Means construction cost data estimating guide, which presents average costs for 30 major cities.[32] In addition, the cost estimates reflect the following assumptions:

- Grubbing, soil excavation, and grading costs are not included in the cost estimates for new facilities, but are included in the estimates for installation at existing facilities.
- Concrete liners are 4 inches thick.
- Liners comprising polymeric sheets are placed on top of a layer of sand 6 inches deep.
- Liners comprising bentonite mats are covered with 6 inches of soil that is seeded with grass, fertilized, and mulched.
- The cost of installing an impervious soil liner involves the material price, loading, hauling 5 miles one way, dumping, spreading, and compacting.
- The liner is assumed to be covered with 6 inches of soil that is seeded with grass, fertilized, and mulched.

[31] Vertical ASTs are assumed to rest on concrete pads that provide protection comparable to a double bottom. Horizontally mounted tanks are assumed to be supported off the ground by saddles, which allows installation of the secondary containment liner beneath them.

[32] *Means Site Work and Landscape Cost Data*, 11th Edition, R.S. Means Co..

EXHIBIT 4-16

COMPARATIVE COST ANALYSIS OF LINER MATERIALS BY MODEL FACILITY[a]

MODEL FACILITY[b]	ESTIMATED LINER CAPITAL COSTS PER MODEL FACILITY[c]						
	IMPERVIOUS SOIL		CONCRETE		GEOMEMBRANES		
	Native Silty Clay	Modified Soil	Uncoated	Coated	Polymeric Sheets	Bentonite Mat	Polysulfide Spray On
#1 New Facility	$5,000	$5,000	$3,000	$8,000	$4,000	$4,000	$5,000
Existing Facility	$6,000	$5,000	$4,000	$9,000	$7,000	$4,000	$5,000
#2 New Facility	$11,000	$9,000	$9,000	$22,000	$13,000	$9,000	$12,000
Existing Facility	$15,000	$11,000	$11,000	$24,000	$18,000	$12,000	$14,000
#3 New Facility	$18,000	$16,000	$17,000	$28,000	$20,000	$17,000	$19,000
Existing Facility[d]	$38,000	$36,000	$36,000	$56,000	$42,000	$36,000	$39,000
#4 New Facility	$28,000	$24,000	$25,000	$47,000	$33,000	$25,000	$31,000
Existing Facility[e]	$50,000	$43,000	$43,000	$66,000	$56,000	$43,000	$48,000
#5 New Facility	$63,000	$64,000	$84,000	$141,000	$95,000	$70,000	$97,000
Existing Facility[f]	$117,000	$116,000	$134,000	$191,000	$150,000	$121,000	$147,000
#6 New Facility	$1,606,000	$1,568,000	$2,304,000	$4,140,000	$2,103,000	$1,894,000	$2,575,000
Existing Facility[g]	$3,404,000	$3,283,000	$3,930,000	$5,767,000	$3,807,000	$3,569,000	$4,186,000

a/ In 1991 dollars.
b/ The six "model" facilities are summarized in Exhibit 4-7.
c/ 30-percent contingency included.
d/ $27,000 of cost is for double bottom tank retrofit for three 10-foot diameter tanks.
e/ $23,000 of cost is for double bottom tank retrofit for two 12-foot diameter tanks.
f/ $81,000 of cost is for double bottom tank retrofit for three 12-foot diameter tanks and double bottom tank retrofit for one 40-foot diameter tank.
g/ $2,534,000 of cost is for double bottom tank retrofit for two 80-foot diameter, three 120-foot diameter, and four 200-foot diameter tanks.

Note: The retrofit costs for Model Facilities 1 and 2 do not include double bottom retrofit costs because the tanks at these model facilities are horizontal, saddle-mounted tanks (see Exhibits 4-1 and 4-2).

EXHIBIT 4-17
ANNUAL OPERATIONS AND MAINTENANCE COSTS

TYPE	IMPERVIOUS SOIL		CONCRETE		GEOMEMBRANES		
	Native Silty Clay	Modified Soil	Uncoated	Coated	Polymeric Sheets	Bentonite Mat	Polysulfide Spray On
Operational	Low	Low	Moderate	Low	Low	Low to High	Low
Liner System Repair	Low	Low	Moderate	High	High	Moderate	High

- Retrofitting of double bottoms occurs during a routine inspection and maintenance period when the tank has been drained, cleaned, and temporarily taken out of service.

- Soils with high permeability can be modified to produce an impervious soil liner by applying 3 pounds of bentonite to each square foot of soil. The liner is covered with 6 inches of soil that is seeded with grass, fertilized, and mulched.

- Tank foundation liners are installed at new, large and medium sized facilities. This involves installation of a HDPE liner, a 2-inch sand layer, cathodic protection, and an additional 2-inch sand layer. At existing facilities, additional equipment such as cranes and temporary tank pads are required for retrofitting undertank liners.

- Large facilities have roads within secondary containment structures. Crushed stone roads are constructed over a liner system consisting of a geomembrane and impervious soil layers. In the case of concrete liners, the concrete is thickened along the course of the road.

As indicated in Exhibit 4-16, for all liner systems, the cost to retrofit liners is higher than installing liners at new facilities because of the added difficulty and cost associated with working around existing tanks and appurtenances (e.g., piping). In addition, certain general conclusions are apparent from the table:

- Coated concrete was the most expensive alternative for all model facilities.

- Uncoated concrete, impervious modified soil, bentonite mat, and polysulfide spray-on liner systems were the least costly for retrofitting of existing facilities with total storage capacities of less than approximately 100,000 gallons.

- For a large facility (e.g., total storage capacity of greater than or equal to 1 million gallons), native soil and bentonite mat liner systems were the least costly alternatives.

- For all model facilities, the bentonite mat liner system was consistently one of the least expensive alternatives.

- For all model facilities, the costs for polymeric sheet liner systems were similar to the costs of other options; however, polymeric sheets were never the least expensive alternative.

A range of costs (expressed in dollars per gallon of storage capacity) to install new and retrofitted liners at the six model facilities is presented in Exhibit 4-18. These ranges are based on the least and most expensive liner cost estimates presented in Exhibit 4-16. Generally, the larger the facility, the lower the price per gallon of capacity to construct a liner system because, for most secondary containment structures of typical proportions, the volume of the secondary containment structure increases at a faster rate than its area. Because secondary containment structures are designed to hold the entire contents of the largest tank or aggregate volume of tanks permanently manifolded together within the structure, the volume of the structure is typically roughly equivalent to the storage capacity of the tank or tanks within that structure. Because the increase in surface area results in costs roughly equivalent to the incremental material and installation cost of liners (which cover the surface area of the secondary containment) and the increase in volume corresponds with the additional amount of available storage capacity, the ratio of available storage volume to surface area increases with tank size. This, in turn, translates into declining cost per gallon of storage capacity. For example, if two facilities have secondary containment areas of 50,000 square feet, and one has a dike height 6 inches higher than the other, the difference in height would add very little to the cost of installing a liner (the increase in lined surface area would be approximately 45 to 50 square yards), but the facility could store as much as 180,000 more gallons of oil.

As shown in Exhibit 4-18, the cost for installing a liner system at an AST with a nominal capacity at a small end-user facility (Model Facility 1) is estimated to range from $1.50 to $4.50 per gallon of storage capacity. A liner system at a large oil terminal facility (Model Facility 6) is estimated to cost approximately $0.03 to $0.11 per gallon of capacity. In general, the costs to install liner systems at facilities would be better represented in dollars per gallon of throughput rather than dollars per gallon of storage capacity since throughput is a better representation of the economical value of the tank; however, EPA lacks sufficient data on average throughput to present costs in this manner.

Existing ASTs are assumed to be retrofitted with double bottoms to prevent undertank discharges. The cost of retrofitting ASTs with double bottoms is proportional to the area of the tank bottom. These retrofits were found to vary from $15 to $115 per

EXHIBIT 4-18

ESTIMATED LINER CAPITAL COST PER GALLON OF STORAGE CAPACITY

MODEL FACILITY	COST FOR RETROFIT INSTALLATION (DOLLARS/GALLON)		COST FOR NEW INSTALLATION (DOLLARS/GALLON)	
	Low	High	Low	High
1	$2.00	$4.50	$1.50	$4.00
2	$0.46	$1.00	$0.38	$0.92
3	$0.80	$1.24	$0.36	$0.62
4	$0.41	$0.63	$0.23	$0.45
5	$0.36	$0.59	$0.19	$0.43
6	$0.07	$0.11	$0.03	$0.08

square foot, depending on the tank size, with the higher cost per square foot associated with smaller tanks. New installations of undertank liners can be completed for approximately $4 to $34 per square foot, depending on tank size.

Annual O&M costs were examined qualitatively in the analysis. They are generally low for impervious soils and geomembrane liners (except for bentonite mats, which must be hydrated regularly). Operational costs for coated concrete are lower than uncoated concrete; however, the costs to repair cracks, deteriorated expansion joints, and sealants for coated concrete systems are greater. Although liner manufacturers rated operational costs for bentonite mats as low, facility owners and operators who had installed these types of liners stated that the operating costs were high. Exposed geomembrane liners are susceptible to damage from vandalism and accidents, and any needed repairs may be costly.

EPA determined that there is not sufficient information to quantify the number, size, and costs associated with releases that liner usage may prevent. However, initial research does indicate that the cost of remediating oil releases will vary greatly depending on the characteristics of the oil (e.g., viscosity), characteristics of the soil and ground-water (e.g., depth to ground water, velocity of flow, depth of saturation, and effects from nearby pumping), external factors such as weather, and remediation technique used. Preliminary analysis suggest that remediation costs can range up to greater than $100 per gallon of oil released.

4.5 LEAK DETECTION METHODS

Current technology has produced a variety of leak detection systems including alarms, inventory control, acoustic emissions testing, volumetric measurement, and interstitial space monitoring, and industry is aggressively developing technology to make leak detection more reliable. EPA has found that leak detection systems are part of an effective liner system for ASTs, serving to bring a leak or spill to the owner's or operator's attention while the liner prevents leaks and spills from reaching soil or ground water.

Leak detection methods are typically classified as either continuous or periodic systems, although many current technologies may be configured to provide either type of operation. Continuous leak detection provides uninterrupted monitoring and, consequently, instant notification of tank failure or an oil discharge. Examples of continuous systems are overfill alarms, overfill sumps, tell-tale drains, interstitial space monitors, and horizontal wells with electronic fluid-flow indicators. These systems are most effective in preventing adverse environmental impacts of discharges when integrated with leak *containment* systems because leak detection systems by themselves only alert facility operators to the existence of the discharge. For example, when used in conjunction with double tank bottoms, interstitial space monitoring may consist of a hydrocarbon sensitive tape lying between a tank's external bottom and its internal double bottom. Use of tell-tale drains on ASTs also is common at facilities that have installed double bottom retrofits. Tell-tale drains are used to check the integrity of the double bottom by providing a drain path for any liquid that has accumulated in the space between the two bottoms. While overfill alarms and sumps are a form of leak detection, they do not provide notification of tank bottom failure.

Periodic leak detection involves checks or tests at regular intervals to determine the occurrence of oil discharges or tank bottom failure. The type of system used generally depends on the type and size of the tank being monitored. Periodic systems include: internal/external visual inspections; pressure/vacuum testing of tanks and piping; volumetric precision testing of the tank; inventory record and measurement reconciliation; acoustic emissions testing; and chemical gas detection methods. OSCs agreed that visual inspection is the most common form of leak detection at AST facilities. When visual leak detection is used, daily records need to be maintained, interpreted, and reviewed to provide the most sensitive leak detection threshold possible. The most significant drawback to visually inspecting vertically mounted tanks is the inability to examine the tank bottom while the tank is in service.

Periodic leak detection systems are generally required in States that regulate ASTs; however, these methods are not adequate in certain situations. For example, visual inspections cannot be conducted for the bottom or internal area of vertical ASTs without the removal of stored product. In such circumstances, other non-invasive periodic methods (i.e., those that do not require tank entry) such as acoustic emissions

testing and precision volumetric detection, must be used. These methods can have detection thresholds as low as one gallon of leaking product per hour.

Intrusive methods of leak detection have an extremely high detectability rate because areas that are suspected to have failed can be examined by other means of integrity testing (i.e., ultrasonic, radiographic, dye penetrant, magnetic particle, and vacuum box testing). Internal inspections can be expensive and result in significant tank down-time; consequently, intervals between tests have historically been as long as 20 years. Internal inspections alone may not be adequate to identify tank bottom failures because of the long time between bottom failure and leak discovery given the average time between tests.

Other non-invasive methods of leak detection such as inventory reconciliation can be useful at detecting large leaks; however, inventory checks may not detect slow, continuous leaks because of the normal margin of error in making measurements and the effects of temperature-related expansion of product volume in the tank. Although the types of systems described in the paragraphs above are effective for detection of smaller leaks, their expense can be significant.

5. RECOMMENDATIONS

This chapter presents the Agency's recommendations. The recommendation of this Report to Congress is based primarily on the results of EPA's study of liners as well as insights the Agency has gained over the past 20 years into the problems posed by onshore AST facilities. As a first step toward addressing the potential risks to public health and the environment as a result of contamination from AST facilities located near navigable waters, the Agency recommends initiating, through a *Federal Register* notice or stakeholder workgroups, a process involving broad public participation to develop a voluntary program. This process would give stakeholders the opportunity to share new or additional data and information to characterize the sources, causes, and extent of soil and ground-water contamination and efforts underway to address contamination at AST facilities nationwide. Such data are critical to determining the most appropriate and effective means to reduce contamination.

As envisioned by EPA, the voluntary program would be designed to encourage facility owners or operators, through incentives such as technical assistance, cost savings, and public recognition, to identify and report contamination, take actions to prevent leaks and spills, and remediate soil and ground-water contamination. This program would complement the Agency's efforts to develop cleaner, cheaper, and smarter approaches to environmental problems through innovative solutions that depart from the traditional regulatory approach. The Agency favors a voluntary, rather than regulatory, approach at this time in order to provide greater flexibility in addressing contamination at the vast range of oil storage facility types, sizes, and locations. A voluntary program could focus more directly on facilities that may pose the greatest hazard to public health and the environment. For example, the program may initially focus on larger, older facilities, and facilities located near waters, sensitive areas, or populations. In addition, a voluntary approach could allow implementation of the most appropriate prevention and cleanup activities for each facility. The program would look for incentives for industry to implement reasonable and cost-effective measures to address existing problems and help prevent future ones.

EPA views such a program as a cooperative effort among EPA, State governments, industry, and environmental groups. Based on this study's findings, EPA believes the program should include commitments from facilities to:

- Address known contamination and to assure that existing contamination will not be allowed to migrate offsite;
- Report to appropriate government agencies the status of facility contamination and actions underway to address any problems;

- Adopt the most protective appropriate prevention standards and upgrade equipment as necessary; and

- Monitor and/or implement leak detection to ensure that new leaks are addressed.

Provided stakeholders commit to the voluntary approach, a successful program will entail the identification of specific actions for participating facilities to undertake and include means for objectively measuring results.

EPA has evaluated the feasibility of conducting a voluntary program to address the problem of AST releases and concluded that a voluntary program is worth pursuing for the following reasons:

- The universe of large AST facilities is relatively easy to define and is represented by several large trade associations.

- The program is consistent with the Agency's goal of developing and promoting innovative approaches to achieve environmental goals.

- Clear, achievable goals are apparent (e.g., to mitigate the spread of existing contamination and to prevent future releases).

- Flexible approaches (i.e., numerous technological options and management practices) are available to address the problem, thus allowing participants to implement the program in a tailored manner appropriate to their circumstances.

- EPA is committed to providing technical assistance as well as other incentives.

- There are established industry and state practices and standards that can be used as a basis for constructing a comprehensive program.

EPA identified several characteristics shared by successful voluntary programs. These include:

- The program must have goals that are clearly defined up front – This assures that participants are working toward the same objectives and provides a framework that increases efficiency.

- The program must have achievable goals – The goals of the program must be realistic in order to ensure widespread participation and avoid wasting resources.

- The program must offer useful incentives – Successful voluntary programs offer benefits to attract and maintain the interest of participants. Such incentives have included:

  - Cost savings/long-term profits/more efficient operations (release prevention reduces product loss);
  - Publicity (newsletters, press releases, etc.);
  - Recognition (certificates of participation and achievement);
  - Technical assistance (advice and sources of information);
  - Reducing or eliminating the need for regulations; and
  - Other types of assistance, such as assistance in identifying Federal/State/private financial options (i.e., information on insurance programs, State grant programs, etc.).

  EPA will vigorously pursue other incentives, and will work with interested parties over the coming months to help identify them.

- The program must have a structure in place to work with all potentially affected and interested parties and promote continued participation – We believe it is imperative that a voluntary program ensure broad participation and be structured so that all involved can affect the decision-making process.

- The program must effectively track progress and disseminate success stories – Project tracking enables the Agency to determine whether the program is successful, identify areas where adjustments are needed, resolve issues, and plan future goals. Success stories help foster new involvement.

- The program must have the support of the lead agency, the public, and participants – For a program to be successful, it needs a real and strong commitment of those involved.

In keeping with the Agency's initiatives to develop innovative, common-sense approaches to environmental problems, EPA supports a voluntary prevention and cleanup program as a first step in addressing the environmental problem presented by contamination from AST facilities. Industry representatives have expressed their support for such a program as a more cost-effective, flexible alternative than traditional regulation. EPA fully supports such an attempt, and believes it will be successful, provided that it has the full commitment of those involved. The Agency believes it is essential that stakeholders have the opportunity to participate in the development and execution of this voluntary program and will establish an open process for public input into the program's design and implementation.

REFERENCES

American Petroleum Institute (API), "Aboveground Storage Tank Survey," prepared by Entropy Limited, April 1989.

American Petroleum Institute (API), "A Survey of API Members' Aboveground Storage Tank Facilities," prepared by API Health and Environmental Affairs Department, July 1994.

American Petroleum Institute (API), "Welded Steel Tanks for Oil Storage," API Standard 650, July 1993.

Means Site Work and Landscape Cost Data, 11th Edition, R.S. Means Co., 1991.

National Fire Protection Association (NFPA), Flammable and Combustible Liquids Code (NFPA 30) Section 2-2.3.3, 1993 edition.

New York State Department of Environmental Conservation, (NYDEC Database).

Office of Management and Budget Circular No. A-94 (57 FR 53519).

Suffolk County Department of Health Services, "Final Report: Tank Corrosion Study," 1988.

U.S. Coast Guard and U.S. Department of Transportation, "Control of Pollution by Oil and Hazardous Substances, Discharge Removal," 33 CFR part 153, 7-1-93 edition.

U.S. Environmental Protection Agency, "Discharge of Oil," 40 CFR part 153, 7-1-93 edition.

U.S. Environmental Protection Agency, Emergency Response Division, "Estimate of the Number of Aboveground Storage Tanks at Onshore Facilities," October 1994.

U.S. Environmental Protection Agency, Emergency Response Division, "Investigating the Risk Posed by Different Sizes of Facilities Potentially Regulated by the Oil Pollution Prevention Regulation," May 1993.

U.S. Environmental Protection Agency, Emergency Response Division, "Regulatory Impact Analysis of Revisions to the Oil Pollution Prevention Regulation," Draft Report, 1991.

U.S. Environmental Protection Agency, Emergency Response Division, "Regulatory Impact Analysis of Revisions to the Oil Pollution Prevention Regulation (40 CFR 112) to Implement the Facility Response Planning Requirements of the Oil Pollution Act of 1990," June 1994.

U.S. Environmental Protection Agency, Emergency Response Division, "Spill Prevention, Control, and Countermeasures Facilities Study," January 1991.

U.S. Environmental Protection Agency, Emergency Response Notification System, (ERNS Database).

U.S. Environmental Protection Agency, "Oil Pollution Prevention," 40 CFR part 112, 7-1-93 edition.

U.S. Environmental Protection Agency, "Oil Pollution Prevention; Non-Transportation-Related Onshore Facilities," 58 FR 8824, February 17, 1993.

U.S. Environmental Protection Agency, "Standards for Owners and Operators of Hazardous Waste Treatment, Storage, and Disposal Facilities," 40 CFR part 264, 7-1-93 edition.

U.S. Environmental Protection Agency, "Technical Standards and Corrective Action Requirements for Owners and Operators of Underground Storage Tanks (USTs)," 40 CFR part 280, 7-1-93 edition.

Virginia Department of Environmental Quality (VADEQ), "The Virginia DEQ Aboveground Storage Tank Regulations," April 4, 1994.

Virginia Regulation 680-14-12: Facility and AST Registration Requirements, effective September 22, 1993.

"World Spill Briefs," *Golub's Oil Pollution Bulletin*, Vol. 5 No. 12, May 1993, p. 7.

APPENDIX A: STATE REGULATIONS

EPA reviewed current and proposed AST regulations for the 50 States to gather information on liner systems and to estimate the number of facilities currently required to use liners as a result of State regulation. Exhibit A-1 summarizes the results of this review. The following components of AST regulatory programs were examined:

- Status of AST requirements (i.e., full AST regulations, NFPA or other fire codes only, proposed AST regulations with NFPA or other fire codes, or proposed AST regulations only);
- Status of liner requirements (current, proposed, or none);
- Status of spill data collection (full AST regulations, some spill data collection, AST data base started but is not extensive or easy to access, or spill data collected but not required by regulation); and
- Whether a cost/benefit data analysis was performed.

Section 3.1.2 provides a more detailed discussion of the nine States (AK, CO, FL, MO, NJ, NY, RI, SD, and WI) that have promulgated or proposed regulations specifying the use of "impermeable" secondary containment systems, liners, or other diversionary structures and systems.

EXHIBIT A-1

STATE REGULATIONS[33]

STATE	BASIS FOR AST REQUIRE-MENTS	LINER REQUIREMENT		Spill Data Collected	Cost/Benefit Data	Comments
		Current	Proposed			
Alabama	1			Some		Guidelines available
Alaska	X	X		★		Liners required at new facilities only
Arizona	1					
Arkansas	X					Working on draft regulations
California	X			★		
Colorado	• 1					Proposed AST regulations
Connecticut	• 1		X	★		Proposed AST regulations
Delaware	1			Some		
Florida	X	X		X	X	
Georgia	1					
Hawaii	1			Some		
Idaho	1			●		
Illinois	1					
Indiana	1					
Iowa	1			★		
Kansas	1					
Kentucky	1			★		Began data base in '92; no regulations; local control
Louisiana	1					

[33] Information as of April 1994.

LEGEND

X = AST regulation
1 = NFPA or other fire codes
★ = data base started, but not extensive nor easy to access
o = spill data is collected, but not required by regulation
• = proposed AST regulation

STATE	BASIS FOR AST REQUIRE-MENTS	LINER REQUIREMENT		Spill Data Collected	Cost/Benefit Data	Comments
		Current	Proposed			
Maine	1			o		Some oil terminal regulations; proposed AST regulations currently under development
Maryland	X	X		X	X	
Massachusetts	X			X		Regulations only cover tanks > 10,000 gallons
Michigan	1			★		No regulations; local control
Minnesota	X			X	X	Cost/benefit data from the failed liner requirement available
Mississippi	1					
Missouri	1					
Montana	1					
Nebraska	1					Requires liners on a case by case basis
Nevada	1					
New Hampshire	1			★		
New Jersey	X	X		X		
New Mexico	1					No regulations; local control
New York	X	X		X	X	
North Carolina	1			o		
North Dakota	1			o		
Ohio	1			o		Proposed regulations currently under development; no provisions available
Oklahoma	1					
Oregon	1			o		
Pennsylvania	X			★		New and retrofit must meet API standards

LEGEND

X = AST regulation
1 = NFPA or other fire codes
● = data base started, but not extensive nor easy to access
o = spill data is collected, but not required by regulation
• = proposed AST regulation

STATE	BASIS FOR AST REQUIRE-MENTS	LINER REQUIREMENT		Spill Data Collected	Cost/Benefit Data	Comments
		Current	Proposed			
Rhode Island	X	X		X		
South Carolina	1			o		
South Dakota	X	X				
Tennessee	1					No regulations; local control
Texas	X					
Utah	1					
Vermont	1			•		
Virginia	X					Regulation applies to facilities with AST capacity in excess of 25,000 gallons of oil. Requires installation of release prevention barriers either under or in the bottom of new or retrofitted tanks.
Washington	X					Only covers marine terminals
West Virginia	1					
Wisconsin	X	X				
Wyoming	1			•		

LEGEND

X = AST regulation
1 = NFPA or other fire codes
★ = data base started, but not extensive nor easy to access
o = spill data is collected, but not required by regulation
• = proposed AST regulation

APPENDIX B: MODEL FACILITIES

This appendix describes how EPA used previous analyses to determine how the model facilities developed for this analysis would represent the diversity of facilities with ASTs that do not have liner systems in place.

B.1 Allocation of AST Facilities into Size and Use Categories

As described in Chapter 2, the universe of AST facilities that currently is estimated not to have liners was divided into size categories based on their storage capacity and use categories (see Exhibit 2-6). This classification scheme has been used in a previous EPA analysis supporting revisions to the Oil Pollution Prevention regulation.[34] EPA's earlier analysis also estimated the storage capacity for typical (i.e., representative) facilities in eight of the nine size and use categories. (Because only a negligible number of large facilities were estimated to exist, no typical storage capacity was estimated for this category.) The results of the analysis are presented in Exhibit B-1.

EXHIBIT B-1

TYPICAL STORAGE CAPACITIES FOR FACILITIES FROM PREVIOUS EPA ANALYSIS

Size and Use Category	Production	Storage/Distribution	Storage/Consumption
Small	37,800 gallons	10,000 gallons	2,000 gallons
Medium	96,600 gallons	250,000 gallons	205,000 gallons
Large	Not Applicable	21,400,000 gallons	4,028,000 gallons

To ensure consistency in its analyses, EPA used the typical storage capacities from this earlier analysis to determine which model facilities developed in this analysis best represented each size and use category. Specifically, EPA compared the typical storage capacities used in the previous analysis (and presented in Exhibit B-1) with the assumed storage capacities of the model facilities developed for this report. If a single model facility from this report closely agreed with the storage capacity from the earlier analysis, then that model facility was assumed to represent all of the AST facilities that currently do not have liners in that size and use category (as presented in Exhibit 2-6). For

[34] U.S. EPA, Emergency Response Division, "Regulatory Impact Analysis of Revisions to the Oil Pollution Prevention Regulation (40 CFR 112) to Implement the Facility Response Planning Requirements of the Oil Pollution Act of 1990", June 1994.

example, Model Facility 1 has an assumed storage capacity of 2,000 gallons, which equals the typical storage capacity of small storage/consumption facilities from EPA's earlier analysis. Consequently, all 198,529 small storage/consumption facilities are considered to be represented by Model Facility 1.

Where the typical storage capacity of facilities in a size and use category did not closely agree with a single model facility from this report, two model facilities were used to represent that size and use category. The allocation of facilities between the two model facilities generally was based on the difference between the typical storage category, as presented in Exhibit B-1, and the assumed storage capacities of the model facilities. For example, small storage/distribution facilities are estimated to typically have a total storage capacity of approximately 10,000 gallons, for which no single model facility in this report corresponds closely. Therefore, small storage/distribution facilities are best represented by a mix of Model Facilities 1 and 2, which are assumed to have 2,000 and 24,000 gallons of storage capacity, respectively. As the "typical" small storage/distribution facility (10,000 gallons) is closer in storage capacity to that of Model Facility 1 (2,000 gallons) than Model Facility 2 (24,000 gallons), facilities were allocated disproportionately to Model Facility 1. Of the estimated 4,554 small storage/distribution facilities, 2,898 facilities are estimated to be best represented by Model Facility 1, and the remaining 1,656 facilities are estimated to be best represented by Model Facility 2. The model facilities selected to represent each size and use category and the allocation ratios are presented in Exhibit B-2.

EXHIBIT B-2

CATEGORIZATION OF FACILITIES NOT CURRENTLY REQUIRED TO INSTALL LINERS

Size and Use Category	Production	Storage/Distribution	Storage/Consumption
Small	Model Facility 2 (34%) Model Facility 3 (66%)	Model Facility 1 (64%) Model Facility 2 (36%)	Model Facility 1 (100%)
Medium	Model Facility 4 (100%)	Model Facility 3 (41%) Model Facility 5 (59%)	Model Facility 4 (54%) Model Facility 5 (46%)
Large	Not Applicable	Model Facility 6 (100%)	

In the case of medium storage/distribution facilities, however, an alternative formula was used. The medium storage/distribution category of facilities includes gasoline service stations with ASTs. Historically, most gasoline service stations stored product in USTs; however, where land limitations require or building codes allow, ASTs

are used at these facilities for product storage. Model 3, with a storage capacity of 45,000 gallons, is an effective representation of such medium-sized gasoline service stations. As shown in Exhibit 3-2, there are an estimated 5,967 medium-sized gasoline service stations. Therefore, 5,967 of the 14,681 medium storage/distribution facilities are represented by Model 3, and the remaining 8,714 are represented by Model 5, whose assumed storage capacity of 325,000 gallons is closest to the typical storage capacity of facilities in this size and use category (i.e., 250,000 gallons).

To determine the total number of facilities that each model facility represents, the percentages in Exhibit B-2 were multiplied by the estimated number of AST facilities in the corresponding size and use category in Exhibit 2-6 and the amounts were summed by model facility:

• Model Facility 1:	201,427	2,898 small storage/distribution facilities All small storage/consumption facilities
• Model Facility 2:	49,296	1,656 small storage/distribution facilities 47,640 small production facilities
• Model Facility 3:	97,277	91,310 small production facilities 5,967 medium storage/distribution facilities
• Model Facility 4:	55,623	All medium production facilities 5,880 medium storage/consumption facilities
• Model Facility 5:	13,663	8,714 medium storage/distribution facilities 4,949 medium storage/consumption facilities
• Model Facility 6:	3,927	All large storage/consumption facilities
	421,213 facilities	

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C. 20460

JUL 14 2000

OFFICE OF
SOLID WASTE AND EMERGENCY
RESPONSE

Mr. Chris Early
Safety-Kleen Corporation
1301 Gervais Street
Columbia, SC 29201

Dear Mr. Early:

Thank you for your e-mail of May 31, 2000. Through this letter, we respond to the questions you posed in your e-mail.

Your first set of questions concerned the meaning of the terms "transportation-related" and "non-transportation-related" as they relate to SPCC facilities. You also raised issues concerning transfers of oil in the first set of questions. You posed the fact situation of "a rail car containing oil that enters my site by crossing site boundaries." You added that the "rail car is one of many rail cars and is the only rail car containing oil." We will repeat your questions, and answer them immediately below. We note that we have coordinated our response with the U.S. Department of Transportation (DOT).

1. **Question:** "If the rail car is passing through my facility and the oil contained in this rail car is not loaded or unloaded is it subject to the SPCC requirements including SPCC Plan and containment system/diversionary structure or proof of impracticability requirements? Or, is this rail car subject to DOT requirements because it is considered as a transportation-related unit?"

Answer: As a general rule, we will presume that the rail car is considered to be a "transportation-related facility" under the 1971 Memorandum of Understanding (MOU) between DOT and the U.S. Environmental Protection Agency (EPA) if it is consigned to your property or is consigned elsewhere and is being stored incidental to transportation in commerce. Storage incidental to transportation in commerce is storage between the time the oil is offered for transportation to a carrier until the time that it reaches its destination and is accepted by the consignee, assuming no circumstances marking an end to the transportation process. EPA will consider all the circumstances concerning the presence of the rail car at the facility before determining that there has been an end to the transportation process and a beginning of non-transportation-related storage subject to SPCC requirements. If non-transportation-related storage has begun, the rail car will be subject to SPCC requirements if it contains above the regulatory threshold

Recycled/Recyclable
Printed with Soy/Canola Ink on paper that contains at least 50% recycled fiber

amount and there is a reasonable possibility of discharge from the rail car to navigable waters or adjoining shorelines. If the rail car is consigned to the Safety-Kleen facility, as indicated on shipping papers, bills of lading, or other shipping documentation, then transportation of the rail car ends once it arrives at the facility, and the rail car is subject to SPCC requirements. However, if the rail car is consigned to a different facility and is merely passing through the Safety-Kleen facility on its way to its consigned destination with no unreasonable delays, then the rail car is considered to be in storage incidental to transportation in commerce and is not subject to SPCC requirements. Instead the car is subject to applicable DOT requirements for the duration of such transportation.

2. **Question:** "If this rail car stops on my property for any period of time but the oil in the rail car is never loaded or unloaded is it subject to SPCC requirements at any time including SPCC Plan and containment system/diversionary structure or proof of impracticability requirements?"

Answer: See the answer to Question 1 above.

3. **Question:** "If the rail car is loaded or unloaded at any time is it subject to SPCC Plan and containment system/diversionary structure or proof of impracticability requirements?"

Answer: The loading or unloading of the rail car may mark an end to the transportation process and the beginning of non-transportation-related storage, triggering all SPCC requirements, assuming that the rail car stores oil in an amount above the regulatory threshold and that there is a reasonable possibility of discharge to navigable waters or adjoining shorelines. In this case, the rail car itself may become the non-transportation-related facility even if no other containers at the property would qualify the property as a non-transportation-related facility.

4. **Question:** "If the rail car is loaded/unloaded intermittently (i.e., over a period of 14 days oil in the rail car is unloaded on two consecutive Mondays) is the rail car subject to SPCC requirements only during the loading events including SPCC Plan and containment system/diversionary structure or proof of impracticability requirements?"

Answer: The loading or unloading of the rail car, whether intermittent or not, may mark an end to the transportation process and the beginning of non-transportation-related storage, triggering all SPCC requirements, assuming that the rail car stores oil in an amount above the regulatory threshold and that there is a reasonable possibility of discharge to navigable waters or adjoining shorelines. In this case, the rail car itself may become the non-transportation-related facility even if no other containers at the property would qualify the property as a non-transportation-related facility.

5. **Question:** "If the rail car enters my site (1/3 crosses the facility boundaries), is any portion of the rail car subject to SPCC Plan requirements including SPCC Plan and

containment system/diversionary structure or proof of impracticability requirements?"

Answer: If by entry on the site, the rail car has reached its ultimate destination, then the transportation process has ended and non-transportation-related storage has begun, triggering all SPCC requirements, assuming that the rail car stores oil in an amount above the regulatory threshold and that there is a reasonable possibility of discharge to navigable waters or adjoining shorelines. In this case, the rail car itself becomes the non-transportation-related facility even if no other containers at the property would qualify the property as a non-transportation-related facility.

Your second set of questions posited the fact situation that you demonstrate in your SPCC Plan that it is impracticable to provide containment systems/diversionary structures and instead provide a strong oil contingency plan.

1. **Question:** "Does the word 'demonstrate' used here indicate that the SPCC Plan will only require certification by a Registered Professional Engineer no matter the reason used to determine impracticability?"

Answer: The owner or operator of the facility must demonstrate impracticability if he cannot provide secondary containment. The Professional Engineer must certify that demonstration of impracticability. If the Regional Administrator disagrees with the owner or operator's determination, he may require that the owner or operator amend his Plan.

2. **Question:** "In developing a strong Oil Contingency Plan who determines if the plan is 'strong' enough to respond and prevent released oil from reaching navigable water?"

Answer: The owner or operator of the facility must determine that the Contingency Plan is adequate to meet regulatory requirements. The Professional Engineer must certify that determination. If the Regional Administrator disagrees with the owner or operator's determination, he may require that the owner or operator amend his Plan.

Your third set of questions asked "at what point the following transportation-related facility units become non-transportation related and subject to SPCC requirements."

a. **Question:** "Rail car"

Answer: A rail car may or may not be transportation-related, depending on the use to which it is put. See the 1971 MOU, § II(1)(F), (1)(J), and (2)(D).

b. **Question:** "Any vehicle with oil capacity of 660 gallons."

Answer: A vehicle may or may not be transportation-related, depending on the use to

which it is put. See the 1971 MOU, § II(1)(F), (1)(J), and (2)(D).

Again, thank you for your e-mail. Should you have any questions concerning this letter, please contact Hugo Fleischman of my staff at 703-603-8769. Please do not hesitate to contact us again should you have other questions.

Sincerely,

David Lopez, Director
Oil Program Center

cc: Susan Gorsky, DOT

4

Melissa Young, Esq.
Government Affairs Counsel
Petroleum Marketers Association of America
1901 N. Fort Meyer Drive
Suite 1200
Arlington, Virginia 22209-1604

Dear Ms. Young:

Thank you for your letter to Administrator Whitman of February 5, 2001, which she has referred to me for an answer.

You explained that a marketer was notified by an Environmental Protection Agency (EPA) inspector that her facility, which is below the 42,000 gallon underground storage tank threshold capacity, would need a Spill Prevention, Control, and Countermeasure (SPCC) Plan, because she parks her 2,500 gallon cargo tank motor vehicle at the facility in the evenings. You noted that it is used to deliver petroleum products in commerce, not as a mobile fueling facility and that it is emptied before it is parked for the evening.

EPA presumes that a cargo tank motor vehicle that contains no oil, other than any residual oil present in an emptied vehicle when it is parked at the facility in the evening, is a highway vehicle used for the transport of oil in interstate or intrastate commerce, and is therefore transportation-related, and not subject to SPCC jurisdiction. 40 CFR 112, Appendix A, Section II(2)(D). You should be aware, however, if the vehicle were to be used at any time in a fixed operating non-transportation mode, such as the storage or transfer of oil in any amount, other than any residual oil present in an emptied vehicle at the end of the day, then it would become subject to the SPCC rule if there were a reasonable possibility of discharge from the vehicle to navigable waters or adjoining shorelines. See 40 CFR 112.3(c); and 40 CFR 112, Appendix A, Section II(1)(F).

To determine if a fixed operating non-transportation mode has begun, and therefore EPA SPCC jurisdiction arises, an EPA inspector would will look at all the circumstances at a particular facility. Here, such circumstances might include whether the vehicle is functioning as a storage tank, supplementing storage capacity or transferring oil at the facility. We believe the vehicle you described is operating in a transportation-related

mode, and therefore, no EPA SPCC regulatory jurisdiction arises. We note that if the vehicle itself were to be subject to the SPCC rule, it exceeds the SPCC regulatory threshold regardless of any other storage or use of oil at the facility. We also note that if it is used for the transport of oil exclusively within the confines of a facility and is not intended to transport oil in interstate or intrastate commerce, it may be subject to the SPCC rule. 40 CFR 112, Appendix A, Section II(1)(J).

Again, thank you for your letter. Please do not hesitate to contact us again if you have other questions concerning EPA's oil program. If you have any questions about this letter, please contact Hugo Fleischman at 703-603-8769 or Mark Howard at 703-603-8715.

Sincerely,

Stephen F. Heare, Acting Deputy Director,
Office of Emergency and Remedial Response

cc: Clifford J. Harvison, NTTC
James Malcolm, MC 2131
Susan Gorsky, DOT

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C. 20460

AUG - 9 2002

OFFICE OF
SOLID WASTE AND EMERGENCY
RESPONSE

OSWER 9360.8-38

MEMORANDUM

SUBJECT: Use of Alternative Secondary Containment Measures at Facilities Regulated under the Oil Pollution Prevention Regulation (40 CFR Part 112)

FROM: Marianne Lamont Horinko
Assistant Administrator

TO: Oil National Policy Managers, Regions 1-10

PURPOSE

This memorandum amends the guidance issued on April 29, 1992 (i.e., Use of Alternative Secondary Containment Measures at Facilities Regulated under the Oil Pollution Regulation (40 CFR Part 112), (OSWER 9360.8-37) concerning the potential use of certain double-wall aboveground storage tanks (ASTs) for secondary containment purposes. A copy is attached for your reference. This guidance also clarifies when shop-built double-walled ASTs satisfy the applicable secondary containment requirements in the Spill Prevention, Control, and Countermeasure (SPCC) rule, found at 40 CFR part 112. We take this step because larger shop-built ASTs that use the protective measures described in the 1992 guidance are generally protective of the environment under certain circumstances.

BACKGROUND

On April 29, 1992, EPA issued guidance on how certain shop-built double-wall ASTs may comply with the secondary containment requirements of §112.7(c). The guidance discussed compliance with §112.7(c) only, and did not discuss compliance with other applicable SPCC provisions. We said at the time that "there should be many situations in which protection of navigable waters substantially equivalent to that provided by the secondary containment systems listed in section 112.7(c) could be provided by alternative AST systems that have capacities generally less than 12,000 gallons and are installed and operated with protective measures other than secondary containment dikes."

OSWER 9360.8-38

DISCUSSION

SPCC secondary containment requirements. Section 112.7(c) requires that the owner or operator:

> "Provide appropriate containment and/or diversionary structures or equipment to prevent a discharge as described in §112.1(b). The entire containment system, including walls and floor, must be capable of containing oil and must be constructed so that any discharge from a primary containment system, such as a tank or pipe, will not escape the containment system before cleanup occurs. At a minimum, you must use one of the following preventive systems or its equivalent:
>
> (1) For onshore facilities:
> (i) Dikes, berms or retaining walls sufficiently impervious to contain oil;
> (ii) Curbing;
> (iii) Culverting, gutters or other drainage systems;
> (iv) Weirs, booms or other barriers;
> (v) Spill diversion ponds;
> (vi) Retention ponds; or
> (vii) Sorbent materials.
> (2) For offshore facilities:
> (i) Curbing, drip pans; or
> (ii) Sumps and collection systems."

After nearly a decade of evaluation of the construction, performance, and use of certain shop-built double-wall ASTs, we believe that they may serve as an "equivalent" preventive system for purposes of §112.7(c).

In 1992, we recognized that a shop-built double-wall AST with a capacity "generally less than 12,000 gallons" that was installed and operated with protective measures other than a secondary containment dike might meet the secondary containment requirements of §112.7(c). We described those protective measures as "when the inner tank is an Underwriters' Laboratory-listed steel tank, the outer wall is constructed in accordance with nationally accepted industry standards (e.g., those codified by the American Petroleum Institute, the Steel Tank Institute, and the American Concrete Institute), the tank has overfill prevention measures that include an overfill alarm and an automatic flow restrictor or flow-shutoff, and all product transfers are constantly monitored."

Today, after nearly a decade of experience in which we have seen the construction, performance, and use of shop-built double-wall ASTs, we note a low

OSWER 9360.8-38

occurrence of discharges from such tanks, including tanks with a capacity of 12,000 gallons or more. In some cases, such tanks provide secondary containment where none existed before, or superior environmental protection to alternative containment systems previously used. We believe that a 12,000 gallon limitation on the use of certain shop-built double-wall ASTs is therefore no longer necessary, and believe that shop-built double-wall ASTs that use the protective measures described in 1992 generally satisfy the secondary containment requirements found in §112.7(c).

Bulk storage secondary containment requirements (§112.8(c)(2)); inspection requirements (§112.8(c)(6)). For the same reasons outlined above, we also believe that shop-fabricated double-wall AST, regardless of size, may generally satisfy not only the secondary containment requirements of §112.7(c), but also the bulk storage secondary containment requirements found at §112.8(c)(2). Section 112.8(c)(6) requires the owner or operator to conduct integrity testing on a regular schedule and whenever he makes repairs. The owner or operator must also frequently inspect the outside of the container for signs of deterioration, discharges, or accumulation of oil inside diked areas. To comply with the requirement to frequently inspect the outside of the tank, an owner or operator must inspect the inner wall and interstitial spaces of a shop-built double-wall AST. We recommend the use of automatic detection devices to detect discharges into the interstitial space. Owners or operators should conduct this integrity testing and inspection in accordance with industry standards, when practicable. One industry standard presently available is "SP001-00, Standard for Inspection of In-Service Shop-Fabricated Aboveground Tanks for Storage of Combustible and Flammable Liquids." Other applicable standards may be developed in the future.

Other applicable SPCC requirements. While shop-fabricated double-wall ASTs may satisfy the requirements of §112.7(c) and §112.8(c)(2), such tanks must also continue to satisfy all other applicable SPCC requirements. For example, the facility owner or operator must satisfy §112.7(h) requirements for tank car and tank truck loading/unloading racks if he transfers oil in bulk to those tanks from highway vehicles or railroad cars. If such transfers occur, where loading/unloading area drainage does not flow into a catchment basin or treatment facility designed to handle spills, a quick drainage system must be used. The containment system must be designed to hold at least the maximum capacity of any single compartment of a tank car of tank truck loaded or unloaded at the facility.

Additionally, any piping, equipment, or device not contained within a double-wall AST is subject to the requirements of §112.8(b)(3) and (4), if such piping, equipment, or device is in an undiked area.

CONCLUSION/IMPLEMENTATION Should you have any questions concerning this memorandum, please contact Hugo Fleischman, of my staff, at 703-603-8769.

OSWER 9360.8-38

Attachment

cc: Michael B. Cook
Elaine Davies
Andrew Gordon
David Drelich
Oil Removal Managers
OERR Records Manager, IMC 5202G
OERR Documents Coordinator, HOSC 5202G
Jeff Josephson, Superfund Lead Region Coordinator, USEPA Region 2
NARPM Co-Chairs
Doug Kodama, Oil Lead Region Coordinator, USEPA Region 2

§ 1794.51 Preparation for scoping.

(a) As soon as practicable after RUS and the applicant have developed a schedule for the environmental review process, RUS shall have its notice of intent to prepare an EA or EIS and schedule scoping meetings (§ 1794.13) published in the **Federal Register** (see 40 CFR 1508.22). The applicant shall have published, in a timely manner, a notice similar to RUS' notice.

* * * * *

14. Section 1794.52(d) is amended by removing the last sentence and adding a new sentence at the end of the paragraph to read as follows:

§ 1794.52 Scoping meetings.

* * * * *

(d) * * * The applicant or its consultant shall prepare a record of the scoping meeting. The record shall consist of a transcript when a traditional meeting format is used or a summary report when an open house format is used.

* * * * *

15. Section 1794.53 is revised to read as follows:

§ 1794.53 Environmental report.

(a) After scoping procedures have been completed, RUS shall require the applicant to develop and submit an ER. The ER shall be prepared under the supervision and guidance of RUS staff and RUS shall evaluate and be responsible for the accuracy of all information contained therein.

(b) The applicant's ER will normally serve as the RUS EA. After RUS has reviewed and found the ER to be satisfactory, the applicant shall provide RUS with a sufficient number of copies of the ER to satisfy the RUS distribution plan.

(c) The ER shall include a summary of the construction and operation monitoring and mitigation measures for the proposed action. These measures may be revised as appropriate in response to comments and other information, and shall be incorporated by summary or reference into the FONSI.

16. Section 1794.54 is revised to read as follows:

§ 1794.54 Agency determination.

Following the scoping process and the development of a satisfactory ER by the applicant or its consultant that will serve as the agency's EA, RUS shall determine whether the proposed action is a major Federal action significantly affecting the quality of the human environment. If RUS determines the action is significant, RUS will continue with the procedures in subpart G of this part. If RUS determines the action is not significant, RUS will proceed in accordance with §§ 1794.42 through 1794.44, except that RUS shall have a notice published in the **Federal Register** that announces the availability of the EA and FONSI.

§ 1794.61 [Amended]

17. Section 1794.61 is amended by:

A. Removing paragraph (b).

B. Redesignating paragraph (a) as the introductory text; paragraph (a)(1) as (a); paragraph (a)(2) as (b); and paragraph (a)(3) as (c).

Dated: December 24, 2002.

Blaine D. Stockton,

Acting Administrator, Rural Utilities Service.

[FR Doc. 03–713 Filed 1–14–03; 8:45 am]

BILLING CODE 3410–15–P

DEPARTMENT OF DEFENSE

Department of the Army, Corps of Engineers

33 CFR Part 328

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 110, 112, 116, 117, 122, 230, 232, 300, and 401

[FRL–7439–8]

RIN 2040–AB74

Advance Notice of Proposed Rulemaking on the Clean Water Act Regulatory Definition of ''Waters of the United States''

AGENCIES: U.S. Army Corps of Engineers, Department of the Army, DOD; and Environmental Protection Agency.

ACTION: Advance notice of proposed rulemaking.

SUMMARY: The U.S. Army Corps of Engineers (Corps) and the Environmental Protection Agency (EPA) are today issuing an advance notice of proposed rulemaking (ANPRM) in order to obtain early comment on issues associated with the scope of waters that are subject to the Clean Water Act (CWA), in light of the U.S. Supreme Court decision in *Solid Waste Agency of Northern Cook County* v. *U.S. Army Corps of Engineers,* 531 U.S. 159 (2001) *(SWANCC).*

Today's ANPRM requests public input on issues associated with the definition of ''waters of the United States'' and also solicits information or data from the general public, the scientific community, and Federal and State resource agencies on the implications of the *SWANCC* decision for jurisdictional decisions under the CWA. The goal of the agencies is to develop proposed regulations that will further the public interest by clarifying what waters are subject to CWA jurisdiction and affording full protection to these waters through an appropriate focus of Federal and State resources consistent with the CWA. The input received from the public in response to today's ANPRM will be used by the agencies to determine the issues to be addressed and the substantive approach for a future proposed rulemaking addressing the scope of CWA jurisdiction.

Pending this rulemaking, should questions arise, the regulated community should seek assistance from the Corps and EPA, in accordance with the joint memorandum attached as Appendix A.

DATES: In order to be considered, comments or information in response to this ANPRM must be postmarked or e-mailed on or before March 3, 2003.

ADDRESSES: Comments may be submitted electronically, by mail, or through hand delivery/courier. Mail comments to: Water Docket, Environmental Protection Agency, Mailcode 4101T, 1200 Pennsylvania Ave., NW., Washington, DC 20460, Attention Docket ID No. OW–2002–0050.

FOR FURTHER INFORMATION CONTACT: For information on this ANPRM, contact either Donna Downing, U.S. Environmental Protection Agency, Office of Wetlands, Oceans and Watersheds (4502T), 1200 Pennsylvania Avenue N.W., Washington, DC 20460, phone: (202) 566–1366, e-mail: *CWAwaters@epa.gov,* or Ted Rugiel, U.S. Army Corps of Engineers, ATTN CECW–OR, 441 G Street NW., Washington, DC 20314–1000, phone: (202) 761–4595, e-mail: *Thaddeus.J.Rugiel@HQ02.USACE.ARMY.MIL.*

SUPPLEMENTARY INFORMATION:

I. General Information

A. Potentially Regulated Entities

Persons or entities that discharge pollutants (including dredged or fill material) to ''waters of the U.S.'' could be regulated by a rulemaking based on this ANPRM. The CWA generally prohibits the discharge of pollutants into ''waters of the U.S.'' without a permit issued by EPA or a State or Tribe approved by EPA under section 402 of the Act, or, in the case of dredged or fill material, by the Corps or an approved

State or Tribe under section 404 of the Act. In addition, under the CWA, States or approved Tribes establish water quality standards for ''waters of the U.S.'', and also may assume responsibility for issuance of CWA permits for discharges into waters and wetlands subject to the Act. Today's ANPRM seeks public input on what, if any, revisions in light of SWANCC might be appropriate to the regulations that define ''waters of the U.S.'', and today's ANPRM thus would be of interest to all entities discharging to, or regulating, such waters. In addition, because the Oil Pollution Act (OPA) is applicable to waters and wetlands subject to the CWA, today's ANPRM may have implications for persons or entities subject to the OPA. Examples of entities potentially regulated include:

Category	Examples of potentially regulated entities
State/Tribal governments or instrumentalities.	State/Tribal agencies or instrumentalities that discharge or spill pollutants into waters of the U.S.
Local governments or instrumentalities.	Local governments or instrumentalities that discharge or spill pollutants into waters of the U.S.
Federal government agencies or instrumentalities.	Federal government agencies or instrumentalities that discharge or spill pollutants into waters of the U.S.
Industrial, commercial, or agricultural entities.	Industrial, commercial, or agricultural entities that discharge or spill pollutants into waters of the U.S.
Land developers and landowners.	Land developers and landowners that discharge or spill pollutants into waters of the U.S.

This table is not intended to be exhaustive, but rather provides a guide for readers regarding entities that are likely to be regulated by a rulemaking based on this ANPRM. This table lists the types of entities that we are now aware of that could potentially be regulated. Other types of entities not listed in the table could also be regulated. To determine whether your organization or its activities could be regulated, you should carefully examine the discussion in this ANPRM. If you have questions regarding the applicability of this action to a particular entity, consult one of the persons listed in the preceding **FOR FURTHER INFORMATION CONTACT** section.

B. How Can I Get Copies of This Document and Other Related Information?

1. *Docket.* The agencies have established an official public docket for this action under Docket ID No. OW–2002–0050. The official public docket consists of the documents specifically referenced in this ANPRM, any public comments received, and other information related to this ANPRM. Although a part of the official docket, the public docket does not include Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. The official public docket is the collection of materials that is available for public viewing at the Water Docket in the EPA Docket Center, (EPA/DC) EPA West, Room B102, 1301 Constitution Ave., NW., Washington, DC. The EPA Docket Center Public Reading Room is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the Water Docket is (202) 566–2426. You may have to pay a reasonable fee for copying.

2. *Electronic Access.* You may access this Federal Register document electronically through the EPA Internet under the Federal Register listings at *http://www.epa.gov/fedrgstr/.*

An electronic version of the public docket is available through EPA's electronic public docket and comment system, EPA Dockets. You may use EPA Dockets at *http://www.epa.gov/edocket* to submit or view public comments, access the index listing of the contents of the official public docket, and to access those documents in the public docket that are available electronically. Once in the system, select search, then key in the appropriate docket identification number.

Certain types of information will not be placed in the EPA Dockets. Information claimed as CBI and other information whose disclosure is restricted by statute, which is not included in the official public docket, will not be available for public viewing in EPA's electronic public docket. EPA's policy is that copyrighted material will not be placed in EPA's electronic public docket but will be available only in printed, paper form in the official public docket. Although not all docket materials may be available electronically, you may still access any of the publicly available docket materials through the docket facility identified in I.B.1.

For those who submit public comments, it is important to note that EPA's policy is that public comments, whether submitted electronically or in paper, will be made available for public viewing in EPA's electronic public docket as EPA receives them and without change, unless the comment contains copyrighted material, CBI, or other information whose disclosure is restricted by statute. When EPA identifies a comment containing copyrighted material, EPA will provide a reference to that material in the version of the comment that is placed in EPA's electronic public docket. The entire printed comment, including the copyrighted material, will be available in the public docket.

Public comments submitted on computer disks that are mailed or delivered to the docket will be transferred to EPA's electronic public docket. Public comments that are mailed or delivered to the Docket will be scanned and placed in EPA's electronic public docket. Where practical, physical objects will be photographed, and the photograph will be placed in EPA's electronic public docket along with a brief description written by the docket staff.

C. How and To Whom Do I Submit Comments?

You may submit comments electronically, by mail, or through hand delivery/courier. To ensure proper receipt by EPA, identify the appropriate docket identification number (OW–2002–0050) in the subject line on the first page of your comment. Please ensure that your comments are submitted within the specified comment period. Comments received after the close of the comment period will be marked late. The agencies are not required to consider these late comments.

1. *Electronically.* If you submit an electronic comment as prescribed below, EPA recommends that you include your name, mailing address, and an e-mail address or other contact information in the body of your comment. Also include this contact information on the outside of any disk or CD ROM you submit, and in any cover letter accompanying the disk or CD ROM. This ensures that you can be identified as the submitter of the comment and allows EPA to contact you in case EPA cannot read your comment due to technical difficulties or needs further information on the substance of your comment. EPA's policy is that EPA will not edit your comment, and any identifying or contact information provided in the body of a comment will be included as part of the comment that is placed in the official public docket,

and made available in EPA's electronic public docket. If EPA cannot read your comment due to technical difficulties and cannot contact you for clarification, the agencies may not be able to consider your comment.

i. *EPA Dockets.* Your use of EPA's electronic public docket to submit comments to EPA electronically is EPA's preferred method for receiving comments. Go directly to EPA Dockets at *http://www.epa.gov/edocket*, and follow the online instructions for submitting comments. Once in the system, select search, and then key in Docket ID No. OW–2002–0050. The system is an anonymous access system, which means EPA will not know your identity, e-mail address, or other contact information unless you provide it in the body of your comment.

ii. *E-mail.* Comments may be sent by electronic mail (e-mail) to *CWAwaters@epa.gov*, Attention Docket ID No. OW–2002–0050. In contrast to EPA's electronic public docket, EPA's e-mail system is not an anonymous access system. If you send an e-mail comment directly to the Docket without going through EPA's electronic public docket, EPA's e-mail system automatically captures your e-mail address. E-mail addresses that are automatically captured by EPA's e-mail system are included as part of the comment that is placed in the official public docket, and made available in EPA's electronic public docket.

iii. *Disk or CD ROM.* You may submit comments on a disk or CD ROM that you mail to the mailing address identified in I.C.2. These electronic submissions will be accepted in WordPerfect or ASCII file format. Avoid the use of special characters and any form of encryption.

2. *By Mail.* Send four copies of your comments to: Water Docket, Environmental Protection Agency, Mailcode 4101T, 1200 Pennsylvania Ave., NW, Washington, DC 20460, Attention Docket ID No. OW–2002–0050.

3. *By Hand Delivery or Courier.* Deliver your comments to: Water Docket, EPA Docket Center, EPA West, Room B102, 1301 Constitution Avenue, NW, Washington, DC, Attention Docket ID No. OW–2002–0050. Such deliveries are only accepted during the Docket's normal hours of operation as identified in I.B.1.

D. What Should I Consider as I Prepare My Comments?

You may find the following suggestions helpful for preparing your comments:

a. Explain your views as clearly as possible.

b. Describe any assumptions that you used.

c. Provide any technical information and/or data on which you based your views.

d. If you estimate potential burden or costs, explain how you arrived at your estimate.

e. Provide specific examples to illustrate your concerns.

f. Offer alternatives.

g. Make sure to submit your comments by the comment period deadline identified.

h. To ensure proper receipt by EPA, identify the appropriate docket identification number in the subject line on the first page of your response. It would also be helpful if you provided the name, date, and **Federal Register** citation related to your comments.

II. The Importance of Updating the Regulations

The agencies have not engaged in a review of the regulations with the public concerning CWA jurisdiction for some time. This ANPRM will help ensure that the regulations are consistent with the CWA and the public understands what waters are subject to CWA jurisdiction. The goal of the agencies is to develop proposed regulations that will further the public interest by clarifying what waters are subject to CWA jurisdiction and affording full protection to these waters through an appropriate focus of Federal and State resources consistent with the CWA. It is appropriate to review the regulations to ensure that they are consistent with the *SWANCC* decision. *SWANCC* eliminates CWA jurisdiction over isolated waters that are intrastate and non-navigable, where the sole basis for asserting CWA jurisdiction is the actual or potential use of the waters as habitat for migratory birds that cross State lines in their migrations. *SWANCC* also calls into question whether CWA jurisdiction over isolated, intrastate, non-navigable waters could now be predicated on the other factors listed in the ''Migratory Bird Rule'' or the other rationales of 33 CFR 328.3(a)(3)(i)–(iii).

Although the *SWANCC* case itself specifically involves section 404 of the CWA, the Court's decision may also affect the scope of regulatory jurisdiction under other provisions of the CWA, including programs under sections 303, 311, 401, and 402. Under each of these sections, the relevant agencies have jurisdiction over ''waters of the United States.'' The agencies will consider the potential implications of the rulemaking for these other sections.

- *Section 404 dredged and fill material permit program.* This program establishes a permitting system to regulate discharges of dredged or fill material into waters of the United States.
- *Section 303 water quality standards program.* Under this program, States and authorized Indian Tribes establish water quality standards for navigable waters to ''protect the public health or welfare'' and ''enhance the quality of water'', ''taking into consideration their use and value for public water supplies, propagation of fish and wildlife, recreational purposes, and agriculture, industrial, and other purposes, and also taking into consideration their use and value for navigation.''
- *Section 311 spill program and the Oil Pollution Act (OPA).* Section 311 of the CWA addresses pollution from both oil and hazardous substance releases. Together with the Oil Pollution Act, it provides EPA and the U.S. Coast Guard with the authority to establish a program for preventing, preparing for, and responding to spills that occur in navigable waters of the United States.
- *Section 401 State water-quality certification program.* Section 401 provides that no Federal permit or license for activities that might result in a discharge to navigable waters may be issued unless a section 401 water-quality certification is obtained from or waived by States or authorized Tribes.
- *Section 402 National Pollutant Discharge Elimination System (NPDES) permitting program.* This program establishes a permitting system to regulate point source discharges of pollutants (other than dredged or fill material) into waters of the United States.

III. Legislative and Regulatory Context

The Federal Water Pollution Control Act Amendments, now known as the Clean Water Act (CWA), was enacted in 1972. In the years since its enactment, the scope of waters regulated under the CWA has been discussed in regulations, legislation, and judicial decisions.

The CWA was intended to ''restore and maintain the chemical, physical, and biological integrity of the Nation's waters.'' 33 U.S.C. 1251(a). Its specific provisions were designed to improve upon the protection of the Nation's waters provided under earlier statutory schemes such as the Rivers and Harbors Act of 1899 (''RHA'') (33 U.S.C. 403, 407, 411) and the Federal Water Pollution Control Act of 1948 (62 Stat. 1155) and its subsequent amendments through 1970. In doing so, Congress recognized ''the primary responsibilities and rights of States to prevent, reduce,

and eliminate pollution, to plan the development and use (including restoration, preservation, and enhancement) of land and water resources * * *'' 33 U.S.C. 1251(b).

The jurisdictional scope of the CWA is ''navigable waters,'' defined in the statute as ''waters of the United States, including the territorial seas.'' CWA section 502(7), 33 U.S.C. 1362(7). The existing CWA section 404 regulations define ''waters of the United States'' as follows:

(1) All waters which are currently used, or were used in the past, or may be susceptible to use in interstate or foreign commerce, including all waters which are subject to ebb and flow of the tide;

(2) All interstate waters including interstate wetlands;

(3) All other waters such as intrastate lakes, rivers, streams (including intermittent streams), mudflats, sandflats, wetlands, sloughs, prairie potholes, wet meadows, playa lakes, or natural ponds, the use, degradation or destruction of which could affect interstate or foreign commerce including any such waters:

(i) which are or could be used by interstate or foreign travelers for recreational or other purposes; or

(ii) from which fish or shellfish are or could be taken and sold in interstate or foreign commerce; or

(iii) which are used or could be used for industrial purposes by industries in interstate commerce.

(4) All impoundments of waters otherwise defined as waters of the United States under the definition;

(5) Tributaries of waters identified in paragraphs (a)(1)–(4) of this section;

(6) The territorial seas;

(7) Wetlands adjacent to waters (other than waters that are themselves wetlands) identified in paragraphs (a)(1)–(6) of this section.

(8) Waters of the United States do not include prior converted cropland ... Waste treatment systems, including treatment ponds or lagoons designed to meet the requirements of CWA (other than cooling ponds ...) are not waters of the United States. 40 CFR.230.3(s); 33 CFR 328.3(a).

Counterpart and substantively similar regulatory definitions appear at 40 CFR 110.1, 112.2, 116.3, 117.1, 122.2, 232.2, 300.5, part 300 App. E, 302.3 and 401.11 (hereafter referred to as ''the counterpart definitions'').

In regulatory preambles, both the Corps and EPA provided examples of additional types of links to interstate commerce which might serve as a basis under 40 CFR 230.3(a)(3) and 33 CFR 328.3(a)(3) for establishing CWA jurisdiction over intrastate waters which were not part of the tributary system or their adjacent wetlands. These included use of waters (1) as habitat by birds protected by Migratory Bird Treaties or which cross State lines, (2) as habitat for endangered species, or (3) to irrigate crops sold in commerce. 51 FR 41217 (November 13, 1986), 53 FR 20765 (June 6, 1988). These examples became known as the ''Migratory Bird Rule,'' even though the examples were neither a rule nor entirely about birds. The Migratory Bird Rule later became the focus of the *SWANCC* case.

IV. Potential Natural Resource Implications

To date, some quantitative studies and anecdotal data provide early estimates of potential resource implications of the *SWANCC* decision. One of the purposes of the ANPRM is to solicit additional information, data, or studies addressing the extent of resource impacts to isolated, intrastate, non-navigable waters.

Non-navigable intrastate isolated waters occur throughout the country. Their extent depends on a variety of factors including topography, climate, and hydrologic forces. Preliminary assessments of potential resource impacts vary widely depending on the scenarios considered. See, *e.g.*, Ducks Unlimited, ''The SWANCC Decision: Implications for Wetlands and Waterfowl'' (September 2001) (available at *http://www.ducks.org/conservation/404_report.asp*); ASWM, ''SWANCC Decision and the State Regulation of Wetlands,'' (June 2001) (available at *http://www.aswm.org*).

There is an extensive body of knowledge about the functions and values of wetlands, which include flood risk reduction, water quality improvement, fish and wildlife habitat, and maintenance of the hydrologic integrity of aquatic ecosystems. The ANPRM seeks information regarding the functions and values of wetlands and other waters that may be affected by the issues discussed in this ANPRM.

V. Solicitation of Comments

The agencies are seeking comment on issues related to the jurisdictional status of isolated waters under the CWA which the public wishes to call to our attention. To assist the public in considering these issues, the following discussion and specific questions are presented. The agencies will carefully consider the responses received to this ANPRM in determining what regulatory changes may be appropriate and the issues to be addressed in a proposed rulemaking to clarify CWA jurisdiction.

The *SWANCC* holding eliminates CWA jurisdiction over isolated, intrastate, non-navigable waters where the sole basis for asserting CWA jurisdiction is the actual or potential use of the waters as habitat for migratory birds that cross State lines in their migrations. 531 U.S. at 174 (''We hold that 33 CFR 328.3(a)(3) (1999), as clarified and applied to petitioner's balefill site pursuant to the ''Migratory Bird Rule,'' 51 FR 41217 (1986), exceeds the authority granted to respondents under section 404(a) of the CWA.''). The agencies seek comment on the use of the factors in 33 CFR 328.3(a)(3)(i)–(iii) or the counterpart regulations in determining CWA jurisdiction over isolated, intrastate, non-navigable waters.

The agencies solicit comment from the public on the following issues:

(1) Whether, and, if so, under what circumstances, the factors listed in 33 CFR 328.3(a)(3)(i)–(iii) (*i.e.*, use of the water by interstate or foreign travelers for recreational or other purposes, the presence of fish or shellfish that could be taken and sold in interstate commerce, the use of the water for industrial purposes by industries in interstate commerce) or any other factors provide a basis for determining CWA jurisdiction over isolated, intrastate, non-navigable waters?

(2) Whether the regulations should define ''isolated waters,'' and if so, what factors should be considered in determining whether a water is or is not isolated for jurisdictional purposes?

Solicitation of Information

In answering the questions set forth above, please provide, as appropriate, any information (*e.g.*, scientific and technical studies and data, analysis of environmental impacts, effects on interstate commerce, other impacts, etc.) supporting your views, and specific recommendations on how to implement such views. Additionally, we invite your views as to whether any other revisions are needed to the existing regulations on which waters are jurisdictional under the CWA. As noted elsewhere in this document, the agencies are also soliciting data and information on the availability and effectiveness of other Federal or State programs for the protection of aquatic resources, and on the functions and values of wetlands and other waters that may be affected by the issues discussed in this ANPRM.

VI. Related Federal and State Authorities

The *SWANCC* decision addresses CWA jurisdiction, and other Federal or

State laws and programs may still protect a water and related ecosystem even if that water is no longer jurisdictional under the CWA following *SWANCC*. The Federal government remains committed to wetlands protection through the Food Security Act's Swampbuster requirements and Federal agricultural program benefits and restoration through such Federal programs as the Wetlands Reserve Program (administered by the U.S. Department of Agriculture), grant making programs such as Partners in Wildlife (administered by the Fish and Wildlife Service), the Coastal Wetlands Restoration Program (administered by the National Marine Fisheries Service), the State Grant, Five Star Restoration, and National Estuary Programs (administered by EPA), and the Migratory Bird Conservation Commission (composed of the Secretaries of Interior and Agriculture, the Administrator of EPA and Members of Congress).

The *SWANCC* decision also highlights the role of States in protecting waters not addressed by Federal law. Prior to *SWANCC*, fifteen States had programs that addressed isolated wetlands. Since *SWANCC*, additional States have considered, and two have adopted, legislation to protect isolated waters. The Federal agencies have a number of initiatives to assist States in these efforts to protect wetlands. For example, EPA's Wetland Program Development Grants are available to assist States, Tribes, and local governments for building their wetland program capacities. In addition, the U.S. Department of Justice and other Federal agencies co-sponsored a national wetlands conference with the National Governors Association Center for Best Practices, National Conference of State Legislatures, the Association of State Wetlands Managers, and the National Association of Attorneys General. This conference and the dialogue that has ensued will promote close collaboration between Federal agencies and States in developing, implementing, and enforcing wetlands protection programs. EPA also is providing funding to the National Governors Association Center for Best Practices to assist States in developing appropriate policies and actions to protect intrastate isolated waters.

In light of this, the agencies solicit information and data from the general public, the scientific community, and Federal and State resource agencies on the availability and effectiveness of other Federal or State programs for the protection of aquatic resources and practical experience with their implementation. The agencies are also interested in data and comments from State and local agencies on the effect of no longer asserting jurisdiction over some of the waters (and discharges to those waters) in a watershed on the implementation of Total Maximum Daily Loads (TMDLs) and attainment of water quality standards.

VII. Statutory and Executive Order Reviews

A. Executive Order 12866

Under Executive Order 12866 (58 FR 51735, October 4, 1993), EPA and the Corps must determine whether the regulatory action is ''significant'' and therefore subject to review by the Office of Management and Budget (OMB) and the requirements of the Executive Order. The Order defines ''significant regulatory action'' as one that is likely to result in a rule that may:

(1) Have an annual effect on the economy of $100 million or more or adversely affect in a material way the economy, a sector of the economy, productivity, competition, jobs, the environment, public health or safety, or State, local, or Tribal governments or communities;

(2) Create a serious inconsistency or otherwise interfere with an action taken or planned by another agency;

(3) Materially alter the budgetary impact of entitlements, grants, user fees, or loan programs or the rights and obligations of recipients thereof; or

(4) Raise novel legal or policy issues arising out of legal mandates, the President's priorities, or the principles set forth in the Executive Order.

Pursuant to the terms of Executive Order 12866, it has been determined that this Advanced Notice of Proposed Rulemaking is a ''significant regulatory action'' in light of the provisions of paragraph (4) above as it raises novel legal or policy issues. As such, this action was submitted to OMB for review. Changes made in response to OMB suggestions or recommendations will be documented in the public record.

B. National Environmental Policy Act

As required by the National Environmental Policy Act (NEPA), the Corps prepares appropriate environmental documentation for its activities affecting the quality of the human environment. The Corps has determined that today's Advance Notice of Proposed Rulemaking merely solicits early comment on issues associated with the scope of waters that are properly subject to the CWA, and information or data from the general public, the scientific community, and Federal and State resource agencies on the implications of the *SWANCC* decision for the protection of aquatic resources. In light of this, the Corps has determined that today's ANPRM does not constitute a major Federal action significantly affecting the quality of the human environment, and thus does not require the preparation of an Environmental Impact Statement (EIS).

Dated: January 10, 2003.

Christine Todd Whitman,

Administrator, Environmental Protection Agency.

Dated: January 10, 2003.

R.L. Brownlee,

Acting Assistant Secretary of the Army, (Civil Works), Department of the Army.

Note: The following guidance document will not appear in the Code of Federal Regulations.

Appendix A

Joint Memorandum

Introduction

This document provides clarifying guidance regarding the Supreme Court's decision in *Solid Waste Agency of Northern Cook County* v. *United States Army Corps of Engineers,* 531 U.S. 159 (2001) (''SWANCC'') and addresses several legal issues concerning Clean Water Act (''CWA'') jurisdiction that have arisen since *SWANCC* in various factual scenarios involving federal regulation of ''navigable waters.'' Because the case law interpreting *SWANCC* has developed over the last two years, the Agencies are issuing this updated guidance, which supersedes prior guidance on this issue. The Corps and EPA are also initiating a rulemaking process to collect information and to consider jurisdictional issues as set forth in the attached ANPRM. Jurisdictional decisions will be based on Supreme Court cases including *United States* v. *Riverside Bayview Homes,* 474 U.S. 121 (1985) and *SWANCC,* regulations, and applicable case law in each jurisdiction.

Background

In *SWANCC,* the Supreme Court held that the Army Corps of Engineers had exceeded its authority in asserting CWA jurisdiction pursuant to section 404(a) over isolated, intrastate, non-navigable waters under 33 C.F.R. 328.3(a)(3), based on their use as habitat for migratory birds pursuant to preamble language commonly referred to as the ''Migratory Bird Rule,'' 51 FR 41217 (1986). ''Navigable waters'' are defined in section 502 of the CWA to mean ''waters of the United States, including the territorial seas.'' In *SWANCC,* the Court determined that the term ''navigable'' had significance in indicating the authority Congress intended to exercise in asserting CWA jurisdiction. 531 U.S. at 172. After reviewing the jurisdictional scope of the statutory definition of ''navigable waters'' in section 502, the Court concluded that neither the text of the statute nor its legislative history supported the

Corps' assertion of jurisdiction over the waters involved in *SWANCC. Id.* at 170–171.

In *SWANCC,* the Supreme Court recognized that ''Congress passed the CWA for the stated purpose of 'restoring and maintaining the chemical, physical, and biological integrity of the Nation's waters' '' and also noted that ''Congress chose to 'recognize, preserve, and protect the primary responsibilities and rights of States to prevent, reduce, and eliminate pollution, to plan the development and use (including restoration, preservation, and enhancement) of land and water resources.' '' *Id.* at 166–67 (citing 33 U.S.C. 1251(a) and (b)). However, expressing ''serious constitutional and federalism questions'' raised by the Corps' interpretation of the CWA, the Court stated that ''where an administrative interpretation of a statute invokes the outer limits of Congress' power, we expect a clear indication that Congress intended that result.'' *Id.* at 174, 172. Finding ''nothing approaching a clear statement from Congress that it intended section 404(a) to reach an abandoned sand and gravel pit'' (*id.* at 174), the Court held that the Migratory Bird Rule, as applied to petitioners' property, exceeded the agencies' authority under section 404(a). *Id.* at 174.

The Scope of CWA Jurisdiction After SWANCC

Because *SWANCC* limited use of 33 CFR § 328.3(a)(3) as a basis of jurisdiction over certain isolated waters, it has focused greater attention on CWA jurisdiction generally, and specifically over tributaries to jurisdictional waters and over wetlands that are ''adjacent wetlands'' for CWA purposes.

As indicated, section 502 of the CWA defines the term navigable waters to mean ''waters of the United States, including the territorial seas.'' The Supreme Court has recognized that this definition clearly includes those waters that are considered traditional navigable waters. In *SWANCC,* the Court noted that while ''the word 'navigable' in the statute was of 'limited import' '' (quoting *Riverside,* 474 U.S. 121 (1985)), ''the term 'navigable' has at least the import of showing us what Congress had in mind as its authority for enacting the CWA: traditional jurisdiction over waters that were or had been navigable in fact or which could reasonably be so made.'' 531 U.S. at 172. In addition, the Court reiterated in *SWANCC* that Congress evidenced its intent to regulate ''at least some waters that would not be deemed 'navigable' under the classical understanding of that term.'' *SWANCC* at 171 (quoting *Riverside,* 474 U.S. at 133). Relying on that intent, for many years, EPA and the Corps have interpreted their regulations to assert CWA jurisdiction over non-navigable tributaries of navigable waters and their adjacent wetlands. Courts have upheld the view that traditional navigable waters and, generally speaking, their tributary systems (and their adjacent wetlands) remain subject to CWA jurisdiction.

Several federal district and appellate courts have addressed the effect of *SWANCC* on CWA jurisdiction, and the case law on the precise scope of federal CWA jurisdiction in light of *SWANCC* is still developing. While a majority of cases hold that *SWANCC* applies only to waters that are isolated, intrastate and non-navigable, several courts have interpreted *SWANCC*'s reasoning to apply to waters other than the isolated waters at issue in that case. This memorandum attempts to add greater clarity concerning federal CWA jurisdiction following *SWANCC* by identifying specific categories of waters, explaining which categories of waters are jurisdictional or non-jurisdictional, and pointing out where more refined factual and legal analysis will be required to make a jurisdictional determination.

Although the *SWANCC* case itself specifically involved Section 404 of the CWA, the Court's decision may affect the scope of regulatory jurisdiction under other provisions of the CWA as well, including the Section 402 NPDES program, the Section 311 oil spill program, water quality standards under Section 303, and Section 401 water quality certification. Under each of these sections, the relevant agencies have jurisdiction over ''waters of the United States.'' CWA section 502(7).

This memorandum does not discuss the exact factual predicates that are necessary to establish jurisdiction in individual cases. We recognize that the field staff and the public could benefit from additional guidance on how to apply the applicable legal principles to individual cases.[1] Should questions arise concerning CWA jurisdiction, the regulated community should seek assistance from the Corps and EPA.

A. Isolated, Intrastate Waters That are Non-Navigable

SWANCC squarely eliminates CWA jurisdiction over isolated waters that are intrastate and non-navigable, where the sole basis for asserting CWA jurisdiction is the actual or potential use of the waters as habitat for migratory birds that cross state lines in their migrations. 531 U.S. at 174 (''We hold that 33 CFR § 328.3(a)(3) (1999), as clarified and applied to petitioner's balefill site pursuant to the 'Migratory Bird Rule,' 51 FR 41217 (1986), exceeds the authority granted to respondents under § 404(a) of the CWA.''). The EPA and the Corps are now precluded from asserting CWA jurisdiction in such situations, including over waters such as isolated, non-navigable, intrastate vernal pools, playa lakes and pocosins. *SWANCC* also calls into question whether CWA jurisdiction over isolated, intrastate, non-navigable waters could now be predicated on the other factors listed in the Migratory Bird Rule, 51 FR 41217 (*i.e.*, use of the water as habitat for birds protected by Migratory Bird Treaties; use of the water as habitat for Federally protected endangered or threatened species; or use of the water to irrigate crops sold in interstate commerce).

By the same token, in light of *SWANCC,* it is uncertain whether there remains any basis for jurisdiction under the other rationales of § 328.3(a)(3)(i)–(iii) over isolated, non-navigable, intrastate waters (*i.e.*, use of the water by interstate or foreign travelers for recreational or other purposes; the presence of fish or shellfish that could be taken and sold in interstate commerce; use of the water for industrial purposes by industries in interstate commerce). Furthermore, within the states comprising the Fourth Circuit, CWA jurisdiction under 33 CFR § 328.3(a)(3) in its entirety has been precluded since 1997 by the Fourth Circuit's ruling in *United States* v. *Wilson,* 133 F. 3d 251, 257 (4th Cir. 1997) (invalidating 33 CFR § 328.3(a)(3)).

In view of *SWANCC,* neither agency will assert CWA jurisdiction over isolated waters that are both intrastate and non-navigable, where the sole basis available for asserting CWA jurisdiction rests on any of the factors listed in the ''Migratory Bird Rule.'' In addition, in view of the uncertainties after *SWANCC* concerning jurisdiction over isolated waters that are both intrastate and non-navigable based on other grounds listed in 33 CFR § 328.3(a)(3)(i)–(iii), field staff should seek formal project-specific Headquarters approval prior to asserting jurisdiction over such waters, including permitting and enforcement actions.

B. Traditional Navigable Waters

As noted, traditional navigable waters are jurisdictional. Traditional navigable waters are waters that are subject to the ebb and flow of the tide, or waters that are presently used, or have been used in the past, or may be susceptible for use to transport interstate or foreign commerce. 33 CFR § 328.3(a)(1); *United States* v. *Appalachian Elec. Power Co.,* 311 U.S. 377, 407–408 (1940) (water considered navigable, although not navigable at present but could be made navigable with reasonable improvements); *Economy Light & Power Co.* v. *United States,* 256 U.S. 113 (1911) (dams and other structures do not eliminate navigability); *SWANCC,* 531 U.S. at 172 (referring to traditional jurisdiction over waters that were or had been navigable in fact or which could reasonably be so made).[2]

In accord with the analysis in *SWANCC,* waters that fall within the definition of traditional navigable waters remain jurisdictional under the CWA. Thus, isolated, intrastate waters that are capable of supporting navigation by watercraft remain subject to CWA jurisdiction after SWANCC if they are traditional navigable waters, *i.e.*, if they meet any of the tests for being navigable-in-fact. *See, e.g., Colvin* v. *United States* 181 F. Supp. 2d 1050 (C.D. Cal. 2001) (isolated

[1] The CWA provisions and regulations described in this document contain legally binding requirements. This document does not substitute for those provisions or regulations, nor is it a regulation itself. It does not impose legally binding requirements on EPA, the Corps, or the regulated community, and may not apply to a particular situation depending on the circumstances. Any decisions regarding a particular water will be based on the applicable statutes, regulations, and case law. Therefore, interested person are free to raise questions and objections about the appropriateness of the application of this guidance to a particular situation, and EPA and/or the Corps will consider whether or not the recommendations or interpretations of this guidance are appropriate in that situation based on the law and regulations.

[2] These traditional navigable waters are not limited to those regulated under Section 10 of the Rivers and Harbors Act of 1899; traditional navigable waters include waters which, although used, susceptibale to use, or historically used, to transport goods or people in commerce, do not form part of a continuous wateborne highway.

man-made water body capable of boating found to be ''water of the United States'').

C. Adjacent Wetlands

(1) Wetlands Adjacent to Traditional Navigable Waters

CWA jurisdiction also extends to wetlands that are adjacent to traditional navigable waters. The Supreme Court did not disturb its earlier holding in *Riverside* when it rendered its decision in *SWANCC. Riverside* dealt with a wetland adjacent to Black Creek, a traditional navigable water. 474 U.S. 121 (1985); *see also SWANCC,* 531 U.S. at 167 (''[i]n *Riverside,* we held that the Corps had section 404(a) jurisdiction over wetlands that actually abutted on a navigable waterway''). The Court in *Riverside* found that ''Congress'; concern for the protection of water quality and aquatic ecosystems indicated its intent to regulate wetlands 'inseparably bound up with' '' jurisdictional waters. 474 U.S. at 134. Thus, wetlands adjacent to traditional navigable waters clearly remain jurisdictional after *SWANCC.* The Corps and EPA currently define 'adjacent' as ''bordering, contiguous, or neighboring. Wetlands separated from other waters of the United States by man-made dikes or barriers, natural river berms, beach dunes, and the like are 'adjacent wetlands.' '' 33 CFR § 328.3(b); 40 CFR § 230.3(b). The Supreme Court has not itself defined the term ''adjacent,'' nor stated whether the basis for adjacency is geographic proximity or hydrology.

(2) Wetlands Adjacent to Non-Navigable Waters

The reasoning in Riverside, as followed by a number of post-SWANCC courts, supports jurisdiction over wetlands adjacent to non-navigable waters that are tributaries to navigable waters. Since SWANCC, some courts have expressed the view that SWANCC raised questions about adjacency jurisdiction, so that wetlands are jurisdictional only if they are adjacent to navigable waters. *See, e.g., Rice* v. *Harken,* discussed *infra.*

D. Tributaries

A number of court decisions have held that *SWANCC* does not change the principle that CWA jurisdiction extends to tributaries of navigable waters. *See, e.g., Headwaters* v. *Talent Irrigation Dist.,* 243 F.3d 526, 534 (9th Cir. 2001) (''Even tributaries that flow intermittently are 'waters of the United States' ''); *United States* v. *Interstate Gen. Co,* No. 01–4513, slip op. at 7, 2002 WL 1421411 (4th Cir. July 2, 2002), *aff'ing* 152 F. Supp. 2d 843 (D. Md. 2001) (refusing to grant writ of coram nobis; rejecting argument that *SWANCC* eliminated jurisdiction over wetlands adjacent to non-navigable tributaries); *United States* v. *Krilich,* 393F.3d 784 (7th Cir. 2002) (rejecting motion to vacate consent decree, finding that *SWANCC* did not alter regulations interpreting ''waters of the U.S.'' other than 33 C.F.R. § 328.3(a)(3)); *Community Ass. for Restoration of the Env't* v. *Henry Bosma Dairy,* 305 F.3d 953 (9th Cir. 2002) (drain that flowed into a canal that flows into a river is jurisdictional); *Idaho Rural Council* v. *Bosma,* 143 F. Supp. 2d 1169, 1178 (D. Idaho 2001) (''waters of the United States include waters that are tributary to navigable waters''); *Aiello* v. *Town of Brookhaven,* 136 F. Supp. 2d 81, 118 (E.D. N.Y. 2001) (non-navigable pond and creek determined to be tributaries of navigable waters, and therefore ''waters of the United States under the CWA''). Jurisdiction has been recognized even when the tributaries in question flow for a significant distance before reaching a navigable water or are several times removed from the navigable waters (*i.e.*, ''tributaries of tributaries''). *See, e.g., United States* v. *Lamplight Equestrian Ctr.,* No. 00 C 6486, 2002 WL 360652, at *8 (ND. Ill. Mar. 8, 2002) (''Even where the distance from the tributary to the navigable water is significant, the quality of the tributary is still vital to the quality of navigable waters''); *United States* v. *Buday,* 138 F. Supp. 2d 1282, 1291–92 (D. Mont. 2001) (''water quality of tributaries * * * distant though the tributaries may be from navigable streams, is vital to the quality of navigable waters''); *United States* v. *Rueth Dev. Co.,* No. 2:96CV540, 2001 WL 17580078 (N.D. Ind. Sept. 26, 2001) (refusing to reopen a consent decree in a CWA case and determining that jurisdiction remained over wetlands adjacent to a non-navigable (man-made) waterway that flows into a navigable water).

Some courts have interpreted the reasoning in *SWANCC* to potentially circumscribe CWA jurisdiction over tributaries by finding CWA jurisdiction attaches only where navigable waters and waters immediately adjacent to navigable waters are involved. *Rice* v. *Harken* is the leading case taking the narrowest view of CWA jurisdiction after *SWANCC.* 250 F.3d 264 (5th Cir. 2001) (rehearing denied). *Harken* interpreted the scope of ''navigable waters'' under the Oil Pollution Act (OPA). The Fifth Circuit relied on *SWANCC* to conclude ''it appears that a body of water is subject to regulation under the CWA if the body of water is actually navigable or is adjacent to an open body of navigable water.'' 250 F.3d at 269. The analysis in *Harken* implies that the Fifth Circuit might limit CWA jurisdiction to only those tributaries that are traditionally navigable or immediately adjacent to a navigable water.

A few post-*SWANCC* district court opinions have relied on *Harken* or reasoning similar to that employed by the Harken court to limit jurisdiction. *See, e.g., United States* v. *Rapanos,* 190 F. Supp. 2d 1011(E.D. Mich. 2002) (government appeal pending) (''the Court finds as a matter of law that the wetlands on Defendant's property were not directly adjacent to navigable waters, and therefore, the government cannot regulate Defendant's property.''); *United States* v. *Needham,* No. 6:01–CV–01897, 2002 WL 1162790 (W.D. La. Jan. 23, 2002) (government appeal pending) (district court affirmed finding of no liability by bankruptcy court for debtors under OPA for discharge of oil since drainage ditch into which oil was discharged was found to be neither a navigable water nor adjacent to an open body of navigable water). *See alsoUnited States* v. *Newdunn,* 195 F. Supp. 2d 751 (E.D. Va. 2002) (government appeal pending) (wetlands and tributaries not contiguous or adjacent to navigable waters are outside CWA jurisdiction); *United States* v. *RGM Corp.,* 222 F. Supp. 2d 780 (E.D. Va. 2002) (government appeal pending) (wetlands on property not contiguous to navigable river and, thus, jurisdiction not established based upon adjacency to navigable water).

Another question that has arisen is whether CWA jurisdiction is affected when a surface tributary to jurisdictional waters flows for some of its length through ditches, culverts, pipes, storm sewers, or similar manmade conveyances. A number of courts have held that waters with manmade features are jurisdictional. For example, in *Headwaters Inc.* v. *Talent Irrigation District,* the Ninth Circuit held that manmade irrigation canals that diverted water from one set of natural streams and lakes to other streams and creeks were connected as tributaries to waters of the United States, and consequently fell within the purview of CWA jurisdiction. 243 F.3d at 533–34. However, some courts have taken a different view of the circumstances under which man-made conveyances satisfy the requirements for CWA jurisdiction. *See, e.g., Newdunn,* 195 F. Supp. 2d at 765 (government appeal pending) (court determined that Corps had failed to carry its burden of establishing CWA jurisdiction over wetlands from which surface water had to pass through a spur ditch, a series of man-made ditches and culverts as well as non-navigable portions of a creek before finally reaching navigable waters).

A number of courts have held that waters connected to traditional navigable waters only intermittently or ephemerally are subject to CWA jurisdiction. The language and reasoning in the Ninth Circuit's decision in *Headwaters Inc.* v. *Talent Irrigation District* indicates that the intermittent flow of waters does not affect CWA jurisdiction. 243 F.3d at 534 (''Even tributaries that flow intermittently are 'waters of the United States.' ''). Other cases, however, have suggested that *SWANCC* eliminated from CWA jurisdiction some waters that flow only intermittently. *See, e.g., Newdunn,* 195 F. Supp. 2d at 764, 767–68 (government appeal pending) (ditches and culverts with intermittent flow not jurisdictional).

A factor in determining jurisdiction over waters with intermittent flows is the presence or absence of an ordinary high water mark (OHWM). Corps regulations provide that, in the absence of adjacent wetlands, the lateral limits of non-tidal waters extend to the OHWM (33 CFR 328.4(c)(1)). One court has interpreted this regulation to require the presence of a continuous OHWM. *United States* v. *RGM,* 222 F. Supp. 2d 780 (E.D. Va. 2002) (government appeal pending).

Conclusion

In light of *SWANCC,* field staff should not assert CWA jurisdiction over isolated waters that are both intrastate and non-navigable, where the sole basis available for asserting CWA jurisdiction rests on any of the factors listed in the ''Migratory Bird Rule.'' In addition, field staff should seek formal project-specific HQ approval prior to asserting jurisdiction over waters based on

other factors listed in 33 CFR 328.3(a)(3)(i)–(iii).

Field staff should continue to assert jurisdiction over traditional navigable waters (and adjacent wetlands) and, generally speaking, their tributary systems (and adjacent wetlands). Field staff should make jurisdictional and permitting decisions on a case-by-case basis considering this guidance, applicable regulations, and any additional relevant court decisions. Where questions remain, the regulated community should seek assistance from the agencies on questions of jurisdiction.

Robert E. Fabricant,

General Counsel, Environmental Protection Agency.

Steven J. Morello,

General Counsel, Department of the Army.

[FR Doc. 03–960 Filed 1–14–03; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 52

[IN140–1b; FRL–7433–6]

Approval and Promulgation of Implementation Plans; Indiana

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.

SUMMARY: The EPA is proposing to conditionally approve rules submitted by the State of Indiana as revisions to its State Implementation Plan(SIP) for prevention of significant deterioration (PSD) provisions for attainment areas for the Indiana Department of Environmental Management.

In the ''Rules and Regulations'' section of this **Federal Register**, EPA is approving the State's request as a direct final rule without prior proposal because EPA views this action as noncontroversial and anticipates no adverse comments. The rationale for approval is set forth in the direct final rule. If EPA receives no written adverse comments, EPA will take no further action on this proposed rule. If EPA receives written adverse comment, we will publish a timely withdrawal of the direct final rule in the **Federal Register** and inform the public that the rule will not take effect. In that event, EPA will address all relevant public comments in a subsequent final rule based on this proposed rule. In either event, EPA will not institute a second comment period on this action. Any parties interested in commenting must do so at this time.

DATES: Comments on this action must be received by February 14, 2003.

ADDRESSES: Written comments should be sent to: Pamela Blakley, Chief, Permits and Grants Section (IL/IN/OH), Air Programs Branch (AR–18J), U.S. Environmental Protection Agency, Region 5, 77 West Jackson Boulevard, Chicago, Illinois 60604.

A copy of the State's request is available for inspection at the above address.

FOR FURTHER INFORMATION CONTACT: Julie Capasso, Environmental Scientist, Permits and Grants Section (IL/IN/OH), Air Programs Branch, (AR–18J), U.S. Environmental Protection Agency, Region 5, 77 West Jackson Boulevard, Chicago, Illinois 60604, telephone (312) 886–1426.

SUPPLEMENTARY INFORMATION: Throughout this document whenever ''we,'' ''us,'' or ''our'' are used we mean the EPA.

I. What action is EPA taking today?
II. Where can I find more information about this proposal and corresponding direct final rule?

I. What Action Is EPA Taking Today?

The EPA is proposing to conditionally approve rules submitted by the State of Indiana as revisions to its State Implementation Plan (SIP) for prevention of significant deterioration (PSD) provisions for attainment areas for the Indiana Department of Environmental Management.

II. Where Can I Find More Information About This Proposal and Corresponding Direct Final Rule?

For additional information see the direct final rule published in the rules and regulations section of this **Federal Register**.

Authority: 42 U.S.C. 4201 *et seq.*

Dated: December 18, 2002.

Bharat Mathur,

Acting Regional Administrator, Region 5.

[FR Doc. 03–617 Filed 1–14–03; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 52

[MD137–3090b; FRL–7420–9]

Approval and Promulgation of Air Quality Implementation Plans; Maryland; Revision to the Control of Volatile Organic Compound Emissions From Screen Printing and Digital Imaging

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.

SUMMARY: EPA proposes to approve the State Implementation Plan (SIP) revision submitted by the State of Maryland establishing reasonable available control technology (RACT) to limit volatile organic compound (VOC) emissions from an overprint varnish that is used in the cosmetic industry. This action also proposes to add new definitions and amend certain existing definitions for terms used in the regulations. In the Final Rules section of this **Federal Register**, EPA is approving the State's SIP submittal as a direct final rule without prior proposal because the Agency views this as a noncontroversial submittal and anticipates no adverse comments. A more detailed description of the state submittal and EPA's evaluation are included in a Technical Support Document (TSD) prepared in support of this rulemaking action. A copy of the TSD is available, upon request, from the EPA Regional Office listed in the **ADDRESSES** section of this document. If no adverse comments are received in response to this action, no further activity is contemplated. If EPA receives adverse comments, the direct final rule will be withdrawn and all public comments received will be addressed in a subsequent final rule based on this proposed rule. EPA will not institute a second comment period. Any parties interested in commenting on this action should do so at this time.

DATES: Comments must be received in writing by February 14, 2003.

ADDRESSES: Written comments should be addressed to Walter Wilkie, Acting Branch Chief, Air Quality Planning and Information Services Branch, Mailcode 3AP21, U.S. Environmental Protection Agency, Region III, 1650 Arch Street, Philadelphia, Pennsylvania 19103. Copies of the documents relevant to this action are available for public inspection during normal business hours at the Air Protection Division, U.S. Environmental Protection Agency, Region III, 1650 Arch Street, Philadelphia, Pennsylvania 19103; and the Maryland Department of the Environment, 1800 Washington Boulevard, Suite 705, Baltimore, Maryland 21230.

FOR FURTHER INFORMATION CONTACT: Ellen Wentworth, (215) 814–2034, at the EPA Region III address above, or by e-mail at *wentworth.ellen@epa.gov.* Please note that while questions may be posed via telephone and e-mail, formal comments must be submitted in writing, as indicated in the **ADDRESSES** section of this document.

Daniel Gilligan, President
Petroleum Marketers Association of America
1901 N. Fort Myer Drive- Suite 500
Arlington, VA 22209-1604

Dear Mr. Gilligan:

This letter is in response to your request for the Agency's view regarding whether several approaches under consideration by your members would satisfy 40 CFR §112.7(a)(2)'s "equivalent environmental protection" provision and for clarification of the scope of the requirements in 40 CFR §112.7(h)(entitled "Facility tank car and tank truck loading/unloading rack (excluding offshore facilities)"). We discuss each of your proposals and questions below. Please note that the guidance provided in this letter is based on generalized assumptions and may not be applicable in a particular case based on site-specific circumstances.

"Equivalent Environmental Protection"

Integrity Testing

The newly amended SPCC provisions regarding bulk storage container integrity require, among other things, that each aboveground container be tested for integrity "on a regular schedule." 40 CFR §112.8(c)(6). These regulations further provide that "you must combine visual inspection with another testing technique such as hydrostatic testing, radiographic testing, ultrasonic testing, acoustic emissions testing, or another system of non-destructive shell testing." As you know, however, the regulations also allow deviations from this requirement where "you provide equivalent environmental protection by some other means of spill prevention, control, or countermeasure." 40 CFR §112.7(a)(2). You have asked whether, for shop-built containers, visual inspection plus certain actions to ensure that the containers are not in contact with the soil would likely be considered to provide "equivalent environmental protection" to visual inspection plus another form of testing.

It is our view that for well-designed shop-built containers with a shell capacity of 30,000 gallons or under, combining appropriate visual inspection with the measures described below would generally provide environmental protection equivalent to that provided by visual inspection plus another form of testing. Specifically, the Agency generally believes that visual inspection plus elevation of a shop-built container in a manner that decreases corrosion potential

(as compared to a container in contact with soil)[1] and makes all sides of the container, including the bottom, visible during inspection (e.g., where the containers are mounted on structural supports, saddles, or some forms of grillage) would be considered "equivalent." In a similar vein, we'd also generally believe an approach that combines visual inspection with placement of a barrier between the container and the ground, designed and operated in a way that ensures that any leaks are immediately detected, to be considered "equivalent." For example, we believe it would generally provide equivalent environmental protection to place a shop-built container on an adequately designed, maintained, and inspected synthetic liner.[2] We believe these approaches would generally provide equivalent environmental protection when used for shop-built containers (which generally have a lower failure potential than field-erected containers), because these approaches generally reduce corrosion potential and ensure detection of any container failure before it becomes significant.

In determining the appropriate SPCC plan requirements for visual inspection of containers managed as described above, we suggest that the professional engineer (PE) begin by consulting appropriate industry standards, such as those listed in Steel Tank Institute Standard SP001 and American Petroleum Institute Standard 653.[3] Similarly, in assessing whether a shop-built container is well designed, the PE may wish to consult industry standards such as Underwriters Laboratory 142 or American Petroleum Institute Standard 650, Appendix J. Where a facility is considering the use of the above approaches for containers that are currently resting on the ground, or have otherwise been managed in a way that presents risks for corrosion or are showing signs of corrosion, we recommend the facility first evaluate the condition of the

---

[1]Additionally, we recommend that special attention be paid to the characteristics of the material used for the support structure to ensure that they do not actually accelerate corrosion.

[2]Note, however, that a facility may not rely solely on measures that are required by other sections of the rule (e.g., secondary containment) to provide "equivalent environmental protection." Otherwise, the deviation provision would allow for approaches that provide a lesser degree of protection overall.

[3]Note that the Agency intends in the near future to develop guidance on appropriate visual inspection of shop-built containers. In that guidance, we intend to address issues such as inspection frequency, scope (e.g., internal and /or external), training and/or qualifications of persons conducting the inspections, and other measures that may be appropriate at a given site (e.g., measures to detect the presence of water in a container). We expect to use the referenced industry standards in developing such guidance.

It is also important to note, however, that depending on site circumstances, the appropriate requirements for visual inspection may exceed those normally conducted in accordance with recognized industry standards.

container in accordance with good engineering practices, including seeking expert advice, where appropriate.

Security

The SPCC regulations state that you must "fully fence each facility handling, processing, or storing oil, and lock and/or guard entrance gates when the facility is not in production or is unattended." 40 CFR §112.7(g)(1). You have asked whether two specific sets of circumstances would likely be determined to provide "equivalent environmental protection" to this requirement. The first is where the area of the facility directly involved in the handling, processing and storage of oil is adequately fenced. The second is where the facility is equipped with a "pump house" or "pump shack," which contains, among other appropriate things, a master disconnect switch from which all power to pumps and containers is cut off when the facility is unattended.

With respect to your first scenario, it is our view that, as a general matter, adequately fencing all discrete areas directly involved in the handling, processing and storage of oil would provide equivalent environmental protection to fencing the entire footprint of the facility, since it is potential for harm to this equipment that poses the risk addressed by the fencing requirement.

With respect to the second scenario, the approach you suggest would appear to generally provide environmental protection equivalent to fencing for risks associated with the potential for unauthorized access to pumping equipment. In other words, cutting off power in the manner you suggest would likely provide the added layer of protection offered by a fence should the other security measures offered by the rule, in this case 40 CFR §112.7(g)(3)'s requirements for securing pumps, fail. However, because cutting off power as suggested does not address risks to containers, piping and appurtenances not associated with the pumps at the facility, it does not appear to provide protection equivalent to fencing as it relates to risks to such equipment.

Conclusion

Please note that determinations of "equivalent environmental protection" must be implemented and documented in accordance with 40 CFR §112.7(a)(2). In addition, please be aware that the conclusions drawn in this letter are only for the purposes of meeting the "environmental equivalence" standard in the SPCC regulation. PE's might nevertheless decide to recommend non-destructive shell testing and fencing of the entire footprint of the facility for reasons other than compliance with the SPCC rule (e.g., to protect an owner's investment in equipment or to meet other local, state or federal requirements).

Finally, this letter is meant to provide guidance on the “equivalent environmental protection” standard. It does not, however, substitute for EPA's statutes or regulations, nor does it itself constitute a regulation. Thus, it cannot impose legally-binding requirements on EPA, States, or the regulated community, and its recommendations may not be appropriate at an individual site based on site-specific circumstances.

Sincerely,

Marianne Larmont Horinko
Assistant Administrator

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C. 20460

NOV 7 2006

OFFICE OF
SOLID WASTE AND
EMERGENCY RESPONSE

Mr. Brian Jennings, Executive Vice President
American Coalition for Ethanol
2500 S. Minnesota Ave, #200
Sioux Falls, SD 57105

Dear Mr. Jennings:

The purpose of this letter is to respond to your September 26 correspondence concerning the applicability of the U.S. EPA's Facility Response Plan (FRP) regulations to ethanol production and storage facilities and whether denatured ethanol is an "oil." We appreciate your concerns for prevention of oil spills to the environment and trust that this response will clarify EPA's position. Please note that although EPA works closely with the U.S. Department of Transportation (DOT) and the U.S. Coast Guard (USCG) in oil spill prevention, preparedness, and response, we can only address those facilities and regulations under our jurisdiction in response to your concerns.

As you indicated, EPA 40 CFR Parts 112.20 and 112.21 require facilities that exceed certain oil storage capacity thresholds and that because of their location could reasonably be expected to cause substantial harm to the environment by discharging into or on navigable waters, adjoining shorelines, or the exclusive economic zone, to prepare and submit an FRP. Inspectors from EPA's Region 8 recently visited five ethanol production facilities and found that four require an FRP because their total oil storage capacity exceeds the one million gallon threshold and they meet one or more of the substantial harm criteria at 40 CFR Part 112.20(f)(1). Two of the four have already submitted FRPs to the Region. The remaining two facilities elected to modify their process operations such that each facility's total oil storage capacity would fall below the applicable threshold, and thus, would no longer be subject to the FRP requirements.

One of the key factors driving FRP applicability is total oil storage capacity. You requested that EPA clarify that storage tanks containing denatured ethanol are not to be included when determining whether a facility exceeds the FRP total oil storage capacity threshold. However, this depends on the denaturant and whether it is an oil. If a facility uses gasoline as the denaturant, which is defined as a "petroleum oil" in 40 CFR Part 112.2, then the "storage capacity" defined in Part 112.2 is "the shell capacity of the container." Therefore, any containers used to store oil or fluids that include oil would need to be considered when determining whether a facility's overall oil storage capacity exceeds the FRP applicability threshold. Although the DOT regulations at 49 CFR 130.2(c)(1) provide for an oil concentration threshold of 10% for containment and response planning requirements applicable to transportation of oil by motor vehicles and rolling stock, there is no *de minimis* oil concentration in EPA's definition of oil for facilities in its jurisdiction, other than the determination that the oil could reasonably be expected

Internet Address (URL) ● http://www.epa.gov
Recycled/Recyclable ● Printed with Vegetable Oil Based Inks on 100% Postconsumer, Process Chlorine Free Recycled Paper

to be discharged to navigable waters in quantities that may be harmful, as described in 40 CFR 110.3 (violates water quality standards or causes a sheen).

In summary, once the determination is made that oil at a facility could reasonably be expected to be discharged to navigable water in quantities that may be harmful then, because gasoline is an oil, tanks storing ethanol denatured with 5% gasoline are oil tanks and the shell capacity of such tanks must be included in the facility's total oil storage capacity when determining applicability under 40 CFR Part 112, including the FRP requirements.

If you have any further questions on this issue, please contact Craig Matthiessen, Director of the Regulation and Policy Development Division in the Office of Emergency Management at 202-564-8016.

Sincerely,

Susan Parker Bodine
Assistant Administrator

Clean Water Act Jurisdiction Following the U.S. Supreme Court's Decision in Rapanos v. United States & Carabell v. United States

This memorandum[1] provides guidance to EPA regions and U.S. Army Corps of Engineers ["Corps"] districts implementing the Supreme Court's decision in the consolidated cases Rapanos v. United States and Carabell v. United States[2] (herein referred to simply as "Rapanos") which address the jurisdiction over waters of the United States under the Clean Water Act.[3] The chart below summarizes the key points contained in this memorandum. This reference tool is not a substitute for the more complete discussion of issues and guidance furnished throughout the memorandum.

Summary of Key Points

The agencies will assert jurisdiction over the following waters:

- **Traditional navigable waters**
- **Wetlands adjacent to traditional navigable waters**
- **Non-navigable tributaries of traditional navigable waters that are relatively permanent where the tributaries typically flow year-round or have continuous flow at least seasonally (e.g., typically three months)**
- **Wetlands that directly abut such tributaries**

The agencies will decide jurisdiction over the following waters based on a fact-specific analysis to determine whether they have a significant nexus with a traditional navigable water:

- **Non-navigable tributaries that are not relatively permanent**
- **Wetlands adjacent to non-navigable tributaries that are not relatively permanent**
- **Wetlands adjacent to but that do not directly abut a relatively permanent non-navigable tributary**

The agencies generally will not assert jurisdiction over the following features:

- **Swales or erosional features (e.g., gullies, small washes characterized by low volume, infrequent, or short duration flow)**
- **Ditches (including roadside ditches) excavated wholly in and draining only uplands and that do not carry a relatively permanent flow of water**

The agencies will apply the significant nexus standard as follows:

- **A significant nexus analysis will assess the flow characteristics and functions of the tributary itself and the functions performed by all wetlands adjacent to the tributary to determine if they significantly affect the chemical, physical and biological integrity of downstream traditional navigable waters**
- **Significant nexus includes consideration of hydrologic and ecologic factors**

[1] This guidance incorporates revisions to the EPA/Army Memorandum originally issued on June 6, 2007, after careful consideration of public comments received and based on the agencies' experience in implementing the *Rapanos* decision.
[2] 126 S. Ct. 2208 (2006).
[3] 33 U.S.C. §1251 et seq.

Background

Congress enacted the Clean Water Act ("CWA" or "the Act") "to restore and maintain the chemical, physical, and biological integrity of the Nation's waters."[4] One of the mechanisms adopted by Congress to achieve that purpose is a prohibition on the discharge of any pollutants, including dredged or fill material, into "navigable waters" except in compliance with other specified sections of the Act.[5] In most cases, this means compliance with a permit issued pursuant to CWA §402 or §404. The Act defines the term "discharge of a pollutant" as "any addition of any pollutant to navigable waters from any point source[,]"[6] and provides that "[t]he term 'navigable waters' means the waters of the United States, including the territorial seas[,]." [7]

In Rapanos, the Supreme Court addressed where the Federal government can apply the Clean Water Act, specifically by determining whether a wetland or tributary is a "water of the United States." The justices issued five separate opinions in Rapanos (one plurality opinion, two concurring opinions, and two dissenting opinions), with no single opinion commanding a majority of the Court.

The Rapanos Decision

Four justices, in a plurality opinion authored by Justice Scalia, rejected the argument that the term "waters of the United States" is limited to only those waters that are navigable in the traditional sense and their abutting wetlands.[8] However, the plurality concluded that the agencies' regulatory authority should extend only to "relatively permanent, standing or continuously flowing bodies of water" connected to traditional navigable waters, and to "wetlands with a continuous surface connection to" such relatively permanent waters.[9]

Justice Kennedy did not join the plurality's opinion but instead authored an opinion concurring in the judgment vacating and remanding the cases to the Sixth Circuit Court of Appeals.[10] Justice Kennedy agreed with the plurality that the statutory term "waters of the United States" extends beyond water bodies that are traditionally considered navigable.[11] Justice Kennedy, however, found the plurality's interpretation of the scope of the CWA to be "inconsistent with the Act's text, structure, and purpose[,]" and he instead presented a different standard for evaluating CWA jurisdiction over wetlands and other water bodies.[12] Justice Kennedy concluded that wetlands are "waters

---

[4] 33 U.S.C. § 1251(a).
[5] 33 U.S.C. § 1311(a), §1362(12)(A).
[6] 33 U.S.C. § 1362(12)(A)
[7] 33 U.S.C. § 1362(7). See also 33 C.F.R. § 328.3(a) and 40 C.F.R. § 230.3(s).
[8] Id. at 2220.
[9] Id. at 2225-27.
[10] Id. at 2236-52. While Justice Kennedy concurred in the Court's decision to vacate and remand the cases to the Sixth Circuit, his basis for remand was limited to the question of "whether the specific wetlands at issue possess a significant nexus with navigable waters." 126 S. Ct. at 2252. In contrast, the plurality remanded the cases to determine both "whether the ditches and drains near each wetland are 'waters,'" and "whether the wetlands in question are 'adjacent' to these 'waters' in the sense of possessing a continuous surface connection…." Id. at 2235.
[11] Id. at 2241.
[12] Id. at 2246.

of the United States" "if the wetlands, either alone or in combination with similarly situated lands in the region, significantly affect the chemical, physical, and biological integrity of other covered waters more readily understood as 'navigable.' When, in contrast, wetlands' effects on water quality are speculative or insubstantial, they fall outside the zone fairly encompassed by the statutory term 'navigable waters.'"[13]

Four justices, in a dissenting opinion authored by Justice Stevens, concluded that EPA's and the Corps' interpretation of "waters of the United States" was a reasonable interpretation of the Clean Water Act.[14]

When there is no majority opinion in a Supreme Court case, controlling legal principles may be derived from those principles espoused by five or more justices.[15] Thus, regulatory jurisdiction under the CWA exists over a water body if either the plurality's or Justice Kennedy's standard is satisfied.[16] Since Rapanos, the United States has filed pleadings in a number of cases interpreting the decision in this manner.

The agencies are issuing this memorandum in recognition of the fact that EPA regions and Corps districts need guidance to ensure that jurisdictional determinations, permitting actions, and other relevant actions are consistent with the decision and supported by the administrative record. Therefore, the agencies have evaluated the Rapanos opinions to identify those waters that are subject to CWA jurisdiction under the reasoning of a majority of the justices. This approach is appropriate for a guidance document. The agencies will continue to monitor implementation of the Rapanos decision in the field and recognize that further consideration of jurisdictional issues, including clarification and definition of key terminology, may be appropriate in the future, either through issuance of additional guidance or through rulemaking.

---

[13] Id. at 2248. Chief Justice Roberts wrote a separate concurring opinion explaining his agreement with the plurality. See 126 S. Ct. at 2235-36.

[14] Id. at 2252-65. Justice Breyer wrote a separate dissenting opinion explaining his agreement with Justice Stevens' dissent. See 126 S. Ct. at 2266.

[15] See Marks v. United States, 430 U.S. 188, 193-94 (1977); Waters v. Churchill, 511 U.S. 661, 685 (1994) (Souter, J., concurring) (analyzing the points of agreement between plurality, concurring, and dissenting opinions to identify the legal "test ... that lower courts should apply," under Marks, as the holding of the Court); cf. League of United Latin American Citizens v. Perry, 126 S. Ct. 2594, 2607 (2006) (analyzing concurring and dissenting opinions in a prior case to identify a legal conclusion of a majority of the Court); Alexander v. Sandoval, 532 U.S. 275, 281-282 (2001) (same).

[16] 126 S. Ct. at 2265 (Stevens, J., dissenting) ("Given that all four justices who have joined this opinion would uphold the Corps' jurisdiction in both of these cases – and in all other cases in which either the plurality's or Justice Kennedy's test is satisfied – on remand each of the judgments should be reinstated if *either* of those tests is met.") (emphasis in original). The agencies recognize that the Eleventh Circuit, in United States v. McWane, Inc., et al., 505 F.3d 1208 (11th Cir. 2007), has concluded that the Kennedy standard is the sole method of determining CWA jurisdiction in that Circuit. The Supreme Court denied the government's petition for a writ of *certiorari* on December 1, 2008.

Agency Guidance[17]

To ensure that jurisdictional determinations, administrative enforcement actions, and other relevant agency actions are consistent with the Rapanos decision, the agencies in this guidance address which waters are subject to CWA § 404 jurisdiction.[18] Specifically, this guidance identifies those waters over which the agencies will assert jurisdiction categorically and on a case-by-case basis, based on the reasoning of the Rapanos opinions.[19] EPA and the Corps will continually assess and review the application of this guidance to ensure nationwide consistency, reliability, and predictability in our administration of the statute.

1. Traditional Navigable Waters (i.e.,"(a)(1) Waters") and Their Adjacent Wetlands

Key Points

- **The agencies will assert jurisdiction over traditional navigable waters, which includes all the waters described in 33 C.F.R. § 328.3(a)(1), and 40 C.F.R. § 230.3 (s)(1).**
- **The agencies will assert jurisdiction over wetlands adjacent to traditional navigable waters, including over adjacent wetlands that do not have a continuous surface connection to traditional navigable waters.**

EPA and the Corps will continue to assert jurisdiction over "[a]ll waters which are currently used, or were used in the past, or may be susceptible to use in interstate or

[17] The CWA provisions and regulations described in this document contain legally binding requirements. This guidance does not substitute for those provisions or regulations, nor is it a regulation itself. It does not impose legally binding requirements on EPA, the Corps, or the regulated community, and may not apply to a particular situation depending on the circumstances. Any decisions regarding a particular water will be based on the applicable statutes, regulations, and case law. Therefore, interested persons are free to raise questions about the appropriateness of the application of this guidance to a particular situation, and EPA and/or the Corps will consider whether or not the recommendations or interpretations of this guidance are appropriate in that situation based on the statutes, regulations, and case law.

[18] This guidance focuses only on those provisions of the agencies' regulations at issue in Rapanos -- 33 C.F.R. §§ 328.3(a)(1), (a)(5), and (a)(7); 40 C.F.R. §§ 230.3(s)(1), (s)(5), and (s)(7). This guidance does not address or affect other subparts of the agencies' regulations, or response authorities, relevant to the scope of jurisdiction under the CWA. In addition, because this guidance is issued by both the Corps and EPA, which jointly administer CWA § 404, it does not discuss other provisions of the CWA, including §§ 311 and 402, that differ in certain respects from § 404 but share the definition of "waters of the United States." Indeed, the plurality opinion in Rapanos noted that "... there is no reason to suppose that our construction today significantly affects the enforcement of §1342 ... The Act does not forbid the 'addition of any pollutant *directly* to navigable waters from any point source,' but rather the 'addition of any pollutant *to* navigable waters.'" (emphasis in original) 126 S. Ct. 2208, 2227. EPA is considering whether to provide additional guidance on these and other provisions of the CWA that may be affected by the Rapanos decision.

[19] In 2001, the Supreme Court held that use of "isolated" non-navigable intrastate waters by migratory birds was not by itself a sufficient basis for the exercise of federal regulatory jurisdiction under the CWA. See Solid Waste Agency of Northern Cook County (SWANCC) v. U.S. Army Corps of Engineers, 531 U.S. 159 (2001). This guidance does not address SWANCC, nor does it affect the Joint Memorandum regarding that decision issued by the General Counsels of EPA and the Department of the Army on January 10, 2003. See 68 Fed. Reg. 1991, 1995 (Jan. 15, 2003).

foreign commerce, including all waters which are subject to the ebb and flow of the tide."[20] These waters are referred to in this guidance as traditional navigable waters.

The agencies will also continue to assert jurisdiction over wetlands "adjacent" to traditional navigable waters as defined in the agencies' regulations. Under EPA and Corps regulations and as used in this guidance, "adjacent" means "bordering, contiguous, or neighboring." Finding a continuous surface connection is not required to establish adjacency under this definition. The Rapanos decision does not affect the scope of jurisdiction over wetlands that are adjacent to traditional navigable waters because at least five justices agreed that such wetlands are "waters of the United States."[21]

The regulations define "adjacent" as follows: "The term *adjacent* means bordering, contiguous, or neighboring. Wetlands separated from other waters of the United States by man-made dikes or barriers, natural river berms, beach dunes and the like are 'adjacent wetlands.'"[22] Under this definition, the agencies consider wetlands adjacent if one of following three criteria is satisfied. First, there is an unbroken surface or shallow sub-surface connection to jurisdictional waters. This hydrologic connection may be intermittent. Second, they are physically separated from jurisdictional waters by man-made dikes or barriers, natural river berms, beach dunes, and the like. Or third, their proximity to a jurisdictional water is reasonably close, supporting the science-based

---

[20] 33 C.F.R. § 328.3(a)(1); 40 C.F.R. § 230.3(s)(1). The "(a)(1)" waters include all of the "navigable waters of the United States," defined in 33 C.F.R. Part 329 and by numerous decisions of the federal courts, plus all other waters that are navigable-in-fact (e.g., the Great Salt Lake, UT and Lake Minnetonka MN). For purposes of CWA jurisdiction and this guidance, waters will be considered traditional navigable waters if:

- They are subject to Section 9 or 10 of the Rivers and Harbors Act, or
- A federal court has determined that the water body is navigable-in-fact under federal law, or
- They are waters currently being used for commercial navigation, including commercial water-borne recreation (e.g., boat rentals, guided fishing trips, water ski tournaments, etc.), or
- They have historically been used for commercial navigation, including commercial water-borne recreation; or
- They are susceptible to being used in the future for commercial navigation, including commercial water-borne recreation. Susceptibility for future use may be determined by examining a number of factors, including the physical characteristics and capacity of the water (e.g., size, depth, and flow velocity, etc.) to be used in commercial navigation, including commercial recreational navigation, and the likelihood of future commercial navigation or commercial water-borne recreation. Evidence of future commercial navigation use, including commercial water-borne recreation (e.g., development plans, plans for water dependent events, etc.), must be clearly documented. Susceptibility to future commercial navigation, including commercial water-borne recreation, will not be supported when the evidence is insubstantial or speculative. Use of average flow statistics may not accurately represent streams with "flashy" flow characteristics. In such circumstances, daily gage data is more representative of flow characteristics.

[21] Id. at 2248 (Justice Kennedy, concurring) ("As applied to wetlands adjacent to navigable-in-fact waters, the Corps' conclusive standard for jurisdiction rests upon a reasonable inference of ecologic interconnection, and the assertion of jurisdiction for those wetlands is sustainable under the Act by showing adjacency alone.").

[22] 33 C.F.R. § 328.3(c).

inference that such wetlands have an ecological interconnection with jurisdictional waters.[23] Because of the scientific basis for this inference, determining whether a wetland is reasonably close to a jurisdictional water does not generally require a case-specific demonstration of an ecologic interconnection. In the case of a jurisdictional water and a reasonably close wetland, such implied ecological interconnectivity is neither speculative nor insubstantial. For example, species, such as amphibians or anadramous and catadramous fish, move between such waters for spawning and their life stage requirements. Migratory species, however, shall not be used to support an ecologic interconnection. In assessing whether a wetland is reasonably close to a jurisdictional water, the proximity of the wetland (including all parts of a single wetland that has been divided by road crossings, ditches, berms, etc.) in question will be evaluated and shall not be evaluated together with other wetlands in the area.

2. Relatively Permanent Non-navigable Tributaries of Traditional Navigable Waters and Wetlands with a Continuous Surface Connection with Such Tributaries

Key Points

- **The agencies will assert jurisdiction over non-navigable tributaries of traditional navigable waters that are relatively permanent where the tributaries typically flow year-round or have continuous flow at least seasonally (e.g., typically three months).**
- **The agencies will assert jurisdiction over those adjacent wetlands that have a continuous surface connection to such tributaries (e.g., they are not separated by uplands, a berm, dike, or similar feature.)**

A non-navigable tributary[24]of a traditional navigable water is a non-navigable water body whose waters flow into a traditional navigable water either directly or indirectly by means of other tributaries. Both the plurality opinion and the dissent would uphold CWA jurisdiction over non-navigable tributaries that are "relatively permanent" – waters that typically (e.g., except due to drought) flow year-round or waters that have a

[23] See e.g., United States v. Riverside Bayview Homes, Inc., 474 U.S. 121, 134 (1985) ("...the Corps' ecological judgment about the relationship between waters and their adjacent wetlands provides an adequate basis for a legal judgment that adjacent wetlands may be defined as waters under the Act.").

[24] A tributary includes natural, man-altered, or man-made water bodies that carry flow directly or indirectly into a traditional navigable water. Furthermore, a tributary, for the purposes of this guidance, is the entire reach of the stream that is of the same order (i.e., from the point of confluence, where two lower order streams meet to form the tributary, downstream to the point such tributary enters a higher order stream). The flow characteristics of a particular tributary generally will be evaluated at the farthest downstream limit of such tributary (i.e., the point the tributary enters a higher order stream). However, for purposes of determining whether the tributary is relatively permanent, where data indicates the flow regime at the downstream limit is not representative of the entire tributary (as described above) (e.g., where data indicates the tributary is relatively permanent at its downstream limit but not for the majority of its length, or vice versa), the flow regime that best characterizes the entire tributary should be used. A primary factor in making this determination is the relative lengths of segments with differing flow regimes. It is reasonable for the agencies to treat the entire tributary in light of the Supreme Court's observation that the phrase "navigable waters" generally refers to "rivers, streams, and other hydrographic features." 126 S. Ct. at 2222 (Justice Scalia, quoting Riverside Bayview, 474 U.S. at 131). The entire reach of a stream is a reasonably identifiable hydrographic feature. The agencies will also use this characterization of tributary when applying the significant nexus standard under Section 3 of this guidance.

continuous flow at least seasonally (e.g., typically three months).[25] Justice Scalia emphasizes that relatively permanent waters do not include tributaries "whose flow is 'coming and going at intervals ... broken, fitful.'"[26] Therefore, "relatively permanent" waters do not include ephemeral tributaries which flow only in response to precipitation and intermittent streams which do not typically flow year-round or have continuous flow at least seasonally. However, CWA jurisdiction over these waters will be evaluated under the significant nexus standard described below. The agencies will assert jurisdiction over relatively permanent non-navigable tributaries of traditional navigable waters without a legal obligation to make a significant nexus finding.

In addition, the agencies will assert jurisdiction over those adjacent wetlands that have a continuous surface connection with a relatively permanent, non-navigable tributary, without the legal obligation to make a significant nexus finding. As explained above, the plurality opinion and the dissent agree that such wetlands are jurisdictional.[27] The plurality opinion indicates that "continuous surface connection" is a "physical connection requirement."[28] Therefore, a continuous surface connection exists between a wetland and a relatively permanent tributary where the wetland directly abuts the tributary (e.g., they are not separated by uplands, a berm, dike, or similar feature).[29]

---

[25] See 126 S. Ct. at 2221 n. 5 (Justice Scalia, plurality opinion) (explaining that "relatively permanent" does not necessarily exclude waters "that might dry up in extraordinary circumstances such as drought" or "seasonal rivers, which contain continuous flow during some months of the year but no flow during dry months").

[26] Id. (internal citations omitted)

[27] Id. at 2226-27 (Justice Scalia, plurality opinion).

[28] Id. at 2232 n.13 (referring to "our physical-connection requirement" and later stating that Riverside Bayview does not reject "the physical-connection requirement") and 2234 ("Wetlands are 'waters of the United States' if they bear the 'significant nexus' of physical connection, which makes them as a practical matter *indistinguishable* from waters of the United States.") (emphasis in original). See also 126 S. Ct. at 2230 ("adjacent" means "physically abutting") and 2229 (citing to Riverside Bayview as "confirm[ing] that the scope of ambiguity of 'the waters of the United States' is determined by a wetland's *physical connection* to covered waters…") (emphasis in original). A continuous surface connection does not require surface water to be continuously present between the wetland and the tributary. 33 C.F.R. § 328.3(b) and 40 C.F.R. § 232.2 (defining wetlands as "those areas that are inundated or saturated by surface or ground water at a frequency and duration sufficient to support … a prevalence of vegetation typically adapted for life in saturated soil conditions").

[29] While all wetlands that meet the agencies' definitions are considered adjacent wetlands, only those adjacent wetlands that have a continuous surface connection because they directly abut the tributary (e.g., they are not separated by uplands, a berm, dike, or similar feature) are considered jurisdictional under the plurality standard.

3. Certain Adjacent Wetlands and Non-navigable Tributaries That Are Not Relatively Permanent

Key Points

- **The agencies will assert jurisdiction over non-navigable, not relatively permanent tributaries and their adjacent wetlands where such tributaries and wetlands have a significant nexus to a traditional navigable water.**
- **A significant nexus analysis will assess the flow characteristics and functions of the tributary itself and the functions performed by any wetlands adjacent to the tributary to determine if they significantly affect the chemical, physical and biological integrity of downstream traditional navigable waters.**
- **"Similarly situated" wetlands include all wetlands adjacent to the same tributary.**
- **Significant nexus includes consideration of hydrologic factors including the following:**
  - **volume, duration, and frequency of flow, including consideration of certain physical characteristics of the tributary**
  - **proximity to the traditional navigable water**
  - **size of the watershed**
  - **average annual rainfall**
  - **average annual winter snow pack**
- **Significant nexus also includes consideration of ecologic factors including the following:**
  - **potential of tributaries to carry pollutants and flood waters to traditional navigable waters**
  - **provision of aquatic habitat that supports a traditional navigable water**
  - **potential of wetlands to trap and filter pollutants or store flood waters**
  - **maintenance of water quality in traditional navigable waters**
- **The following geographic features generally are not jurisdictional waters:**
  - **swales or erosional features (e.g. gullies, small washes characterized by low volume, infrequent, or short duration flow)**
  - **ditches (including roadside ditches) excavated wholly in and draining only uplands and that do not carry a relatively permanent flow of water**

The agencies will assert jurisdiction over the following types of waters when they have a significant nexus with a traditional navigable water: (1) non-navigable tributaries that are not relatively permanent,[30] (2) wetlands adjacent to non-navigable tributaries that are not relatively permanent, and (3) wetlands adjacent to, but not directly abutting, a relatively permanent tributary (e.g., separated from it by uplands, a berm, dike or similar feature).[31] As described below, the agencies will assess the flow characteristics and functions of the tributary itself, together with the functions performed by any wetlands adjacent to that tributary, to determine whether collectively they have a significant nexus with traditional navigable waters.

[30] For simplicity, the term "tributary" when used alone in this section refers to non-navigable tributaries that are not relatively permanent.

[31] As described in Section 2 of this guidance, the agencies will assert jurisdiction, without the need for a significant nexus finding, over all wetlands that are both adjacent and have a continuous surface connection to relatively permanent tributaries. See pp. 6-7, supra.

The agencies' assertion of jurisdiction over non-navigable tributaries and adjacent wetlands that have a significant nexus to traditional navigable waters is supported by five justices. Justice Kennedy applied the significant nexus standard to the wetlands at issue in Rapanos and Carabell: "[W]etlands possess the requisite nexus, and thus come within the statutory phrase 'navigable waters,' if the wetlands, either alone or in combination with similarly situated lands in the region, significantly affect the chemical, physical, and biological integrity of other covered waters more readily understood as 'navigable.'"[32] While Justice Kennedy's opinion discusses the significant nexus standard primarily in the context of wetlands adjacent to non-navigable tributaries,[33] his opinion also addresses Clean Water Act jurisdiction over tributaries themselves. Justice Kennedy states that, based on the Supreme Court's decisions in Riverside Bayview and SWANCC, "the connection between a non-navigable water or wetland may be so close, or potentially so close, that the Corps may deem the water or wetland a 'navigable water' under the Act. ... Absent a significant nexus, jurisdiction under the Act is lacking."[34] Thus, Justice Kennedy would limit jurisdiction to those waters that have a significant nexus with traditional navigable waters, although his opinion focuses on the specific factors and functions the agencies should consider in evaluating significant nexus for adjacent wetlands, rather than for tributaries.

In considering how to apply the significant nexus standard, the agencies have focused on the integral relationship between the ecological characteristics of tributaries and those of their adjacent wetlands, which determines in part their contribution to restoring and maintaining the chemical, physical and biological integrity of the Nation's traditional navigable waters. The ecological relationship between tributaries and their adjacent wetlands is well documented in the scientific literature and reflects their physical proximity as well as shared hydrological and biological characteristics. The flow parameters and ecological functions that Justice Kennedy describes as most relevant to an evaluation of significant nexus result from the ecological inter-relationship between tributaries and their adjacent wetlands. For example, the duration, frequency, and volume of flow in a tributary, and subsequently the flow in downstream navigable waters, is directly affected by the presence of adjacent wetlands that hold floodwaters, intercept sheet flow from uplands, and then release waters to tributaries in a more even and constant manner. Wetlands may also help to maintain more consistent water temperature in tributaries, which is important for some aquatic species. Adjacent wetlands trap and hold pollutants that may otherwise reach tributaries (and downstream navigable waters) including sediments, chemicals, and other pollutants. Tributaries and their adjacent wetlands provide habitat (e.g., feeding, nesting, spawning, or rearing young) for many aquatic species that also live in traditional navigable waters.

---

[32] Id. at 2248. When applying the significant nexus standard to tributaries and wetlands, it is important to apply it within the limits of jurisdiction articulated in SWANCC. Justice Kennedy cites SWANCC with approval and asserts that the significant nexus standard, rather than being articulated for the first time in Rapanos, was established in SWANCC. 126 S. Ct. at 2246 (describing SWANCC as "interpreting the Act to require a significant nexus with navigable waters"). It is clear, therefore, that Justice Kennedy did not intend for the significant nexus standard to be applied in a manner that would result in assertion of jurisdiction over waters that he and the other justices determined were not jurisdictional in SWANCC. Nothing in this guidance should be interpreted as providing authority to assert jurisdiction over waters deemed non-jurisdictional by SWANCC.

[33] 126 S. Ct. at 2247-50.

[34] Id. at 2241 (emphasis added).

When performing a significant nexus analysis,[35] the first step is to determine if the tributary has any adjacent wetlands. Where a tributary has no adjacent wetlands, the agencies will consider the flow characteristics and functions of only the tributary itself in determining whether such tributary has a significant effect on the chemical, physical and biological integrity of downstream traditional navigable waters. A tributary, as characterized in Section 2 above, is the entire reach of the stream that is of the same order (i.e., from the point of confluence, where two lower order streams meet to form the tributary, downstream to the point such tributary enters a higher order stream). For purposes of demonstrating a connection to traditional navigable waters, it is appropriate and reasonable to assess the flow characteristics of the tributary at the point at which water is in fact being contributed to a higher order tributary or to a traditional navigable water. If the tributary has adjacent wetlands, the significant nexus evaluation needs to recognize the ecological relationship between tributaries and their adjacent wetlands, and their closely linked role in protecting the chemical, physical, and biological integrity of downstream traditional navigable waters.

Therefore, the agencies will consider the flow and functions of the tributary together with the functions performed by all the wetlands adjacent to that tributary in evaluating whether a significant nexus is present. Similarly, where evaluating significant nexus for an adjacent wetland, the agencies will consider the flow characteristics and functions performed by the tributary to which the wetland is adjacent along with the functions performed by the wetland and all other wetlands adjacent to that tributary. This approach reflects the agencies' interpretation of Justice Kennedy's term "similarly situated" to include all wetlands adjacent to the same tributary. Where it is determined that a tributary and its adjacent wetlands collectively have a significant nexus with traditional navigable waters, the tributary and all of its adjacent wetlands are jurisdictional. Application of the significant nexus standard in this way is reasonable because of its strong scientific foundation – that is, the integral ecological relationship between a tributary and its adjacent wetlands. Interpreting the phrase "similarly situated" to include all wetlands adjacent to the same tributary is reasonable because such wetlands are physically located in a like manner (i.e., lying adjacent to the same tributary).

Principal considerations when evaluating significant nexus include the volume, duration, and frequency of the flow of water in the tributary and the proximity of the tributary to a traditional navigable water. In addition to any available hydrologic information (e.g., gauge data, flood predictions, historic records of water flow, statistical data, personal observations/records, etc.), the agencies may reasonably consider certain physical characteristics of the tributary to characterize its flow, and thus help to inform the determination of whether or not a significant nexus is present between the tributary and downstream traditional navigable waters. Physical indicators of flow may include the presence and characteristics of a reliable ordinary high water mark (OHWM) with a channel defined by bed and banks.[36] Other physical indicators of flow may include

[35] In discussing the significant nexus standard, Justice Kennedy stated: "The required nexus must be assessed in terms of the statute's goals and purposes. Congress enacted the [CWA] to 'restore and maintain the chemical, physical, and biological integrity of the Nation's waters' ..." 126 S. Ct. at 2248. Consistent with Justice Kennedy's instruction, EPA and the Corps will apply the significant nexus standard in a manner that restores and maintains any of these three attributes of traditional navigable waters.

[36] See 33 C.F.R. § 328.3(e). The OHWM also serves to define the lateral limit of jurisdiction in a non-navigable tributary where there are no adjacent wetlands. See 33 C.F.R. § 328.4(c). While EPA regions

shelving, wracking, water staining, sediment sorting, and scour.[37] Consideration will also be given to certain relevant contextual factors that directly influence the hydrology of tributaries including the size of the tributary's watershed, average annual rainfall, average annual winter snow pack, slope, and channel dimensions.

In addition, the agencies will consider other relevant factors, including the functions performed by the tributary together with the functions performed by any adjacent wetlands. One such factor is the extent to which the tributary and adjacent wetlands have the capacity to carry pollutants (e.g., petroleum wastes, toxic wastes, sediment) or flood waters to traditional navigable waters, or to reduce the amount of pollutants or flood waters that would otherwise enter traditional navigable waters.[38] The agencies will also evaluate ecological functions performed by the tributary and any adjacent wetlands which affect downstream traditional navigable waters, such as the capacity to transfer nutrients and organic carbon vital to support downstream foodwebs (e.g., macroinvertebrates present in headwater streams convert carbon in leaf litter making it available to species downstream), habitat services such as providing spawning areas for recreationally or commercially important species in downstream waters, and the extent to which the tributary and adjacent wetlands perform functions related to maintenance of downstream water quality such as sediment trapping.

After assessing the flow characteristics and functions of the tributary and its adjacent wetlands, the agencies will evaluate whether the tributary and its adjacent wetlands are likely to have an effect that is more than speculative or insubstantial on the chemical, physical, and biological integrity of a traditional navigable water. As the distance from the tributary to the navigable water increases, it will become increasingly important to document whether the tributary and its adjacent wetlands have a significant nexus rather than a speculative or insubstantial nexus with a traditional navigable water.

Accordingly, Corps districts and EPA regions shall document in the administrative record the available information regarding whether a tributary and its adjacent wetlands have a significant nexus with a traditional navigable water, including the physical indicators of flow in a particular case and available information regarding the functions of the tributary and any adjacent wetlands. The agencies will explain their basis for concluding whether or not the tributary and its adjacent wetlands, when considered together, have a more than speculative or insubstantial effect on the chemical, physical, and biological integrity of a traditional navigable water.

Swales or erosional features (e.g., gullies, small washes characterized by low volume, infrequent, or short duration flow) are generally not waters of the United States

---

and Corps districts must exercise judgment to identify the OHWM on a case-by-case basis, the Corps' regulations identify the factors to be applied. These regulations have recently been further explained in Regulatory Guidance Letter (RGL) 05-05 (Dec. 7, 2005). The agencies will apply the regulations and the RGL and take other steps as needed to ensure that the OHWM identification factors are applied consistently nationwide.

[37] See Justice Kennedy's discussion of "physical characteristics," 126 S. Ct. at 2248-2249.

[38] See, generally, 126 S. Ct. at 2248-53; see also 126 S. Ct. at 2249 ("Just as control over the non-navigable parts of a river may be essential or desirable in the interests of the navigable portions, so may the key to flood control on a navigable stream be found in whole or in part in flood control on its tributaries….") (citing to Oklahoma ex rel. Phillips v. Guy F. Atkinson Co., 313 U.S. 508, 524-25(1941)).

because they are not tributaries or they do not have a significant nexus to downstream traditional navigable waters. In addition, ditches (including roadside ditches) excavated wholly in and draining only uplands and that do not carry a relatively permanent flow of water are generally not waters of the United States because they are not tributaries or they do not have a significant nexus to downstream traditional navigable waters.[39] Even when not jurisdictional waters subject to CWA §404, these geographic features (e.g., swales, ditches) may still contribute to a surface hydrologic connection between an adjacent wetland and a traditional navigable water. In addition, these geographic features may function as point sources (i.e., "discernible, confined, and discrete conveyances"), such that discharges of pollutants to other waters through these features could be subject to other CWA regulations (e.g., CWA §§ 311 and 402).[40]

Certain ephemeral waters in the arid west are distinguishable from the geographic features described above where such ephemeral waters are tributaries and they have a significant nexus to downstream traditional navigable waters. For example, in some cases these ephemeral tributaries may serve as a transitional area between the upland environment and the traditional navigable waters. During and following precipitation events, ephemeral tributaries collect and transport water and sometimes sediment from the upper reaches of the landscape downstream to the traditional navigable waters. These ephemeral tributaries may provide habitat for wildlife and aquatic organisms in downstream traditional navigable waters. These biological and physical processes may further support nutrient cycling, sediment retention and transport, pollutant trapping and filtration, and improvement of water quality, functions that may significantly affect the chemical, physical, and biological integrity of downstream traditional navigable waters.

Documentation

As described above, the agencies will assert CWA jurisdiction over the following waters without the legal obligation to make a significant nexus determination: traditional navigable waters and wetlands adjacent thereto, non-navigable tributaries that are relatively permanent waters, and wetlands with a continuous surface connection with such tributaries. The agencies will also decide CWA jurisdiction over other non-navigable tributaries and over other wetlands adjacent to non-navigable tributaries based on a fact-specific analysis to determine whether they have a significant nexus with traditional navigable waters. For purposes of CWA §404 determinations by the Corps, the Corps and EPA are developing a revised form to be used by field regulators for documenting the assertion or declination of CWA jurisdiction.

Corps districts and EPA regions will ensure that the information in the record adequately supports any jurisdictional determination. The record shall, to the maximum extent practicable, explain the rationale for the determination, disclose the data and information relied upon, and, if applicable, explain what data or information received greater or lesser weight, and what professional judgment or assumptions were used in reaching the determination. The Corps districts and EPA regions will also demonstrate and document in the record that a particular water either fits within a class identified above as not requiring a significant nexus determination, or that the water has a

[39] See 51 Fed. Reg. 41206, 41217 (Nov. 13, 1986).
[40] 33 U.S.C. § 1362(14).

significant nexus with a traditional navigable water. As a matter of policy, Corps districts and EPA regions will include in the record any available information that documents the existence of a significant nexus between a relatively permanent tributary that is not perennial (and its adjacent wetlands if any) and a traditional navigable water, even though a significant nexus finding is not required as a matter of law.

All pertinent documentation and analyses for a given jurisdictional determination (including the revised form) shall be adequately reflected in the record and clearly demonstrate the basis for asserting or declining CWA jurisdiction.[41] Maps, aerial photography, soil surveys, watershed studies, local development plans, literature citations, and references from studies pertinent to the parameters being reviewed are examples of information that will assist staff in completing accurate jurisdictional determinations. The level of documentation may vary among projects. For example, jurisdictional determinations for complex projects may require additional documentation by the project manager.

Benjamin H. Grumbles
Assistant Administrator for Water
U.S. Environmental Protection Agency

John Paul Woodley, Jr.
Assistant Secretary of the Army
(Civil Works)
Department of the Army

[41] For jurisdictional determinations and permitting decisions, such information shall be posted on the appropriate Corps website for public and interagency information.

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C. 20460

OFFICE OF
SOLID WASTE AND
EMERGENCY RESPONSE

December 10, 2010

American Petroleum Institute
ATTN: Roger Claff, P.E.
Sr. Scientific Advisor
1220 L Street, Northwest
Washington, DC 20005-4070
(SENT VIA EMAIL)

RE: SPCC concerns related to gas plants

Dear Roger,

Thank you and the members of the API upstream SPCC committee for taking the time to meet with my staff on November 10, 2010 to discuss concerns raised in your June 28, 2010 letter. I also appreciate your willingness to provide my staff additional time to address your letter and concerns in light of the unprecedented resource impacts the Deep Water Horizon incident had on our office. The meeting was timely; as it provides a year until the compliance date arrives to further clarify any applicability concerns for facility specific SPCC provisions regarding gas plants/compression stations.

As discussed in the meeting and in comments my staff provided to the *API Bulletin D-16* document submitted April 28, 2010, gas plants are generally not considered oil production facilities under the SPCC rule and are therefore subject to the facility specific requirements under 40 CFR part 112.8 rather than 112.9. Although not specifically addressed in your letter, you also raised concerns regarding gas compression stations and the applicability of the facility specific SPCC requirements. As with gas plants, gas compression stations are not generally considered oil production facilities under the SPCC rule and are therefore subject to the facility specific requirements under 40 CFR part 112.8 rather than 112.9.

We share your concerns about providing a consistent interpretation of the rule with regard to the applicability of facility specific SPCC requirements at gas plants. We have discussed the application of the facility specific requirements to gas plant and compression stations with regional office personnel, and are confident inspection personnel are consistently interpreting the

Internet Address (URL) • http://www.epa.gov
Recycled/Recyclable • Printed with Vegetable Oil Based Inks on 100% Postconsumer, Process Chlorine Free Recycled Paper

regulation as described above. With almost a year to work collaboratively on guidance on this issue, we look forward to working with you on text and examples that address site specific issues which may be incorporated into the *API Bulletin D-16* document and/or future EPA guidance.

Again, thank you for bringing your concern to our attention. Please call Mark W. Howard at 202-564-1964 with any questions.

Sincerely;

R. Craig Matthiessen

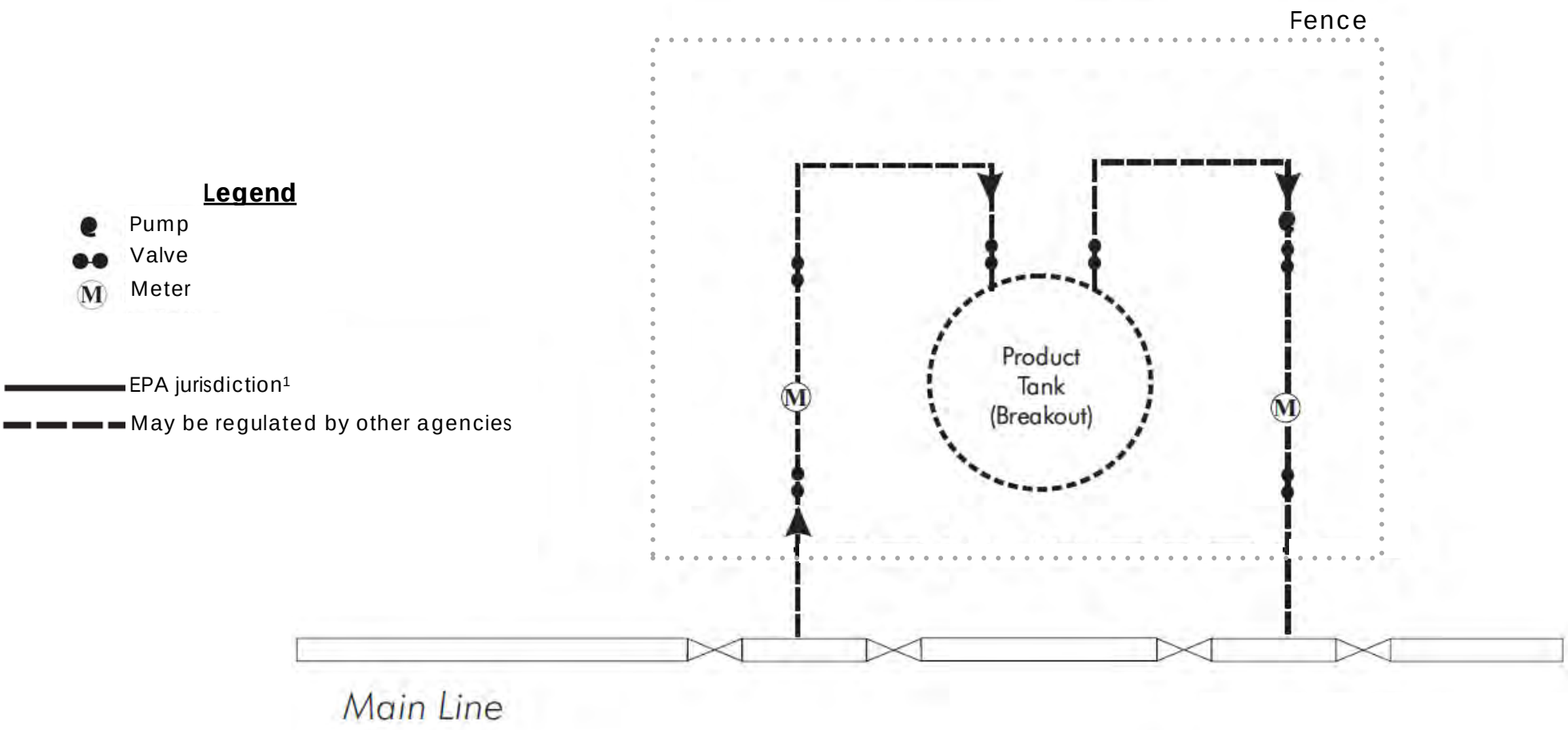
R. Craig Matthiessen, PE, FAIChE
Director
Regulation and Policy Development Division

CC: Regional Oil Program Managers
James Bove, OGC
David Drelich, OECA

EPA JURISDICTION AT COMPLEXES

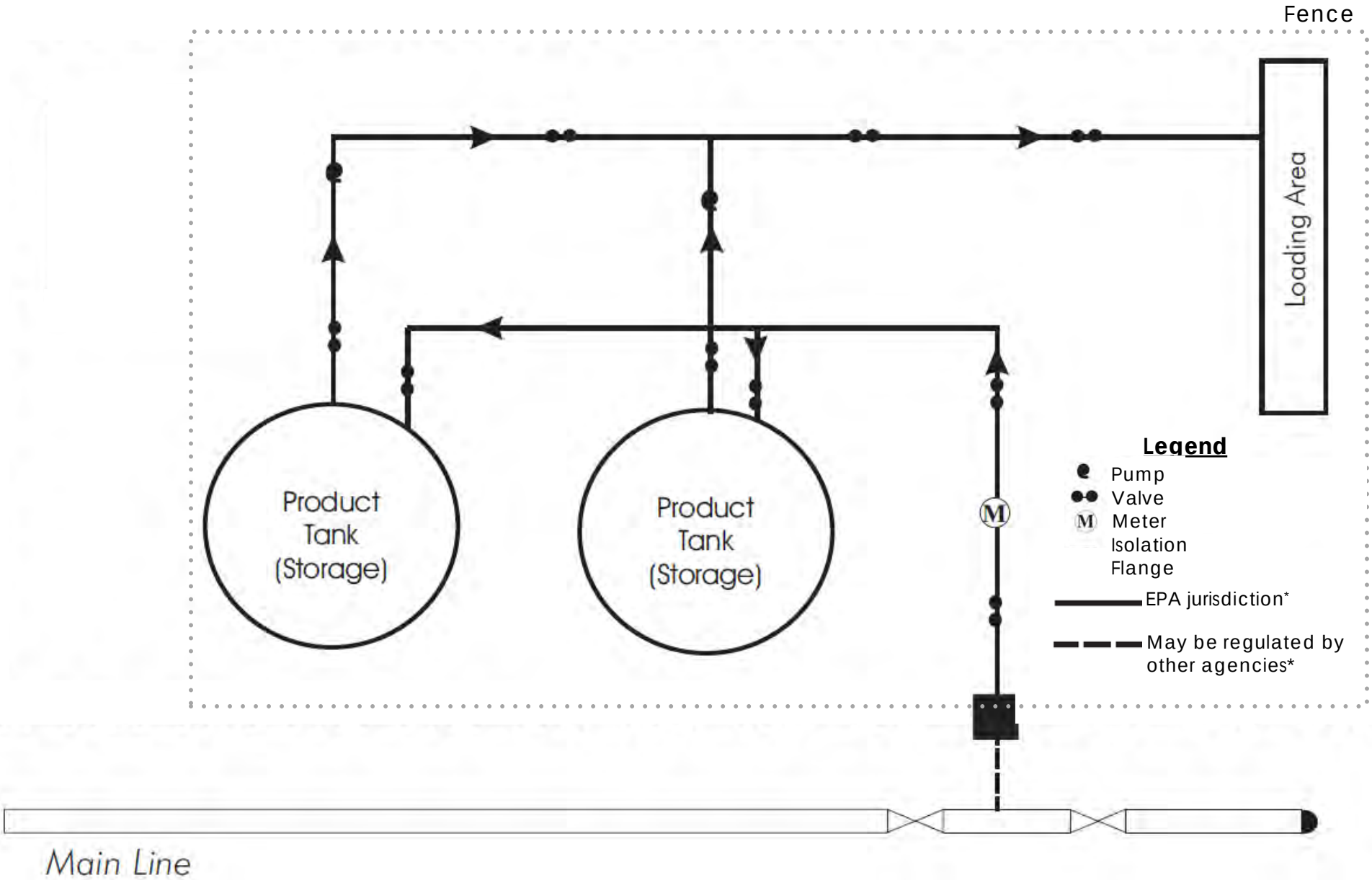
8/23/2013

BREAKOUT TANKAGE

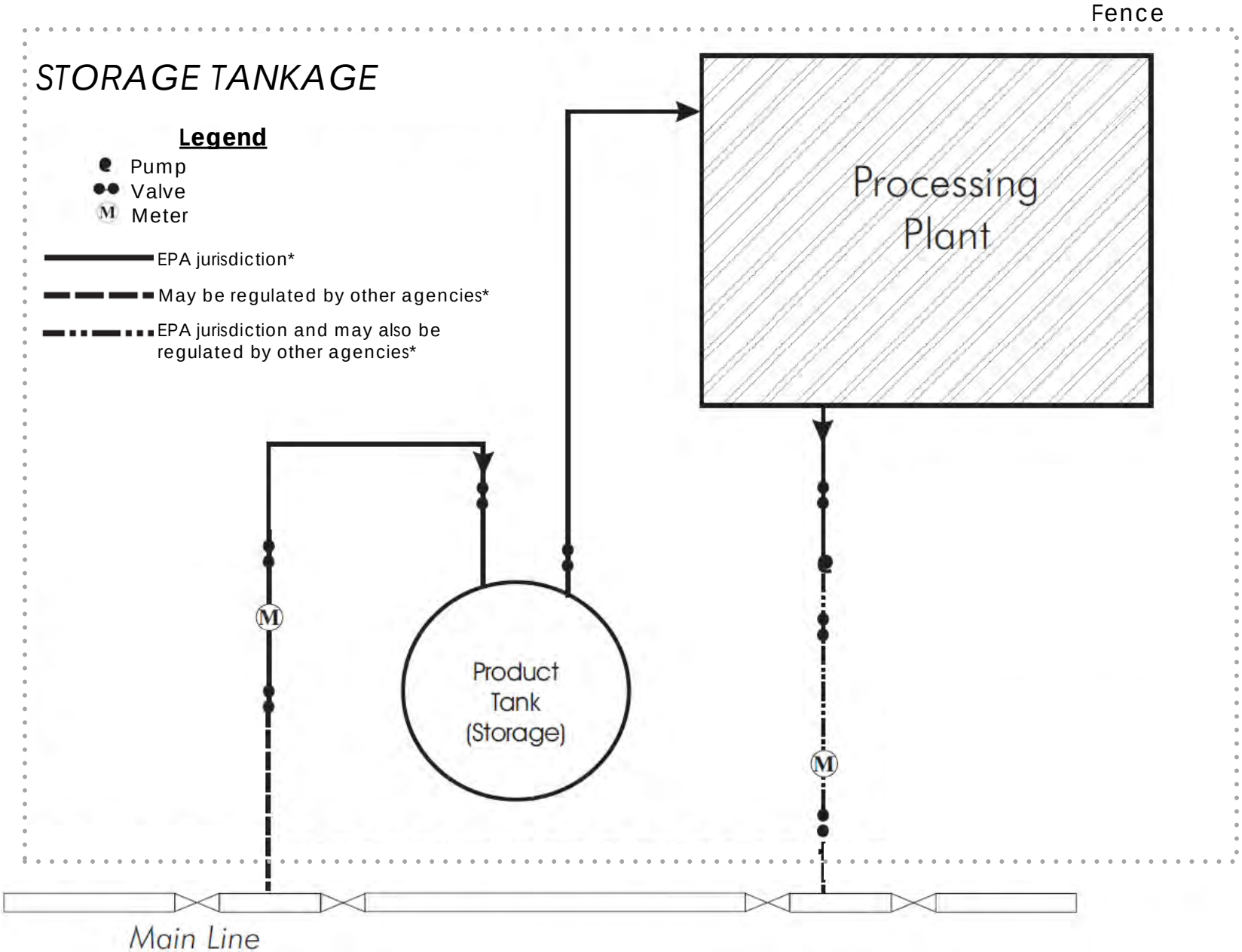


[1] Note that EPA does not have jurisdiction in this example.

STORAGE TANKAGE

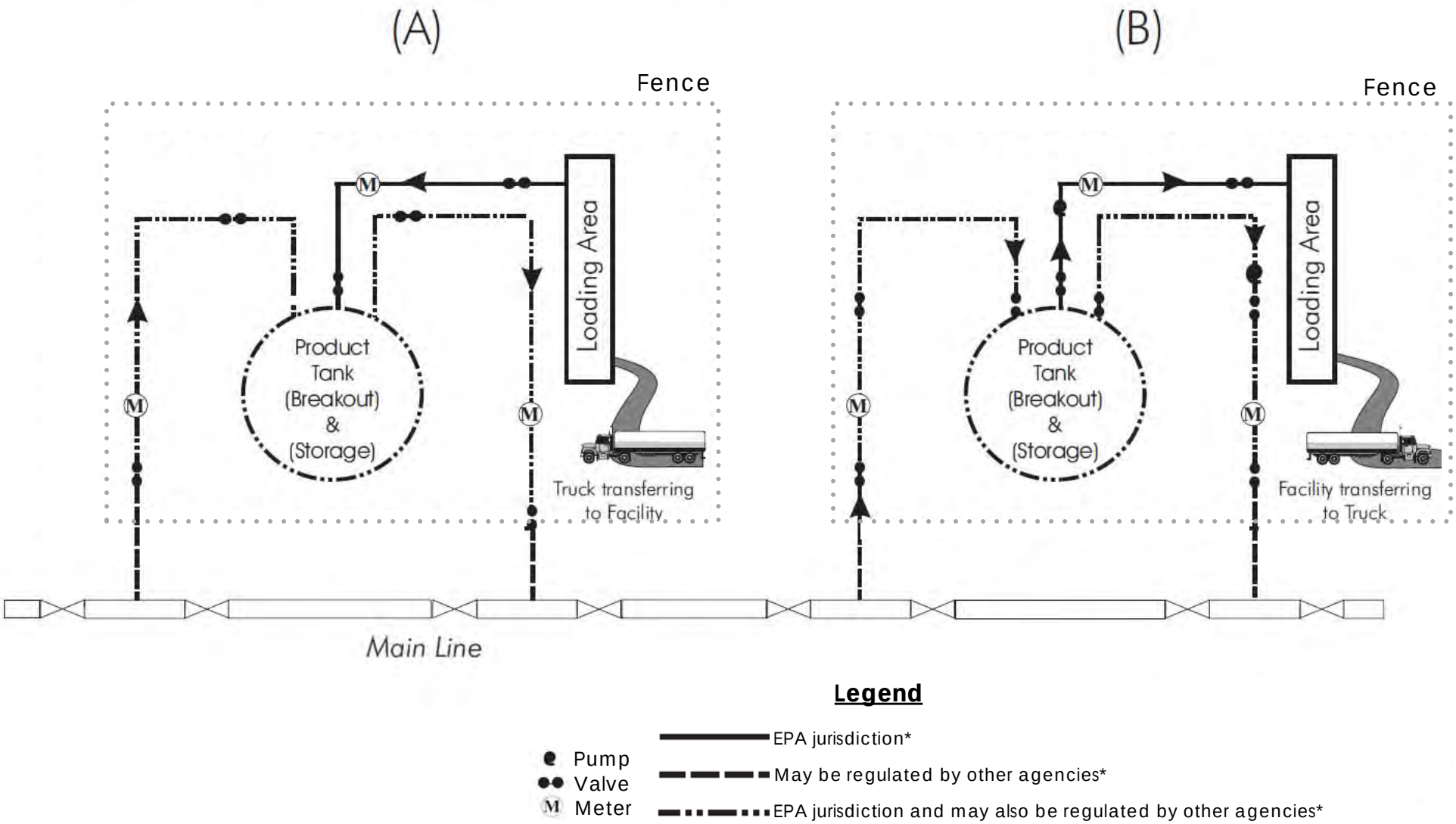


* This diagram does not identify the precise location where the change in jurisdiction may occur between EPA and any other agencies for the purpose of the Clean Water Act, Section 311(j) (33 USC 1321(j)). When the pipeline operator and the storage or breakout tank operator remain the same, the change in jurisdiction occurs at the first meter, valve, or isolation flange at or inside the facility property line. When the pipeline operator and the storage or breakout tank operator are not the same, the change in jurisdiction occurs at the change in operational responsibility or at the first meter, valve, or isolation flange at or inside the facility property line. In either of the above situations, the location of the property line should not solely be used to determine jurisdiction when operational activities (loading/offloading) extend beyond the property line.



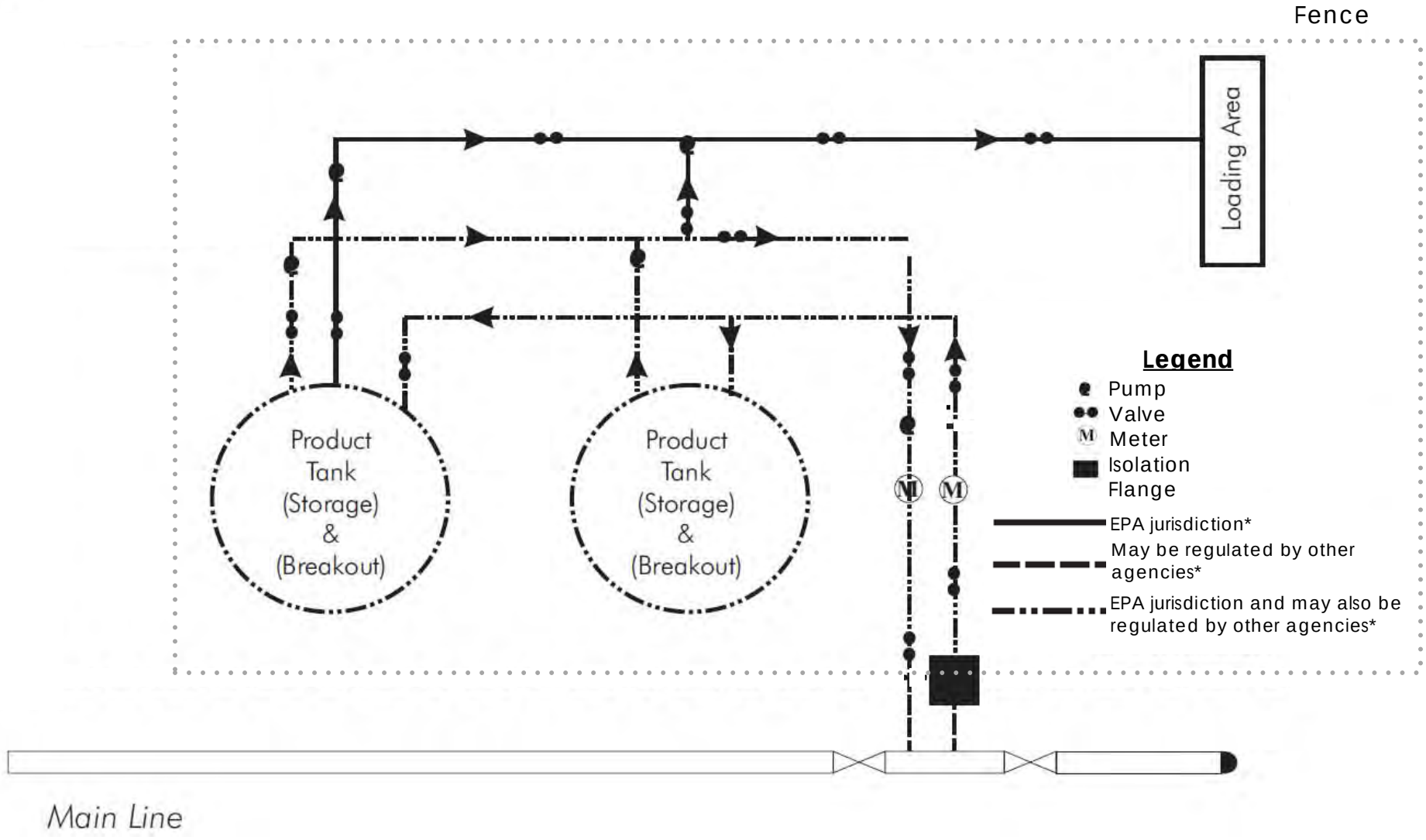
* This diagram does not identify the precise location where the change in jurisdiction may occur between EPA and any other agencies for the purpose of the Clean Water Act, Section 311(j) (33 USC 1321(j)). When the pipeline operator and the storage or breakout tank operator remain the same, the change in jurisdiction occurs at the first meter, valve, or isolation flange at or inside the facility property line. When the pipeline operator and the storage or breakout tank operator are not the same, the change in jurisdiction occurs at the change in operational responsibility or at the first meter, valve, or isolation flange at or inside the facility property line. In either of the above situations, the location of the property line should not solely be used to determine jurisdiction when operational activities (loading/offloading) extend beyond the property line.

BREAKOUT AND STORAGE TANKAGE – EPA and Other Agencies Jurisdiction



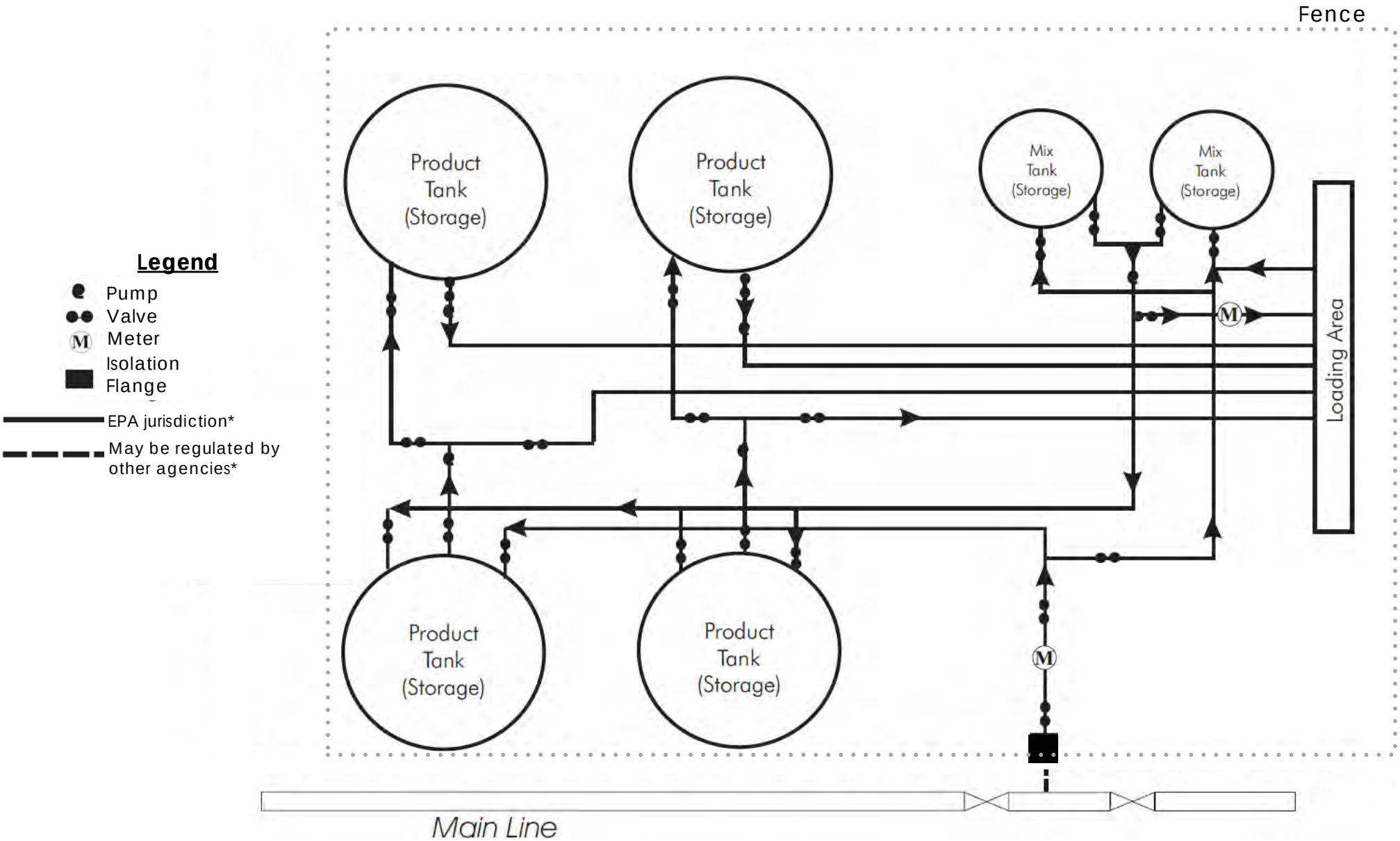
* This diagram does not identify the precise location where the change in jurisdiction may occur between EPA and any other agencies for the purpose of the Clean Water Act, Section 311(j) (33 USC 1321(j)). When the pipeline operator and the storage or breakout tank operator remain the same, the change in jurisdiction occurs at the first meter, valve, or isolation flange at or inside the facility property line. When the pipeline operator and the storage or breakout tank operator are not the same, the change in jurisdiction occurs at the change in operational responsibility or at the first meter, valve, or isolation flange at or inside the facility property line. In either of the above situations, the location of the property line should not solely be used to determine jurisdiction when operational activities (loading/offloading) extend beyond the property line.

BREAKOUT AND STORAGE TANKAGE – EPA and Other Agencies Jurisdiction



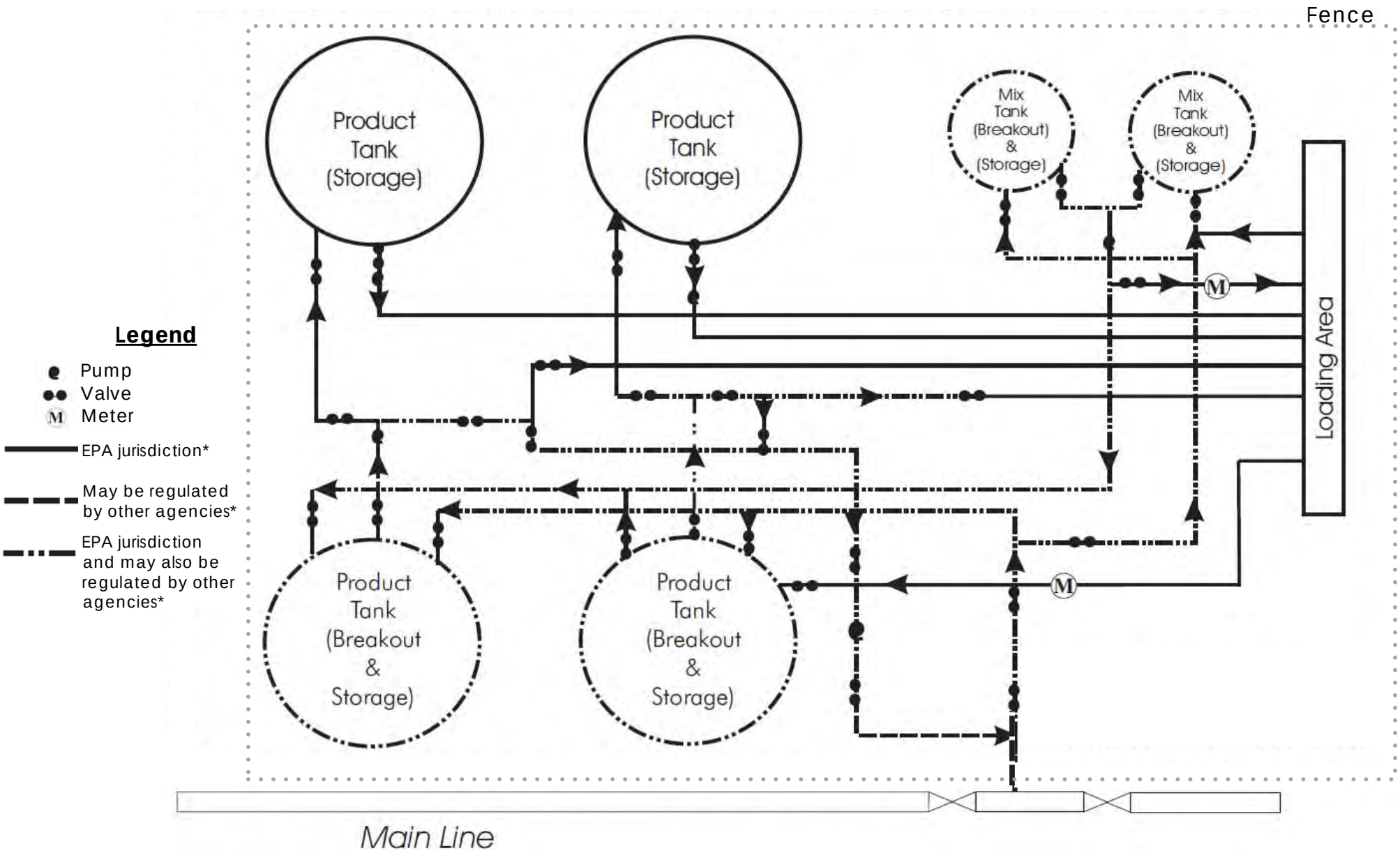
* This diagram does not identify the precise location where the change in jurisdiction may occur between EPA and any other agencies for the purpose of the Clean Water Act, Section 311(j) (33 USC 1321(j)). When the pipeline operator and the storage or breakout tank operator remain the same, the change in jurisdiction occurs at the first meter, valve, or isolation flange at or inside the facility property line. When the pipeline operator and the storage or breakout tank operator are not the same, the change in jurisdiction occurs at the change in operational responsibility or at the first meter, valve, or isolation flange at or inside the facility property line. In either of the above situations, the location of the property line should not solely be used to determine jurisdiction when operational activities (loading/offloading) extend beyond the property line.

STORAGE TANKAGE



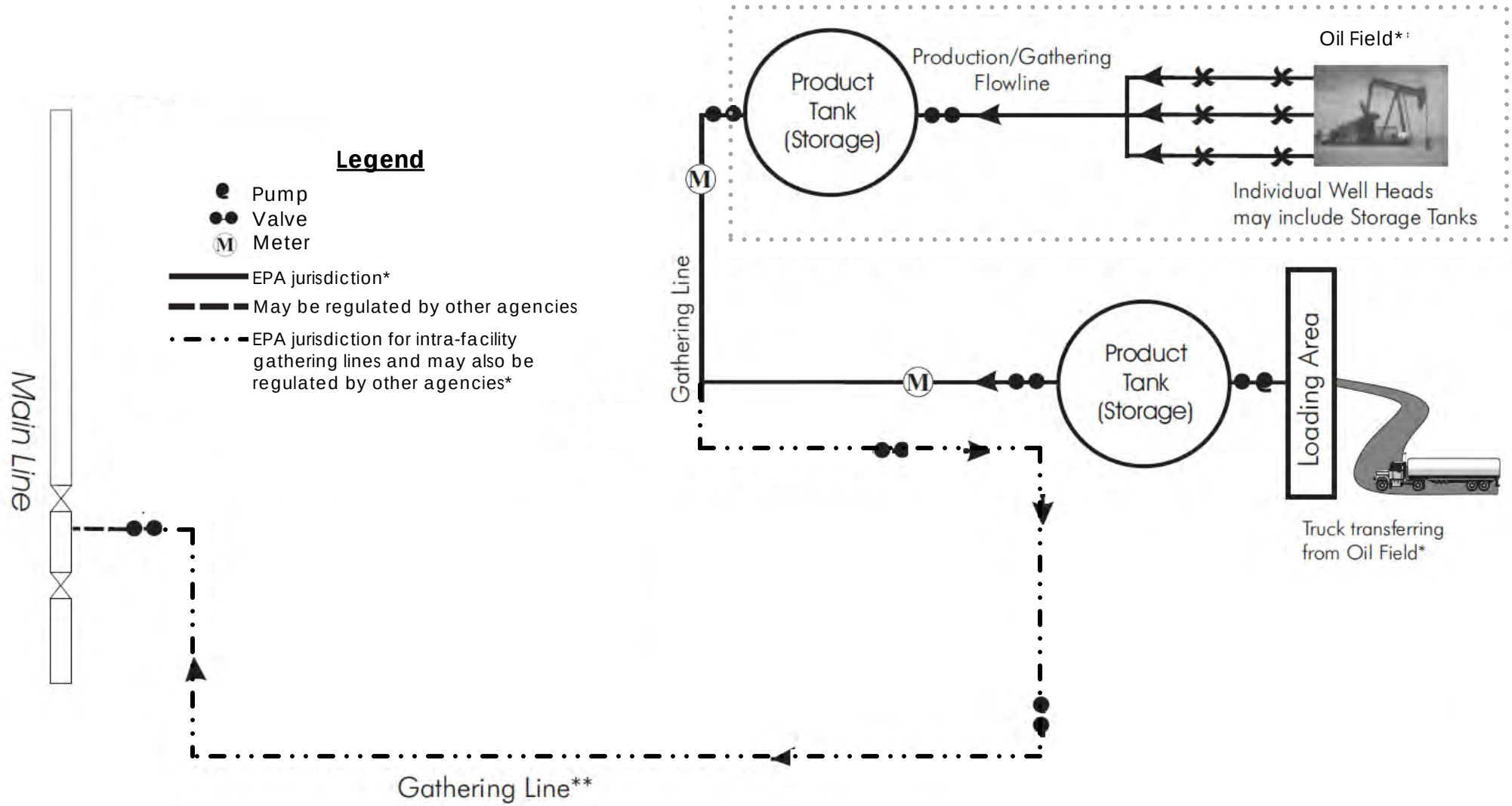
* This diagram does not identify the precise location where the change in jurisdiction may occur between EPA and any other agencies for the purpose of the Clean Water Act, Section 311(j) (33 USC 1321(j)). When the pipeline operator and the storage or breakout tank operator remain the same, the change in jurisdiction occurs at the first meter, valve, or isolation flange at or inside the facility property line. When the pipeline operator and the storage or breakout tank operator are not the same, the change in jurisdiction occurs at the change in operational responsibility or at the first meter, valve, or isolation flange at or inside the facility property line. In either of the above situations, the location of the property line should not solely be used to determine jurisdiction when operational activities (loading/offloading) extend beyond the property line.

BREAKOUT AND STORAGE TANKAGE – EPA and Other Agencies Jurisdiction



* This diagram does not identify the precise location where the change in jurisdiction may occur between EPA and any other agencies for the purpose of the Clean Water Act, Section 311(j) (33 USC 1321(j)). When the pipeline operator and the storage or breakout tank operator remain the same, the change in jurisdiction occurs at the first meter, valve, or isolation flange at or inside the facility property line. When the pipeline operator and the storage or breakout tank operator are not the same, the change in jurisdiction occurs at the change in operational responsibility or at the first meter, valve, or isolation flange at or inside the facility property line. In either of the above situations, the location of the property line should not solely be used to determine jurisdiction when operational activities (loading/offloading) extend beyond the property line.

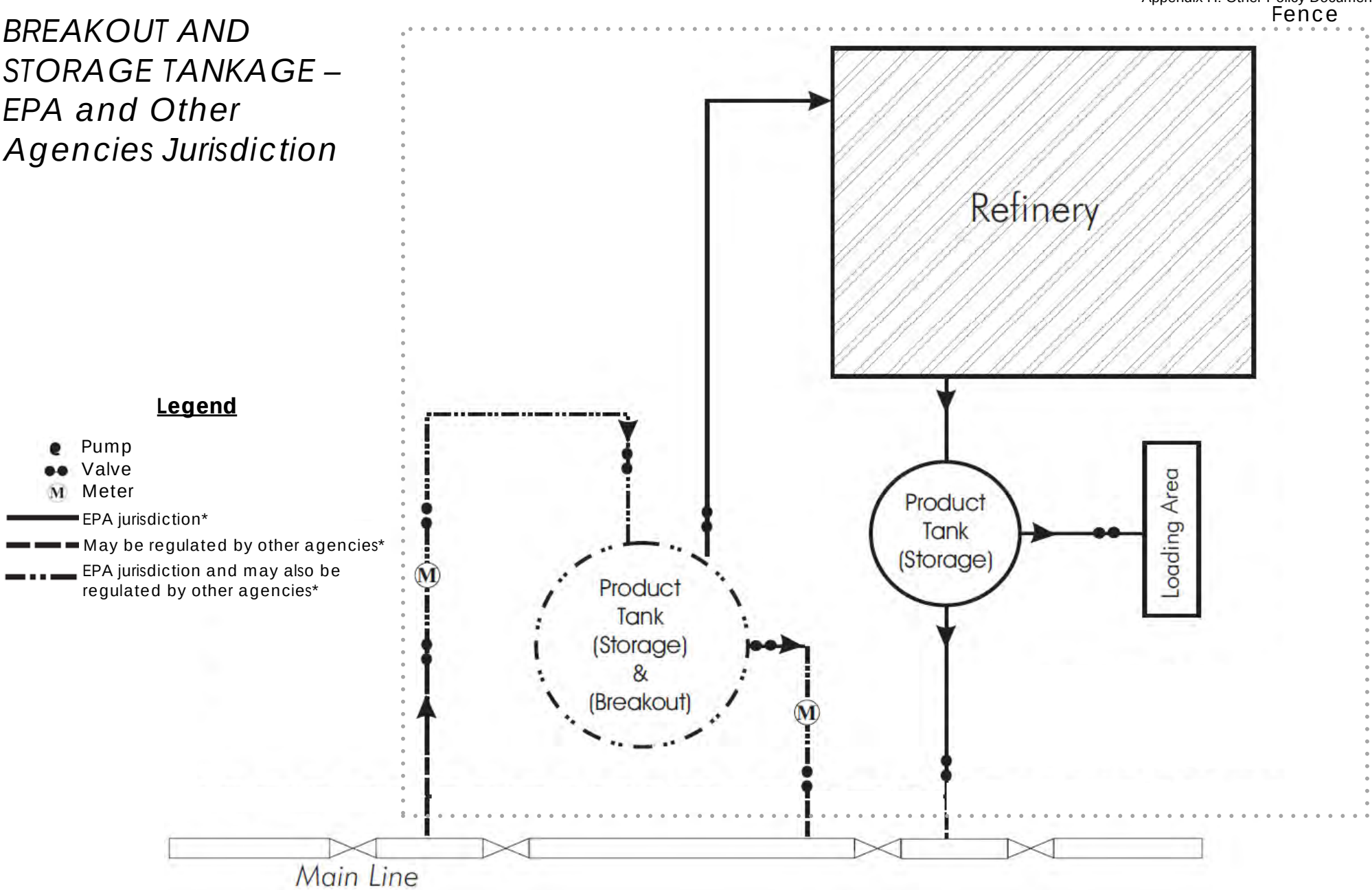
STORAGE TANKAGE ASSOCIATED WITH PRODUCTION/GATHERING LINES



*In 40 CFR 112.1, 112.7 and 112.9 EPA regulates onshore oil production facilities as defined in 112.2 including wells, flowlines, separation equipment, storage facilities, intra-facility gathering lines and auxiliary non-transportation-related equipment and facilities.

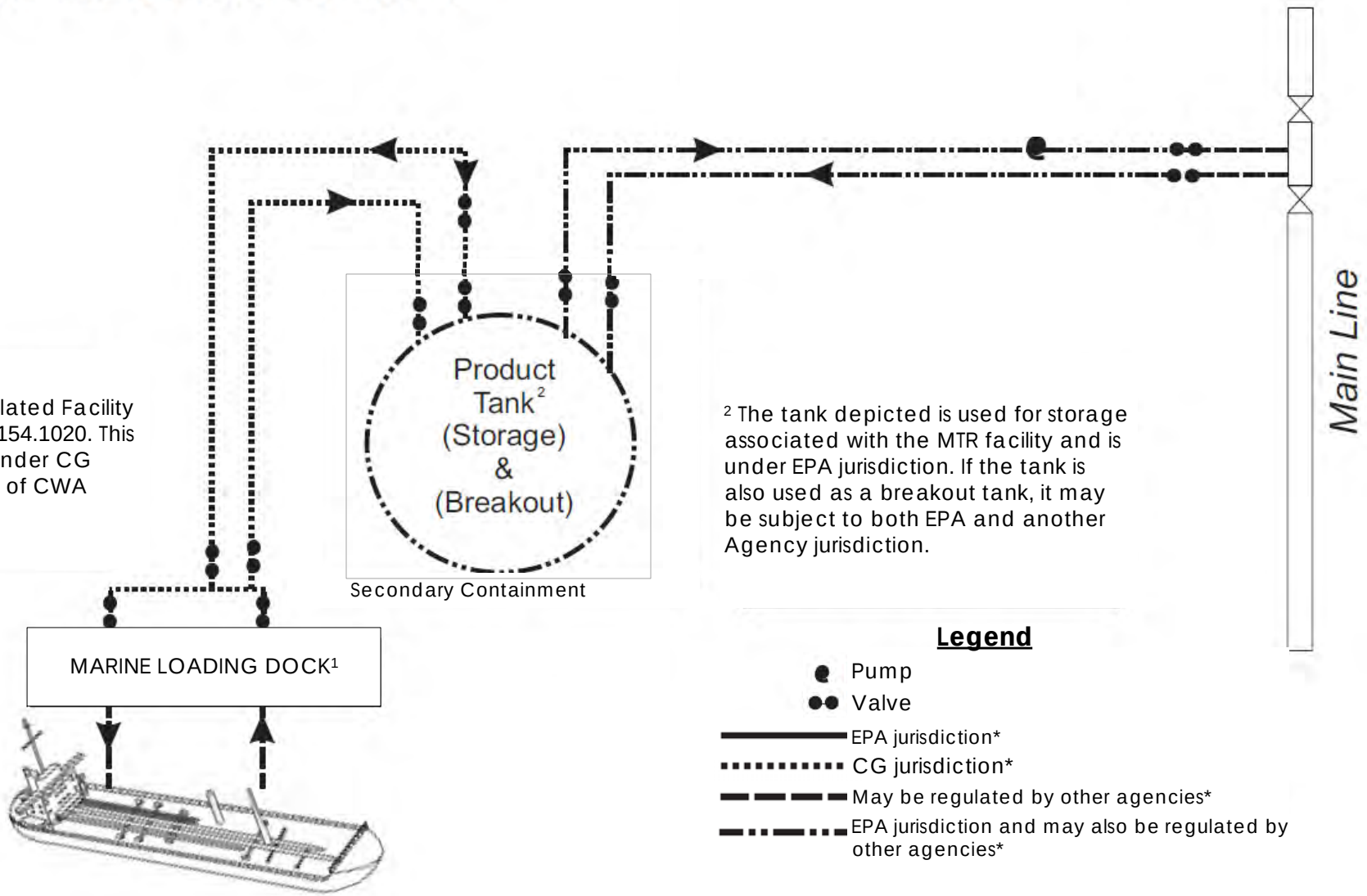
** EPA jurisdiction applies to all gathering lines located within an SPCC-regulated facility (i.e., intra-facility gathering lines). However, EPA exempts intra-facility gathering lines subject to the regulatory requirements of 49 CFR part 192 or 195, except that such lines must be identified and marked as exempt on the facility diagram.

BREAKOUT AND STORAGE TANKAGE – EPA and Other Agencies Jurisdiction



* This diagram does not identify the precise location where the change in jurisdiction may occur between EPA and any other agencies for the purpose of the Clean Water Act, Section 311(j) (33 USC 1321(j)). When the pipeline operator and the storage or breakout tank operator remain the same, the change in jurisdiction occurs at the first meter, valve, or isolation flange at or inside the facility property line. When the pipeline operator and the storage or breakout tank operator are not the same, the change in jurisdiction occurs at the change in operational responsibility or at the first meter, valve, or isolation flange at or inside the facility property line. In either of the above situations, the location of the property line should not solely be used to determine jurisdiction when operational activities (loading/offloading) extend beyond the property line.

EPA, COAST GUARD, AND OTHER AGENCIES JURISDICTION AT COMPLEX FACILITY



[1] Marine Transportation-Related Facility (MTR) is defined in 33 CFR 154.1020. This segment of a complex is under CG jurisdiction for the purpose of CWA Section 311 (j).

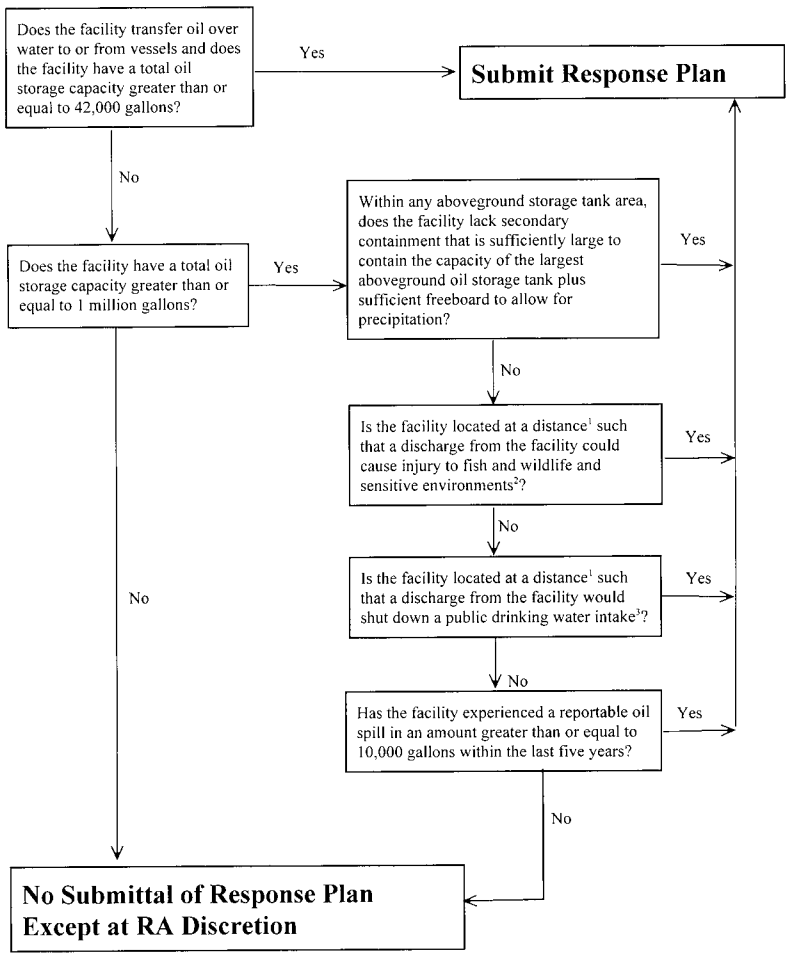
[2] The tank depicted is used for storage associated with the MTR facility and is under EPA jurisdiction. If the tank is also used as a breakout tank, it may be subject to both EPA and another Agency jurisdiction.

* This diagram does not identify the precise location where the change in jurisdiction may occur between EPA and any other agencies for the purpose of the Clean Water Act, Section 311(j) (33 USC 1321(j)). When the pipeline operator and the storage or breakout tank operator remain the same, the change in jurisdiction occurs at the first meter, valve, or isolation flange at or inside the facility property line. When the pipeline operator and the storage or breakout tank operator are not the same, the change in jurisdiction occurs at the change in operational responsibility or at the first meter, valve, or isolation flange at or inside the facility property line. In either of the above situations, the location of the property line should not solely be used to determine jurisdiction when operational activities (loading/offloading) extend beyond the property line.

ATTACHMENTS TO APPENDIX C

Attachment C-I

Flowchart of Criteria for Substantial Harm



[1] Calculated using the appropriate formula in Attachment C-III to this appendix or a comparable formula.

[2] For further description of fish and wildlife and sensitive environments, see Appendices I,II, and III to DOC/NOAA's "Guidance for Facility and vessel response Plans: Fish and Wildlife and Sensitive Environments" (59 FR 14713, March 29, 1994) and the applicable Area Contingency Plan.

[3] Public drinking water intakes are analogous to public water systems as described at CFR 143.2(c).

ATTACHMENT C-II—CERTIFICATION OF THE APPLICABILITY OF THE SUBSTANTIAL HARM CRITERIA

Facility Name: _____
Facility Address: _____

1. Does the facility transfer oil over water to or from vessels and does the facility have a total oil storage capacity greater than or equal to 42,000 gallons?

Yes _____ No _____

2. Does the facility have a total oil storage capacity greater than or equal to 1 million gallons and does the facility lack secondary containment that is sufficiently large to contain the capacity of the largest aboveground oil storage tank plus sufficient freeboard to allow for precipitation within any aboveground oil storage tank area?

Yes _____ No _____

3. Does the facility have a total oil storage capacity greater than or equal to 1 million gallons and is the facility located at a distance (as calculated using the appropriate formula in Attachment C–III to this appendix or a comparable formula[1]) such that a discharge from the facility could cause injury to fish and wildlife and sensitive environments? For further description of fish and wildlife and sensitive environments, see Appendices I, II, and III to DOC/NOAA's ''Guidance for Facility and Vessel Response Plans: Fish and Wildlife and Sensitive Environments'' (see appendix E to this part, section 13, for availability) and the applicable Area Contingency Plan.

Yes _____ No _____

4. Does the facility have a total oil storage capacity greater than or equal to 1 million gallons and is the facility located at a distance (as calculated using the appropriate formula in Attachment C-III to this appendix or a comparable formula[1]) such that a discharge from the facility would shut down a public drinking water intake[2]?

Yes _____ No _____

5. Does the facility have a total oil storage capacity greater than or equal to 1 million gallons and has the facility experienced a reportable oil discharge in an amount greater than or equal to 10,000 gallons within the last 5 years?

Yes _____ No _____

Certification

I certify under penalty of law that I have personally examined and am familiar with the information submitted in this document, and that based on my inquiry of those individuals responsible for obtaining this information, I believe that the submitted information is true, accurate, and complete.

_____
Signature

_____
Name (please type or print)

_____
Title

_____
Date

ATTACHMENT C-III—CALCULATION OF THE PLANNING DISTANCE

1.0 Introduction

1.1 The facility owner or operator must evaluate whether the facility is located at a distance such that a discharge from the facility could cause injury to fish and wildlife and sensitive environments or disrupt operations at a public drinking water intake. To quantify that distance, EPA considered oil transport mechanisms over land and on still, tidal influence, and moving navigable waters. EPA has determined that the primary concern for calculation of a planning distance is the transport of oil in navigable waters during adverse weather conditions. Therefore, two formulas have been developed to determine distances for planning purposes from the point of discharge at the facility to the potential site of impact on moving and still waters, respectively. The formula for oil transport on moving navigable water is based on the velocity of the water body and the time interval for arrival of response resources. The still water formula accounts for the spread of discharged oil over the surface of the water. The method to determine oil transport on tidal influence areas is based on the type of oil discharged and the distance down current during ebb tide and up current during flood tide to the point of maximum tidal influence.

1.2 EPA's formulas were designed to be simple to use. However, facility owners or operators may calculate planning distances using more sophisticated formulas, which take into account broader scientific or engineering principles, or local conditions. Such comparable formulas may result in different planning distances than EPA's formulas. In the event that an alternative formula that is comparable to one contained in this appendix is used to evaluate the criterion in 40 CFR 112.20(f)(1)(ii)(B) or (f)(1)(ii)(C), the owner or operator shall attach documentation to the response plan cover sheet contained in appendix F to this part that demonstrates the reliability and analytical soundness of the alternative formula and shall notify the Regional Administrator in

[1] If a comparable formula is used, documentation of the reliability and analytical soundness of the comparable formula must be attached to this form.

[2] For the purposes of 40 CFR part 112, public drinking water intakes are analogous to public water systems as described at 40 CFR 143.2(c).

Spill Prevention Control and Countermeasure (SPCC) Plan

Construct New Secondary Containment

EXAMPLE

This worksheet determines the possible dimensions for a rectangular or square dike or berm to meet the secondary containment requirement for aboveground bulk storage containers.

Steps:

A. Determining required dike or berm dimensions for largest single tank

1. Calculate the volume of the tank
2. Specify the containment wall height and one containment lateral dimension D1 to calculate lateral dimension D2
3. Calculate the volume of rain, V_{Rain} to be collected in the secondary containment with area A_{SC} for the specified rain event
4. Calculate the required secondary containment volume, V_{SCReq} to account for the additional volume of rain, V_{Rain}

B. Accounting for the displacements from other vertical cylindrical tanks to be located in dike or berm with the largest tank

C. Accounting for the displacements from other horizontal cylindrical tanks to be located In dike or berm with the largest tank

1. For SC_{Height} (ft), calculate the displacement from additional horizontal cylindrical tanks, Tank 2, 3, 4, etc., to be located with the largest tank in the dike or berm
2. Calculate the total displacement volume from the additional horizontal cylindrical tanks in the dike or berm

D. Accounting for the displacements from other rectangular tanks to be located in dike or berm with the largest tank

1. For SC_{Height} (ft), calculate the displacement from additional rectangular tanks, Tank 2, 3, 4, etc., to be located with the largest tank in the dike or berm
2. Calculate the total displacement volume from the additional rectangular tanks in the dike or berm

Disclaimer: Please note that these are simplified calculations for qualified facilities that assume: 1) the secondary containment is designed with a flat floor; 2) the wall height is equal for all four walls; and 3) the corners of the secondary containment system are 90 degrees. Additionally, the calculations do not include displacement for support structures or foundations. For Professional Engineer (PE) certified Plans, the PE may need to account for site-specific conditions associated with the secondary containment structure which may require modifications to these sample calculations to ensure good engineering practice.

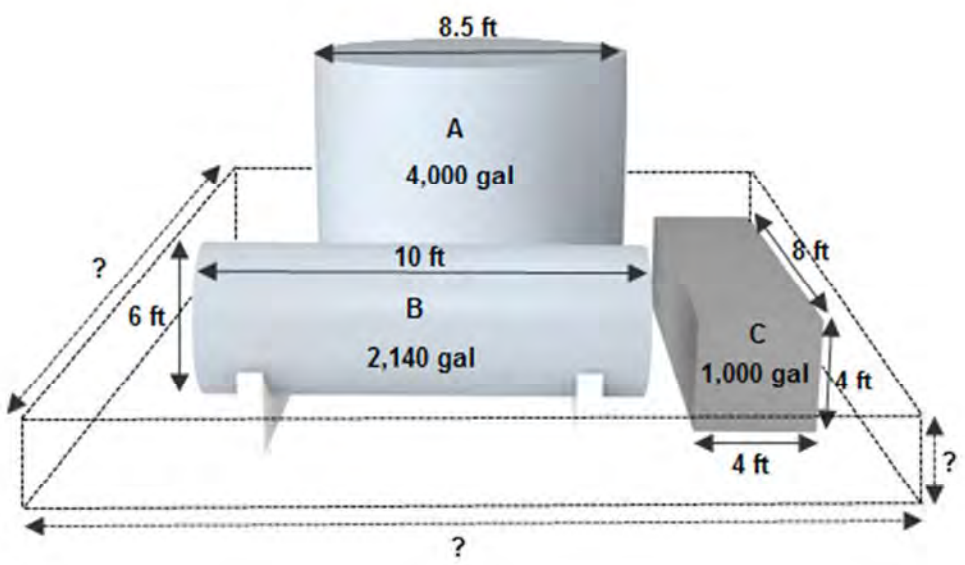
Spill Prevention Control and Countermeasure (SPCC) Plan

Construct New Secondary Containment

EXAMPLE

Information needed to use this worksheet:

- Tank shell capacity, diameter, length, and height
  See diagram for dimensions
- Secondary containment wall height
  Cannot exceed 6 feet per local fire code
- Rainfall amount
  Rainfall can collect in the secondary containment; the selected rain event for the location is 6 inches.
- Other considerations
  With a proposed containment wall height of 5 ft. and one lateral containment dimension of 10 ft., the height of Tank B below the top of the wall is 4 ft.



Spill Prevention Control and Countermeasure (SPCC) Plan

Construct New Secondary Containment

EXAMPLE

A. Determining required dike or berm dimensions for largest single tank

1. Calculate the volume of the tank

Largest Tank Shell Capacity (gal) = 4,000 (**a**)

Largest Tank Volume (ft^3) = 4,000 (a (gal)) ÷ 7.48 (gal/ft^3)

= 535 (ft^3) (**b**)

Note that state and local fire and safety codes may prescribe limits on the height of containment walls, minimum separation distances between tanks, and setback distances. For instance, Occupational Safety and Health Administration (OSHA) flammable and combustible liquids standards in 29 CFR 1910.106 prescribe separation distances between adjacent tanks. Such requirements may present constraints on the location, dimensions, and configuration of the secondary containment structure. The footprint of the tank or tanks and arrangement of the tanks when there is to be more than a single tank within secondary containment may also present constraints on the containment dimensions.

2. Specify the containment wall height and one containment lateral dimension D1 to calculate lateral dimension D2

Height of Containment Wall, SC_{Height} (ft) = 5 (c) ft

Height of Containment Wall, SC_{Height} (in) = 5 (c (ft)) x 12 (in/ft)

= 60 (**d**) in

D1 (ft) = 10 (e) ft

D2 (ft) = 535 (b (ft^3)) ÷ 5 (c (ft)) ÷ 10 (e (ft)) = 10.7 (**f**) ft

***b** is the volume of the largest tank calculated in Step 1.*

Spill Prevention Control and Countermeasure (SPCC) Plan

Construct New Secondary Containment

EXAMPLE

3. Calculate the volume of rain, V_{Rain} to be collected in the secondary containment with area A_{SC} for the specified rain event

Selected Rainfall Event:

24— Hr 25— Yr

Rainfall (in) = 6 in
g

***f** is lateral dimension D2 calculated in Step 2.*

A_{SC} *(ft²) =* 10 (e (ft)) x 10.7 (f (ft)) = 107 (**h**) ft^2

V_{Rain} *(ft³) =* 6 (g (in)) ÷ 12 (in/ft) x 107 (h (ft^2))

= 53.5 ft^3
i

4. Calculate the required secondary containment volume, V_{SCReq} to account for the additional volume of rain, V_{Rain}

***b** is the volume of the largest tank calculated in Step 1.*

V_{SCReq} *(ft³) =* 535 (b (ft^3)) + 53.5 (i (ft^3)) = 588.5 (**j**) ft^3

Vary the secondary containment height and lateral dimensions, or footprint, in Step 2 to meet any space or dimension constraints or requirements and the required containment volume, V_{SCReq} by using V_{SCReq} in place of the volume of the largest shell capacity tank, **b** in Step 2.

2. (Repeated with a required containment capacity of 588.5 ft³) Specify the containment wall height and one containment lateral dimension D1 to calculate lateral dimension D2

Height of Containment Wall, SC_{Height} (ft) = 5 ft
c

Height of Containment Wall, SC_{Height} (in) = 5 (c (ft)) x 12 (in/ft)

= 60 in
d

D1 (ft) = 10 ft
e

***b** is the volume of the largest tank calculated in Step 1.*
588.5 ft³ was used for this calculation.

D2 (ft) = 588.5 (b (ft^3)) ÷ 5 (c (ft)) ÷ 10 (e (ft)) = 11.8 (**f**) ft

For the same containment wall height and lateral dimension D1, D2 has to increase to 11.8 ft for the secondary containment capacity to be adequate.

Spill Prevention Control and Countermeasure (SPCC) Plan

Construct New Secondary Containment

EXAMPLE

IF APPLICABLE: When other tanks or containers are also to be located within the secondary containment along with the largest tank, calculate the displacement volumes from these other tanks or containers using Parts B, C and D as applicable. Add the total displacement volume from the other tanks or containers to the volume of rain, V_{Rain} and the largest tank volume, **b**, in Step 1, to obtain a net secondary containment volume, V_{NetSC}:

V_{NetSC} (ft^3) = 588.5 (j (ft^3)) + 331 (Total Displacement Volume (ft^3)) = 919.5 (**k**) ft^3

j is the required secondary containment volume calculated in Step 4.

Note: In this example, the total displacement of 331 ft^3 result from the displacement of 203 ft^3 from the horizontal cylindrical tank calculated in Part C and 128 ft^3 from the rectangular tank calculated in Part D.

Vary the secondary containment height and lateral dimensions, or footprint, in Step 2 to meet any space or dimension constraints or requirements and the net required containment volume, V_{NetSC} by using V_{NetSC} in place of the volume of the largest shell capacity tank, **b**.

2. (*Repeated with a required containment capacity of 919.5 ft^3*) *Specify the containment wall height and one containment lateral dimension D1 to calculate lateral dimension D2*

Height of Containment Wall, SC_{Height} (ft) = 6 (c) ft

Height of Containment Wall, SC_{Height} (in) = 6 (c (ft)) x 12 (in/ft)

= 72 (**d**) in

D1 (ft) = 10 (e) ft

b is the volume of the largest tank calculated in Step 1.
919.5 ft^3 was used for this calculation.

D2 (ft) = 919.5 (b (ft^3)) ÷ 6 (c (ft)) ÷ 10 (e (ft)) = 15.3 (**f**) ft

Increasing the containment wall height from 5 ft. to the limit of 6 ft. with the same D1 lateral dimension of 10 ft. increases D2 to 15.3 ft. for the secondary containment capacity to be adequate and account for the other tank displacements. Changing the containment wall height will require reviewing and recalculating displacement volumes if necessary as the tank heights below the top of the wall may change. Also, as the containment area or footprint increase, recalculations of the corresponding increase in the volume of rain, V_{Rain}, that can collect in the containment using Step 3 and reassessment of containment capacity will be necessary.

B. <u>Accounting for the displacements from other vertical cylindrical tanks to be located in dike or berm with the largest tank</u>

The single vertical cylindrical tank is the largest shell capacity tank; there are no other vertical cylindrical tanks within the same secondary containment.

Spill Prevention Control and Countermeasure (SPCC) Plan

Construct New Secondary Containment

EXAMPLE

C. Accounting for the displacements from other horizontal cylindrical tanks to be located in dike or berm with the largest tank

1. For SC_{Height} (ft), calculate the displacement from additional horizontal cylindrical tanks, Tank 2, 3, 4, etc., to be located with the largest tank in the dike or berm

The easiest way to determine the displacement volume in a horizontal cylindrical tank is to use the tank manufacturer's liquid height to gallons conversion chart for the tank in Method 1 calculation. If this information is not available, use Method 2 calculation to obtain the displacement volumes.

METHOD 1

Height of Tank B Below Containment Wall (in) = [ ] in

$V_{Tank\ B}$ *Displacement (gal) From Tank Conversion Chart* = [ ] gal
q

$V_{Tank\ B}$ *Displacement (ft^3)* = [ ] x 0.1337 = [ ] ft^3
q (gal) ft^3/gal **r**

Repeat to calculate the displacement of each additional horizontal cylindrical tank located with the largest tank in the dike or berm.

Total Displacement Volume (ft^3) = [ ] + [ ] + [ ] + ...
r (ft^3) r1 (ft^3) r2 (ft^3)

= [ ] ft^3
s

METHOD 2

Height of Tank B Below Containment Wall (in) = [48] in
t

Tank B Diameter (in) = [6] x 12 = [72] in
Diameter (ft) in/ft **u**

Height to Diameter Ratio for Tank B = [48] ÷ [72] = [0.67]
t (in) u (in) **v**

Tank B Volume Fraction for Height to Diameter Ratio (Table) = [0.71]
w

If the tank shell capacity in gallons is known:

Tank Volume $V_{Tank\ B}$ (ft^3) = [2,140] x 0.1337 = [286] ft^3
Shell Capacity (gal) ft^3/gal **x**

Spill Prevention Control and Countermeasure (SPCC) Plan

Construct New Secondary Containment

EXAMPLE

METHOD 2 (CONT)

Or, if the tank shell capacity in gallons is not known:

Tank B radius (ft) = [ ] ÷ 2 = [ ] ft
Diameter (ft)

$V_{Tank\ B}$ *(ft³)* = 3.14 x [( )^2] x [ ] = [ ] ft³
Radius (ft) — Tank Length (ft) — **y**

Displacement, $V_{Tank\ B}$ *(ft³)* = [286] x [0.71] = [203] ft³
x or y (ft³) — w — **z**

Repeat to calculate the displacement volume of each additional horizontal cylindrical tank to be located with the largest tank in the dike or berm.

2. Calculate the total displacement volume from the additional horizontal cylindrical tanks in the dike or berm

Total Displacement Volume (ft³) = [203] + [0] + [0] + ...
z (ft³) — z1 (ft³) — z2 (ft³)

***z** is the displacement volume calculated in Step 1, Method 2 of C.*

= [203] ft³
aa

Spill Prevention Control and Countermeasure (SPCC) Plan

Construct New Secondary Containment

EXAMPLE

D. <u>Accounting for the displacements from other rectangular tanks to be located in dike or berm with the largest tank</u>

1. Calculate the total displacement volume from the additional horizontal cylindrical tanks in the dike or berm

Height of Tank C Below Containment Wall (ft) = 4 ft
ab

Length of Tank C (ft) = 8
ac

Width of Tank 2 (ft) = 4
ad

Displacement Area, $DA_{Tank\ C}$ (ft^2) = 8 (ac (ft)) x 4 (ad (ft)) = 32 (ft^2) **ae**

Displacement Volume, $DV_{Tank\ C}$ (ft^3) = 32 (ae (ft^2)) x 4 (ab (ft))

= 128 (ft^3)
af

Repeat Step 1 to calculate the displacement area and volume of each additional rectangular tank to be located with the largest tank in the dike or berm.

2. Calculate the total displacement volume from the additional horizontal cylindrical tanks in the dike or berm

Total Displacement Volume (ft^3) = 203 (af (ft^3)) + 0 (af1 (ft^3)) + 0 (af2 (ft^3)) + ...

***af** is the displacement volume calculated in Step 1 of D.*

= 203 (ft^3)
ag

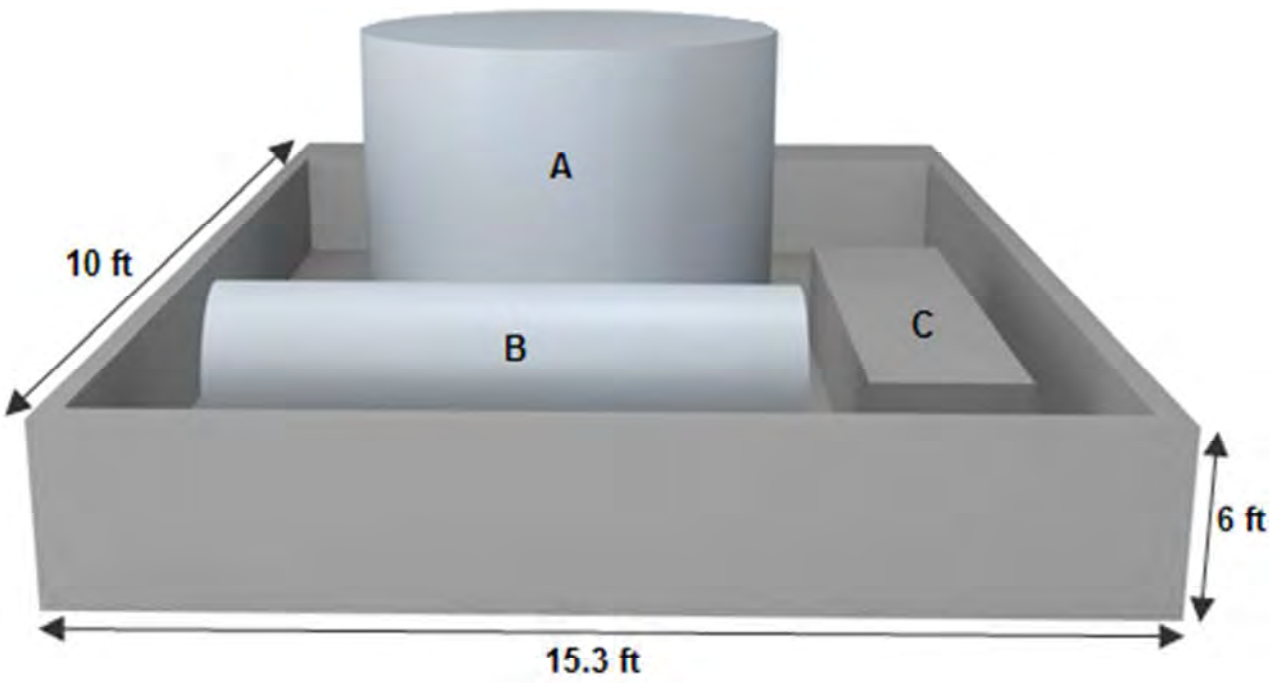
Spill Prevention Control and Countermeasure (SPCC) Plan

Construct New Secondary Containment

EXAMPLE

Calculated acceptable dike dimensions

The preceding calculations produced the following dimensions shown in the diagram for one possible dike configuration that would meet the required secondary capacity to conform to the SPCC regulation and the local fire code's 6 ft dike height limit.



Spill Prevention Control and Countermeasure (SPCC) Plan

Multiple Horizontal Cylindrical Tanks Inside a Rectangular or Square Dike or Berm

EXAMPLE

This worksheet calculates the secondary containment volume of a rectangular or square dike or berm for three horizontal cylindrical tanks. In this example, displacements of the tanks except for the largest tank in the berm must be accounted for when determining the required secondary containment volume.

Steps:

1. Determine the volume of the secondary containment, V_{SC}

2a. Determine the volume of the tank when the tank shell capacity is unknown, V_{Tank}

2b. Determine the volume of the tank when shell capacity is known, V_{Tank}

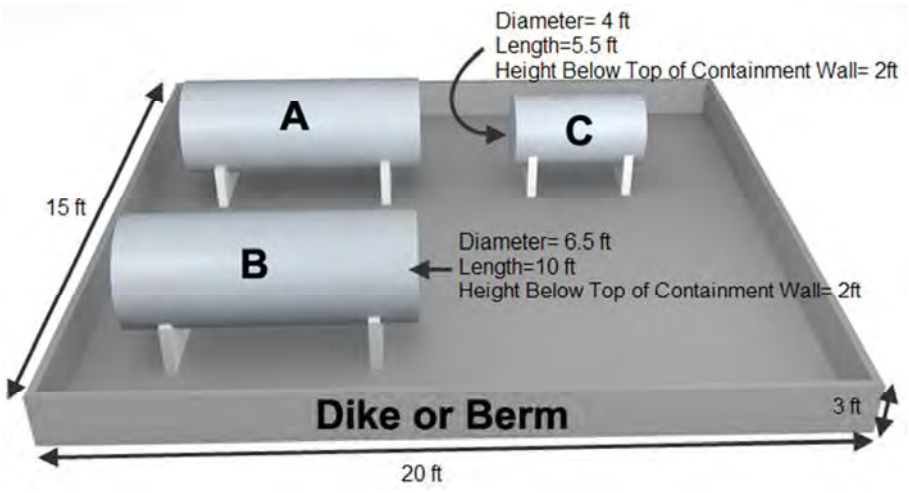
3. Determine the unavailable (displacement) areas and volumes in the containment due to other tanks within the containment and the net containment volume remaining for the largest tank

4. Determine the percentage of the net secondary containment volume, V_{SCNet} to the largest tank volume, V_{Tank}

5. Determine whether the secondary containment can contain the entire tank shell capacity with additional capacity to contain rain.

Information needed to use this worksheet:

- Tank shell capacity
  Tanks A (off-road diesel) and B (on-road diesel) each has a shell capacity of 2,500 gallons while Tank C (gasoline) has a shell capacity of 500 gallons. Diameters and lengths of the tanks are as shown.
- Secondary containment length, width, and height
  See diagram for dimensions.
- Height of each tank below top of containment wall (except largest tank)
  See diagram for dimensions
- Rainfall amount
  Rainfall can collect in the secondary containment; the selected rain event for the location is 7 inches.



Largest Tank Shell Capacity (gal) = 2,500
a

Disclaimer: Please note that these are simplified calculations for qualified facilities that assume: 1) the secondary containment is designed with a flat floor; 2) the wall height is equal for all four walls; and 3) the corners of the secondary containment system are 90 degrees. Additionally, the calculations do not include displacement for support structures or foundations. For Professional Engineer (PE) certified Plans, the PE may need to account for site-specific conditions associated with the secondary containment structure which may require modifications to these sample calculations to ensure good engineering practice.

Spill Prevention Control and Countermeasure (SPCC) Plan

Multiple Horizontal Cylindrical Tanks Inside a Rectangular or Square Dike or Berm

EXAMPLE

1. Determine the volume of the secondary containment, V_{SC}

Secondary Containment Area, A_{SC} = 20 (Length (ft)) x 15 (Width (ft))

= 300 (ft^2) **b**

V_{SC} (ft^3) = 300 (b (ft^2)) x 3 (Height (ft)) = 900 (ft^3) **c**

2a. Determine the volume of the tank when the tank shell capacity is unknown, V_{Tank}

Tank radius (ft) = 6.5 (Diameter (ft)) ÷ 2 = 3.25 ft

V_{Tank} (ft^3) = 3.14 x $(3.25)^2$ (Radius^2 $(ft)^2$) x 10 (Tank Length (ft)) = 332 (ft^3) **d**

2b. Determine the volume of the tank when shell capacity is known, V_{Tank}

***a** is the tank shell capacity from page 1.*

V_{Tank} (ft^3) = 2,500 (a (gal)) x 0.1337 (ft^3/gal) = 334 (ft^3) **e**

3. Determine the unavailable (displacement) areas and volumes in the containment due to other tanks within the containment and the net containment volume remaining for the largest tank

The easiest way to determine the displacement volume in a horizontal cylindrical tank is to use the tank manufacturer's liquid height to gallons conversion chart for the tank in Method 1 calculation. If this information is not available, use Method 2 calculation to obtain the displacement volumes.

Spill Prevention Control and Countermeasure (SPCC) Plan

Multiple Horizontal Cylindrical Tanks Inside a Rectangular or Square Dike or Berm

EXAMPLE

METHOD 1

Height of Tank B Below Containment Wall (in) = [ ] in

$V_{Tank\ B}$ *Displacement (gal) From Tank Conversion Chart* = [ ] gal
f

$V_{Tank\ B}$ *Displacement* (ft^3) = [ ] x 0.1337 = [ ] ft^3
f (gal) ft^3/gal **g**

Calculate the displacement of each additional horizontal cylindrical tank within the same secondary containment:

Total Displacement Volume (ft^3) = [ ] + [ ] + [ ] + ...
g (ft^3) g1 (ft^3) g2 (ft^3)

= [ ] ft^3
h

METHOD 2

Height of Tank B Below Containment Wall (in) = 24 in
i

Tank B Diameter (in) = 6.5 x 12 = 78 in
Diameter (ft) in/ft **j**

Height to Diameter Ratio for Tank B = 24 ÷ 78 = 0.31
i (in) j (in) **k**

Tank B Volume Fraction for Height to Diameter Ratio (Table) = 0.263
l

<u>If the tank shell capacity in gallons is known:</u>

Tank Volume $V_{Tank\ B}$ (ft^3) = 2,500 x 0.1337 = 334 ft^3
Shell Capacity (gal) ft^3/gal **m**

Spill Prevention Control and Countermeasure (SPCC) Plan

Multiple Horizontal Cylindrical Tanks Inside a Rectangular or Square Dike or Berm

EXAMPLE

METHOD 2 (CONT)

Or, if the tank shell capacity in gallons is not known:

Tank B radius (ft) = [ ] ÷ 2 = [ ] ft
Diameter (ft)

$V_{Tank\ B}$ (ft^3) = 3.14 x [( )^2] x [ ] = [ ] ft^3
Radius (ft) — Tank Length (ft) — **n**

Displacement, $V_{Tank\ B}$ (ft^3) = [334] x [0.263] = [88] ft^3
m (ft^3) — l — **o**

***m** is the tank volume (Tank B).*
***l** is the Tank B volume fraction for H/D ratio (table).*

Calculate the displacement of each additional horizontal cylindrical tank within the same secondary containment:

Height of Tank C Below Containment Wall (in) = [24] in
i

Tank C Diameter (in) = [4] x 12 = [48] in
Diameter (ft) — in/ft — **j**

Height to Diameter Ratio for Tank C = [24] ÷ [48] = [0.50]
i (in) — j (in) — **k**

Tank C Volume Fraction for Height to Diameter Ratio (Table) = [0.5]
l

Tank Volume $V_{Tank\ C}$ (ft^3) = [500] x 0.1337 = [67] ft^3
Shell Capacity (gal) — ft^3/gal — **m**

Displacement, $V_{Tank\ C}$ (ft^3) = [67] x [0.5] = [34] ft^3
m (ft^3) — l — **o1**

Total Displacement Volume (ft^3) = [88] + [34]
o (ft^3) — o1 (ft^3)

= [122] ft^3
p

Net Secondary Containment Volume:

Net Containment Volume, V_{SCNet} (ft^3) = [900] — [122] = [778] ft^3
c (ft^3) — p (Method 2) (ft^3) — **q**

***c** is the secondary contianment volume.*

Spill Prevention Control and Countermeasure (SPCC) Plan

Multiple Horizontal Cylindrical Tanks Inside a Rectangular or Square Dike or Berm

EXAMPLE

4. Determine the percentage of the net secondary containment volume, V_{SCNet} to the largest tank volume, V_{Tank}[1] (to determine whether the volume of the containment is sufficient to contain the largest tank's entire shell capacity).

V_{SCNet}/V_{Tank} =	778	÷	334	=	2.33
	q (ft^3)		e (ft^3)		**r**
% =	2.33	x	100	=	233
	r				**s**

q *is the net secondary contianment volume.*
e *is the tank volume calculated in Step 2b of this worksheet.*

The percentage, **s**, is 233% which is greater than 100%. The secondary containment volume is sufficient to contain the shell capacity of the largest tank after accounting for the displacements. However, we must also account for rain that can collect in the dike or berm. See step 5.

5. Determine whether the secondary containment can contain the entire tank shell capacity with additional capacity to contain rain.

If rain can collect in a dike or berm, the SPCC rule requires that secondary containment for bulk storage containers have additional capacity to contain rainfall or freeboard. The rule does not specify a method to determine the additional capacity required to contain rain or the size of the rain event for designing secondary containment. However, industry practice often considers a rule of thumb of 110% of the tank capacity to account for rainfall. A dike with a 110% capacity of the tank may be acceptable depending on, the shell size of the tank, local precipitation patterns and frequency of containment inspections. In a different geographic area, a dike or berm designed to hold 110% for the same size tank may not have enough additional containment capacity to account for a typical rain event in that area. The 110% standard may also not suffice for larger storm events. If you want to determine a conservative capacity for a rain event, you may want to consider a 24-hour 25-year storm event. It is the responsibility of the owner or operator[2] to determine the additional containment capacity necessary to contain rain. A typical rain event may exceed the amount determined by using a 110% "rule of thumb" so it is important to consider the amount of a typical rain event when designing or assessing your secondary containment capacity.

Rainfall data may be available from various sources such as local water authorities, local airports, and the National Oceanic and Atmospheric Administration (NOAA).

[1] Steps 4 and 5 in the worksheet determines whether the net volume of the secondary containment is sufficient to contain the largest tank's entire shell capacity and rainfall (freeboard for precipitation) as required by the SPCC rule. Step 4 primarily determines whether the net volume of the secondary containment is sufficient to contain the entire shell capacity of the largest tank. Step 5 is necessary to determine whether the secondary containment can also contain the expected volume of rainfall (both the volume of rain that falls into the containment plus the rain from the tank storage site).

[2] The SPCC rule does not require you to show the secondary containment calculations in your Plan. However, you should maintain documentation of secondary containment calculations to demonstrate compliance to an EPA inspector.

Spill Prevention Control and Countermeasure (SPCC) Plan

Multiple Horizontal Cylindrical Tanks Inside a Rectangular or Square Dike or Berm

EXAMPLE

Selected Rainfall Event:

24— Hr 25— Yr

Rainfall (in) = 7 in
t

Rainfall (ft) = 7 ÷ 12
t (in) in/ft

0.6 ft
u

Volume of Rain to be Contained, V_{Rain} (ft^3) = 0.6 x 300 = 180 ft^3
u (ft) b (ft^2) **v**

Total Containment Capacity Required (ft^3) = 180 + 334
v (ft^3) e (ft^3)

514 ft^3
w

The net secondary containment volume after accounting for displacements in **q** is 778 ft^3, which is equal to or greater than the required containment capacity in **w**, which is 514 ft^3. Therefore, the secondary containment is sufficient to contain the shell capacity of the largest tank and has sufficient additional capacity to contain a typical rainfall amount.

The percentage of the net secondary containment volume to the largest tank shell capacity volume is 233% (**s** in Step 4). This percentage, which is greater than 100%, indicates that additional secondary containment capacity is available to contain rain as the containment is exposed to rain. Subtracting the largest tank shell capacity volume V_{Tank} of 334 ft^3 (**e** in Step 4) from the net containment volume V_{SCNet} of 778 ft^3 (**q** in Step 4) yields 444 ft^3 of additional containment capacity for rain. V_{Rain}, the volume of rain falling into the secondary containment in a 24-hour 25-year rainfall event that produces 7 inches of rain, is 180 ft^3 (**v** in Step 5). V_{Rain} is less than the 444 ft^3 of additional containment capacity by 264 ft^3; consequently, the additional secondary containment capacity is sufficient to also contain the rain from the selected rainfall event. As concluded at the end of Step 5 in this example, the net secondary containment volume is sufficient to contain the shell capacity of the largest tank and the selected typical rainfall amount.

Spill Prevention Control and Countermeasure (SPCC) Plan

Multiple Horizontal Cylindrical Tanks Inside a Rectangular or Square Dike or Berm

EXAMPLE

Table of H/D Ratios and Corresponding Percent of Tank Volume

"H" is the tank height below the top of the containment wall. "D" is the tank diameter.

H/D Ratio	Percent of Tank Vol	H/D ratio	Percent of Tank Vol	H/D ratio	Percent of Tank Vol
0	0	0.34	0.301	0.68	0.724
0.01	0.002	0.35	0.312	0.69	0.737
0.02	0.003	0.36	0.323	0.70	0.747
0.03	0.009	0.37	0.337	0.71	0.760
0.04	0.013	0.38	0.348	0.72	0.770
0.05	0.020	0.39	0.362	0.73	0.783
0.06	0.025	0.40	0.374	0.74	0.792
0.07	0.030	0.41	0.385	0.75	0.805
0.08	0.038	0.42	0.400	0.76	0.816
0.09	0.045	0.43	0.411	0.77	0.825
0.10	0.053	0.44	0.423	0.78	0.837
0.11	0.058	0.45	0.435	0.79	0.848
0.12	0.068	0.46	0.450	0.80	0.858
0.13	0.075	0.47	0.461	0.81	0.869
0.14	0.085	0.48	0.473	0.82	0.879
0.15	0.094	0.49	0.488	0.83	0.888
0.16	0.102	0.50	0.500	0.84	0.898
0.17	0.112	0.51	0.512	0.85	0.906
0.18	0.121	0.52	0.527	0.86	0.915
0.19	0.131	0.53	0.539	0.87	0.925
0.20	0.142	0.54	0.550	0.88	0.932
0.21	0.152	0.55	0.565	0.89	0.942
0.22	0.163	0.56	0.577	0.90	0.947
0.23	0.175	0.57	0.589	0.91	0.955
0.24	0.184	0.58	0.600	0.92	0.962
0.25	0.195	0.59	0.615	0.93	0.970
0.26	0.208	0.60	0.626	0.94	0.975
0.27	0.217	0.61	0.638	0.95	0.980
0.28	0.230	0.62	0.652	0.96	0.987
0.29	0.240	0.63	0.663	0.97	0.991
0.30	0.253	0.64	0.677	0.98	0.997
0.31	0.263	0.65	0.688	0.99	0.998
0.32	0.276	0.66	0.699	1.00	1.000
0.33	0.287	0.67	0.713		

Spill Prevention Control and Countermeasure (SPCC) Plan

Rectangular or Square Remote Impoundment Structure

EXAMPLE

This worksheet calculates the containment volume of a rectangular or square remote impoundment[1] structure providing secondary containment for an aboveground tank storage facility.

Steps:

1. Determine the volume of the secondary containment impoundment, V_{SC}

2a. Determine the volume of the largest tank when shell capacity is unknown, V_{Tank}

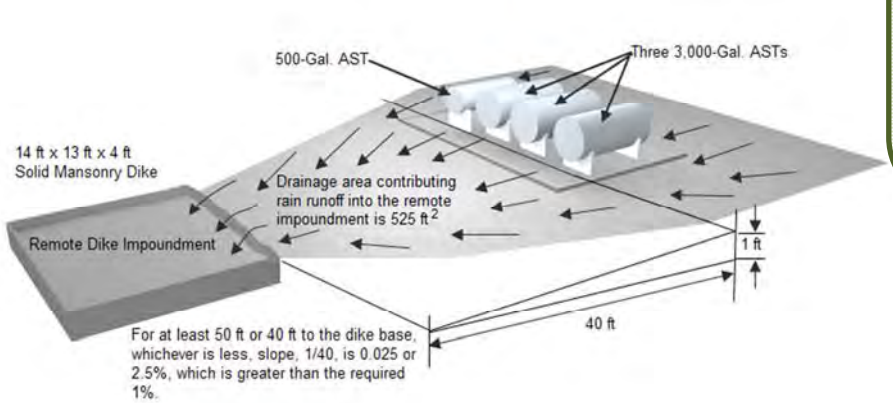
2b. Determine the volume of the largest tank when shell capacity is known, V_{Tank}

3. Determine the percentage of the secondary containment volume, V_{SC} to the largest tank volume, V_{Tank}

4. Determine whether the secondary containment impoundment can contain the entire tank shell capacity of the largest tank with additional capacity to contain rain.

Information needed to use this worksheet:

- **Tank shell capacity**
  See diagram for capacities.
- **Remote impoundment length, width, and height**
  See diagram for dimensions.
- **Rainfall amount**
  Rain can fall into the impoundment and the area draining into the impoundment. The selected rain event for the location is 7 inches. See the diagram to obtain the surface drainage area in square feet.



Largest Tank Shell Capacity (gal) = 3,000

a

Disclaimer: Please note that these are simplified calculations for qualified facilities that assume: 1) the secondary containment is designed with a flat floor; 2) the wall height is equal for all four walls; and 3) the corners of the secondary containment system are 90 degrees. Additionally, the calculations do not include displacement for support structures or foundations. For Professional Engineer (PE) certified Plans, the PE may need to account for site-specific conditions associated with the secondary containment structure which may require modifications to these sample calculations to ensure good engineering practice.

[1] Remote impounding is an acceptable secondary containment method under NFPA 30 because the code primarily focuses on fire safety and emphasizes the importance of moving leaked or spilled flammable liquids away from the tank by adequate draining. A remote impoundment must be able to contain the contents of the largest tank. However, when this is not possible, partial impounding can be used in combination with diking to meet the largest-tank criterion.

For tank fields contained by diking, NFPA 30 requires that a slope of not less than one percent away from the tank shall be provided for at least 50 feet or to the dike base, whichever is less. This ensures that small spills will not accumulate against the wall of the tank. Also, if remote impounding is used, the drainage path to the impoundment should be designed so that if the drainage path is ignited, the flames will not pose serious risk to tanks or adjoining property.

Spill Prevention Control and Countermeasure (SPCC) Plan

Rectangular or Square Remote Impoundment Structure

EXAMPLE

1. Determine the volume of the secondary containment impoundment, V_{SC}

Impoundment Containment Area, A_{SC} = 14 (Length (ft)) x 13 (Width (ft))

= 182 (**b**) ft^2

V_{SC} (ft^3) = 182 (b (ft^2)) x 4 (Height (ft)) = 728 (**c**) ft^3

2a. Determine the volume of the largest tank when the shell capacity is unknown, V_{Tank}

Tank radius (ft) = _____ (Diameter (ft)) ÷ 2 = _____ ft

V_{Tank} (ft^3) = 3.14 x ( )^2 (Radius^2 $(ft)^2$) x _____ (Tank Height (ft)) = _____ (**d**) ft^3

2b. Determine the volume of the largest tank when shell capacity is known, V_{Tank}

***a** is the tank shell capacity from page 1.*

V_{Tank} (ft^3) = 3,000 (a (gal)) x 0.1337 (ft^3/gal) = 401 (**e**) ft^3

Spill Prevention Control and Countermeasure (SPCC) Plan

Rectangular or Square Remote Impoundment Structure

EXAMPLE

3. Determine the percentage of the secondary containment volume, V_{SC} to the largest tank volume, V_{Tank}[2](to determine whether the volume of the containment is sufficient to contain the largest tank's entire shell capacity).

__c__ is the secondary contianment volume.
__d__ / __e__ is the tank volume calculated in Step 2 of this worksheet.

V_{SC}/V_{Tank} =	728	÷	401	=	1.82
	c (ft^3)		d or e (ft^3)		**f**
% =	1.82	x	100	=	182
	f				**g**

Percentage, **g**, is 182%, which is greater than 100%.The capacity of the impoundment containment is sufficient to contain the shell capacity of the largest tank. However, we must also account for rain that can collect in the impoundment. See Step 4.

4. Determine whether the secondary containment impoundment can contain the entire tank shell capacity with additional capacity to contain rain.

If rain can collect in a remote impoundment structure, the SPCC rule requires that secondary containment for bulk storage containers have additional capacity to contain rainfall or freeboard. The rule does not specify a method to determine the additional capacity required to contain rain or the size of the rain event for designing secondary containment. However, industry practice often considers a rule of thumb of 110% of the tank capacity to account for rainfall. Secondary containment with a 110% capacity of the tank may be acceptable depending on, the shell size of the tank, local precipitation patterns and frequency of containment inspections. In a different geographic area, secondary containment designed to hold 110% for the same size tank may not have enough additional containment capacity to account for a typical rain event in that area. The 110% standard may also not suffice for larger storm events. If you want to determine a conservative capacity for a rain event, you may want to consider a 24-hour 25-year storm event. It is the responsibility of the owner or operator[3] to determine the additional containment capacity necessary to contain rain. A typical rain event may exceed the amount determined by using a 110% "rule of thumb" so it is important to consider the amount of a typical rain event when designing or assessing your secondary containment capacity.

Rainfall data may be available from various sources such as local water authorities, local airports, and the National Oceanic and Atmospheric Administration (NOAA).

[2] Steps 3 and 4 in the worksheet determines whether the volume of the impoundment containment is sufficient to contain the largest tank's entire shell capacity and rainfall (freeboard for precipitation) as required by the SPCC rule. Step 3 primarily determines whether the volume of the impoundment containment is sufficient to contain the entire shell capacity of the largest tank. Step 4 is necessary to determine whether the impoundment containment can also contain the expected volume of rainfall (both the volume of rain that falls into the impoundment plus the rain from the drainage area contributing runoff into the impoundment).

[3] The SPCC rule does not require you to show the secondary containment calculations in your Plan. However, you should maintain documentation of secondary containment calculations to demonstrate compliance to an EPA inspector.

Spill Prevention Control and Countermeasure (SPCC) Plan

Rectangular or Square Remote Impoundment Structure

EXAMPLE

Selected Rainfall Event:

Rainfall (in) = 7 in
h

Rainfall (ft) = 7 ÷ 12
h (in) in/ft

= 0.6 ft
i

Volume of rain, $V_{RainImpound}$, that can fall directly into the impoundment:

$V_{RainImpound}$ *(ft^3)* = 0.6 x 182 = 109 ft^3
i (ft) b (ft^2) **j**

***b** is the area of secondary containment calculated in Step 1 of this worksheet*

Volume of rain contributed from the Impoundment Drainage Area, $V_{DrainageArea}$, to the remote impoundment: (The drainage surface area, $A_{DrainageArea}$, contributing rain runoff into the remote dike impoundment in ft^2 is required to determine $V_{DrainageArea}$. This information can be obtained from the as-built plans for the design and construction of the impoundment).

Area of Drainage, $A_{DrainageArea}$ (ft^2) = 525 ft^2
k

$V_{DrainageArea}$ *(ft^3)* = 0.6 x 525 = 315 ft^3
i (ft) k (ft^2) **l**

Total Volume of Rain Collected in Impoundment, $V_{TotalRainImpound}$:

$V_{TotalRainImpound}$ *(ft^3)* = 109 + 315 = 424 ft^3
j (ft^3) l (ft^3) **m**

Total Containment Capacity Required (ft^3) = 424 + 401
m (ft^3) e (ft^3)

***e** is the tank volume calculated in Step 2 of this worksheet*

= 825 ft^3
n

The volume of the impoundment containment in **c** is 728 ft^3, which is less than the required containment capacity in **n** (825 ft^3). Therefore, the impoundment containment is not sufficient to contain the shell capacity of the largest tank and the typical rainfall amount.

The percentage of the impoundment containment volume to the largest tank shell capacity volume is 182% (**g** in Step 3). This percentage, which is greater than 100%, indicates that additional impoundment containment capacity is available to contain rain as the containment is exposed to rain. Subtracting the largest tank shell capacity volume V_{Tank} of 401 ft^3 (**d** or **e** in Step 3) from the impoundment containment volume V_{SC} of 728 ft^3 (**c** in Step 3) yields 327 ft^3 of additional containment capacity for rain. $V_{TotalRainImpound}$, the total volume of rain collected in the impoundment containment in a 24-hour 25-year rainfall event that produces 7 inches of rain, is 424 ft^3 (**m** in Step 4). $V_{TotalRainImpound}$ is more than the 327 ft^3 of additional containment capacity by 97 ft^3; consequently, the additional impoundment containment capacity is **not sufficient** to also contain the rain from the selected rainfall event.

As concluded at the end of Step 4 in this example, the impoundment containment is **not sufficient** to contain the shell capacity of the largest tank and the selected typical rainfall amount.

Spill Prevention Control and Countermeasure (SPCC) Plan

Single Vertical Cylindrical Tank Inside a Rectangular or Square Dike or Berm

EXAMPLE

This worksheet calculates the secondary containment volume of a rectangular or square dike or berm for a single vertical cylindrical tank. In this example, there are no other objects or structures within the dike or berm that will displace the volume of the secondary containment.

Steps:

1. Determine the volume of the secondary containment, V_{SC}

2a. Determine the volume of the tank when the tank shell capacity is unknown, V_{Tank}

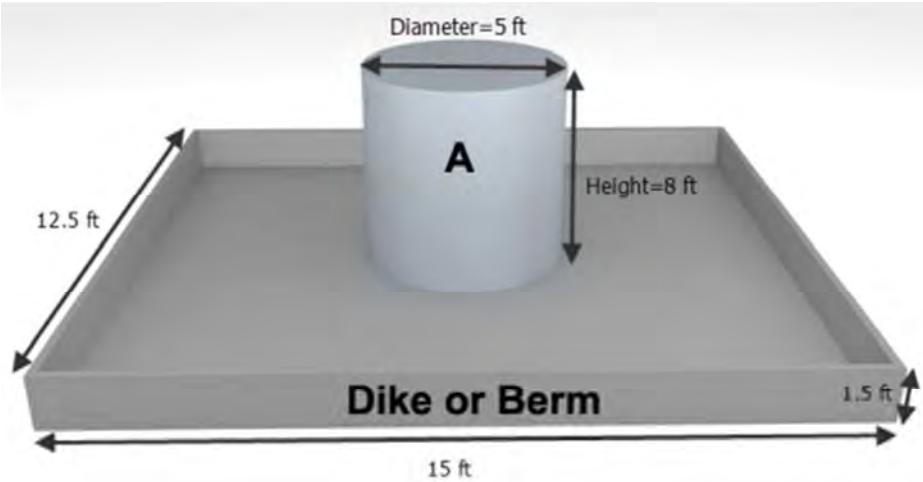
2b. Determine the volume of the tank when shell capacity is known, V_{Tank}

3. Determine the percentage of the secondary containment volume, V_{SC} to the tank volume, V_{Tank}

4. Determine whether the secondary containment can contain the entire tank shell capacity with additional capacity to contain rain.

Information needed to use this worksheet:

- Tank shell capacity
  In this example the tank is 1,200 gallons, the tank diameter is 5 ft, and tank height is 8 ft.
- Secondary containment length, width, and height
  See diagram for dimensions.
- Rainfall amount
  Rainfall can collect in the secondary containment; the selected rain event for the location is 7 inches.



Tank A Shell Capacity (gal) = 1,200

a

Disclaimer: Please note that these are simplified calculations for qualified facilities that assume: 1) the secondary containment is designed with a flat floor; 2) the wall height is equal for all four walls; and 3) the corners of the secondary containment system are 90 degrees. Additionally, the calculations do not include displacement for support structures or foundations. For Professional Engineer (PE) certified Plans, the PE may need to account for site-specific conditions associated with the secondary containment structure which may require modifications to these sample calculations to ensure good engineering practice.

Spill Prevention Control and Countermeasure (SPCC) Plan

Single Vertical Cylindrical Tank Inside a Rectangular or Square Dike or Berm

EXAMPLE

1. Determine the volume of the secondary containment, V_{SC}

Secondary Containment Area, A_{SC} = 15 (Length (ft)) x 12.5 (Width (ft))

= 187.5 (ft^2) **b**

V_{SC} (ft^3) = 187.5 (b (ft^2)) x 1.5 (Height (ft)) = 281.3 (ft^3) **c**

2a. Determine the volume of the tank when the tank shell capacity is unknown, V_{Tank}

(In this example we know the tank capacity so we skip this step.)

Tank radius (ft) = _____ (Diameter (ft)) ÷ 2 = _____ ft

V_{Tank} (ft^3) = 3.14 x ( )^2 (Radius^2 (ft)^2) x _____ (Tank Height (ft)) = _____ (ft^3) **d**

2b. Determine the volume of the tank when shell capacity is known, V_{Tank}

***a** is the tank shell capacity from page 1.*

V_{Tank} (ft^3) = 1,200 (a (gal)) x 0.1337 (ft^3/gal) = 160.4 (ft^3) **e**

Spill Prevention Control and Countermeasure (SPCC) Plan

Single Vertical Cylindrical Tank Inside a Rectangular or Square Dike or Berm

EXAMPLE

3. Determine the percentage of the secondary containment volume, V_{SC} to the tank volume, V_{Tank}[1]
(to determine whether the volume of the containment is sufficient to contain the tank's entire shell capacity).

__c__ is the secondary contianment volume.
__d__ / __e__ is the tank volume calculated in Step 2 of this worksheet.

V_{SC}/V_{Tank} = 281.3 (c, ft^3) ÷ 160.4 (d or e, ft^3) = 1.75 (**f**)

% = 1.75 (f) x 100 = 175 (**g**)

Percentage, **g**, is 175% which is greater than 100%. The capacity of the secondary containment is sufficient to contain the shell capacity of the tank. However, we must also account for rain that can collect in the dike or berm. See Step 4.

4. Determine whether the secondary containment can contain the entire tank shell capacity with additional capacity to contain rain.

If rain can collect in a dike or berm, the SPCC rule requires that secondary containment for bulk storage containers have additional capacity to contain rainfall or freeboard. The rule does not specify a method to determine the additional capacity required to contain rain or the size of the rain event for designing secondary containment. However, industry practice often considers a rule of thumb of 110% of the tank capacity to account for rainfall. A dike with a 110% capacity of the tank may be acceptable depending on, the shell size of the tank, local precipitation patterns and frequency of containment inspections. In a different geographic area, a dike or berm designed to hold 110% for the same size tank may not have enough additional containment capacity to account for a typical rain event in that area. The 110% standard may also not suffice for larger storm events. If you want to determine a conservative capacity for a rain event, you may want to consider a 24-hour 25-year storm event. It is the responsibility of the owner or operator[2] to determine the additional containment capacity necessary to contain rain. A typical rain event may exceed the amount determined by using a 110% "rule of thumb" so it is important to consider the amount of a typical rain event when designing or assessing your secondary containment capacity.

Rainfall data may be available from various sources such as local water authorities, local airports, and the National Oceanic and Atmospheric Administration (NOAA).

[1] Steps 3 and 4 in the worksheet determines whether the volume of the secondary containment is sufficient to contain the tank's entire shell capacity and rainfall (freeboard for precipitation) as required by the SPCC rule. Step 3 primarily determines whether the volume of the secondary containment is sufficient to contain the entire shell capacity of the tank. Step 4 is necessary to determine whether the secondary containment can also contain the expected volume of rainfall (both the volume of rain that falls into the containment plus the rain from the tank storage site).

[2] The SPCC rule does not require you to show the secondary containment calculations in your Plan. However, you should maintain documentation of secondary containment calculations to demonstrate compliance to an EPA inspector.

Spill Prevention Control and Countermeasure (SPCC) Plan

Single Vertical Cylindrical Tank Inside a Rectangular or Square Dike or Berm

EXAMPLE

Selected Rainfall Event:

24— Hr 25— Yr

Rainfall (in) = 7.0 in
h

Rainfall (ft) = 7.0 ÷ 12
h (in) in/ft

0.6 ft
i

Volume of Rain to be Contained, V_{Rain} (ft^3) = 0.6 x 187.5 = 112.5 ft^3
i (ft) b (ft^2) **j**

b *is the area of secondary containment calculated in Step 1 of this worksheet*

Total Containment Capacity Required (ft^3) = 112.5 + 160.4
j (ft^3) d or e (ft^3)

d */* ***e*** *is the tank volume calculated in Step 2 of this worksheet*

272.9 ft^3
k

The volume of the secondary containment in **c** is 281.3 ft^3, which is greater than the required containment capacity in **k** (272.9 ft^3). Therefore, the secondary containment is sufficient to contain the shell capacity of the tank and has sufficient additional capacity to contain a typical rainfall amount.

The percentage of the secondary containment volume to the tank shell capacity volume is 175% (**g** in Step 3). This percentage, which is greater than 100%, indicates that additional secondary containment capacity is available to contain rain as the containment is exposed to rain. Subtracting the tank shell capacity volume V_{Tank} of 160.4 ft^3 (**d** or **e** in Step 3) from the containment volume V_{SC} of 281.3 ft^3 (**c** in Step 3) yields 120.9 ft^3 of additional containment capacity for rain. V_{Rain}, the volume of rain falling into the secondary containment in a 24-hour 25-year rainfall event that produces 7 inches of rain, is 112.5 ft^3 (**j** in Step 4). V_{Rain} is less than the 120.9 ft^3 of additional containment capacity by 8.4 ft^3; consequently, the additional secondary containment capacity is sufficient to also contain the rain from the selected rainfall event. As concluded at the end of Step 4 in this example, the secondary containment is sufficient to contain the shell capacity of the tank and the selected typical rainfall amount.

Spill Prevention Control and Countermeasure (SPCC) Plan

Construct New Secondary Containment

WORKSHEET

This worksheet can be used to determine the possible dimensions for a rectangular or square dike or berm to meet the secondary containment requirement for aboveground bulk storage containers.

Information needed to use this worksheet:

- Tank shell capacity, diameter, length, and height
- Secondary containment length, width, and/or height limitations
- If rain can collect in secondary containment; the amount of rain, inches or feet, for the location

Steps:

A. Determining required dike or berm dimensions for largest single tank

1. Calculate the volume of the tank
2. Specify the containment wall height and one containment lateral dimension D1 to calculate lateral dimension D2
3. Calculate the volume of rain, V_{Rain}, to be collected in the secondary containment with area A_{SC} for the specified rain event
4. Calculate the required secondary containment volume, V_{SCReq}, to account for the additional volume of rain, V_{Rain}

B. Accounting for the displacements from other vertical cylindrical tanks to be located in dike or berm with the largest tank

1. For SC_{Height} (ft), calculate the displacement from additional vertical cylindrical tanks, Tank 2, 3, 4, etc., to be located with the largest tank in the dike or berm
2. Calculate the total displacement volume from the additional vertical cylindrical tanks in the dike or berm

C. Accounting for the displacements from other horizontal cylindrical tanks to be located In dike or berm with the largest tank

1. For SC_{Height} (ft), calculate the displacement from additional horizontal cylindrical tanks, Tank 2, 3, 4, etc., to be located with the largest tank in the dike or berm
2. Calculate the total displacement volume from the additional horizontal cylindrical tanks in the dike or berm

D. Accounting for the displacements from other rectangular tanks to be located in dike or berm with the largest tank

1. For SC_{Height} (ft), calculate the displacement from additional rectangular tanks, Tank 2, 3, 4, etc., to be located with the largest tank in the dike or berm
2. Calculate the total displacement volume from the additional rectangular tanks in the dike or berm

Disclaimer: Please note that these are simplified calculations for qualified facilities that assume: 1) the secondary containment is designed with a flat floor; 2) the wall height is equal for all four walls; and 3) the corners of the secondary containment system are 90 degrees. Additionally, the calculations do not include displacement for support structures or foundations. For Professional Engineer (PE) certified Plans, the PE may need to account for site-specific conditions associated with the secondary containment structure which may require modifications to these sample calculations to ensure good engineering practice.

Spill Prevention Control and Countermeasure (SPCC) Plan

Construct New Secondary Containment

WORKSHEET

A. Determining required dike or berm dimensions for largest single tank

1. Calculate the volume of the tank

Largest Tank Shell Capacity (gal) = [ ] **a**

Largest Tank Volume (ft^3) = [ ] a (gal) ÷ 7.48 gal/ft^3

= [0] **b** ft^3

Note that state and local fire and safety codes may prescribe limits on the height of containment walls, minimum separation distances between tanks, and setback distances. For instance, Occupational Safety and Health Administration (OSHA) flammable and combustible liquids standards in 29 CFR 1910.106 prescribe separation distances between adjacent tanks. Such requirements may present constraints on the location, dimensions, and configuration of the secondary containment structure. The footprint of the tank or tanks and arrangement of the tanks when there is to be more than a single tank within secondary containment may also present constraints on the containment dimensions.

2. Specify the containment wall height and one containment lateral dimension D1 to calculate lateral dimension D2

Note: NaN = Not A Number. Once values **b**, **c, and e** are inputted, NaN will be replaced with the correct value for **f**.

Height of Containment Wall, SC_{Height} (ft) = [ ] **c** ft

Height of Containment Wall, SC_{Height} (in) = [ ] c (ft) x 12 in/ft

= [0] **d** in

D1 (ft) = [ ] e ft

D2 (ft) = [ ] b (ft^3) ÷ [ ] c (ft) ÷ [ ] e (ft) = [NaN] **f** ft

***b** is the volume of the largest tank calculated in Step 1.*

Spill Prevention Control and Countermeasure (SPCC) Plan

Construct New Secondary Containment

WORKSHEET

3. Calculate the volume of rain, V_{Rain} to be collected in the secondary containment with area A_{SC} for the specified rain event

Selected Rainfall Event: *Rainfall (in)* = [ ] in
g

***f** is lateral dimension D2 calculated in Step 2.*

A_{SC} (ft^2) = [ ] (e (ft)) x [ ] (f (ft)) = [0] (**h**) ft^2

V_{Rain} (ft^3) = [ ] (g (in)) ÷ 12 (in/ft) x [ ] (h (ft^2))

= [0] (**i**) ft^3

4. Calculate the required secondary containment volume, V_{SCReq} to account for the additional volume of rain, V_{Rain}

***b** is the volume of the largest tank calculated in Step 1.*

***i** is the volume of rain calculated in Step 3.*

V_{SCReq} (ft^3) = [ ] (b (ft^3)) + [ ] (i (ft^3)) = [0] (**j**) ft^3

Vary the secondary containment height and lateral dimensions, or footprint, in Step 2 to meet any space or dimension constraints or requirements and the required containment volume, V_{SCReq}, by using V_{SCReq} in place of the volume of the largest shell capacity tank, **b** in Step 2.

IF APPLICABLE: When other tanks or containers are also to be located within the secondary containment along with the largest tank, calculate the displacement volumes from these other tanks or containers using Parts B, C and D as applicable. Add the total displacement volume from the other tanks or containers to the volume of rain, V_{Rain}, and the largest tank volume, **b**, in Step 1, to obtain a net secondary containment volume, V_{NetSC}:

V_{NetSC} (ft^3) = [ ] (j (ft^3)) + [ ] (Total Displacement Volume (ft^3)) = [0] (**k**) ft^3

Vary the secondary containment height and lateral dimensions, or footprint, in Step 2 to meet any space or dimension constraints or requirements and the net required containment volume, V_{NetSC}, by using V_{NetSC} in place of the volume of the largest shell capacity tank, **b**.

Spill Prevention Control and Countermeasure (SPCC) Plan

Construct New Secondary Containment

WORKSHEET

B. <u>Accounting for the displacements from other vertical cylindrical tanks to be located in dike or berm with the largest tank</u>

1. For SC_{Height} (ft), calculate the displacement from additional vertical cylindrical tanks, Tank 2, 3, 4, etc., to be located with the largest tank in the dike or berm

Diameter of Tank 2 (ft) = [ ] **l**

Radius of Tank 2 (ft) = [ ] (l (ft)) ÷ 2 = [0] ft **m**

Displacement Area, $DA_{Tank\ 2}$ (ft^2) = 3.14 (π) x [( )^2] (m (ft))

= [0] ft^2 **n**

Displacement Volume, $DV_{Tank\ 2}$ (ft^3) = [ ] (n (ft^2)) x [ ] (c (ft))

c *is the containment wall height used in Step 2 of A.*

= [0] ft^3 **o**

Repeat to calculate the displacement of each additional horizontal cylindrical tank located with the largest tank in the dike or berm.

2. Calculate the total displacement volume from the additional vertical cylindrical tanks in the dike or berm

Total Displacement Volume (ft^3) = [ ] (o (ft^3)) + [ ] (o1 (ft^3)) + [ ] (o2 (ft^3)) + ...

o *is the displacement volume of Tank 2 calculated in Step 1 of B.*

= [0] ft^3 **p**

Spill Prevention Control and Countermeasure (SPCC) Plan

Construct New Secondary Containment

WORKSHEET

C. Accounting for the displacements from other horizontal cylindrical tanks to be located in dike or berm with the largest tank

1. For SC_{Height} (ft), calculate the displacement from additional horizontal cylindrical tanks, Tank 2, 3, 4, etc., to be located with the largest tank in the dike or berm

The easiest way to determine the displacement volume for a horizontal cylindrical tank is to use the tank manufacturer's liquid height to gallons conversion chart for the tank in Method 1 calculation. If this information is not available, use Method 2 calculation to obtain the displacement volumes.

METHOD 1

Height of Tank 2 Below Containment Wall (in) = [ ] in

$V_{Tank\ 2}$ *Displacement (gal) From Tank Conversion Chart* = [ ] gal
q

$V_{Tank\ 2}$ *Displacement* (ft^3) = [ ] (q (gal)) x 0.1337 (ft^3/gal) = [0] (ft^3) **r**

Repeat to calculate the displacement of each additional horizontal cylindrical tank located with the largest tank in the dike or berm.

Total Displacement Volume (ft^3) = [ ] (r (ft^3)) + [ ] (r1 (ft^3)) + [ ] (r2 (ft^3)) + ...

= [0] (ft^3)
s

METHOD 2

Height of Tank 2 Below Containment Wall (in) = [ ] in
t

Tank 2 Diameter (in) = [ ] (Diameter (ft)) x 12 (in/ft) = [0] in **u**

Height to Diameter Ratio for Tank 2 = [ ] (t (in)) ÷ [ ] (u (in)) = [NaN] **v**

Tank 2 Volume Fraction for Height to Diameter Ratio (Table) = [ ]
w

If the tank shell capacity in gallons is known:

Tank Volume $V_{Tank\ 2}$ (ft^3) = [ ] (Shell Capacity (gal)) x 0.1337 (ft^3/gal) = [0] (ft^3) **x**

Spill Prevention Control and Countermeasure (SPCC) Plan

Construct New Secondary Containment

WORKSHEET

METHOD 2 (CONT)

Or, if the tank shell capacity in gallons is not known:

Tank 2 radius (ft) = [ ] ÷ 2 = [0] ft
Diameter (ft)

$V_{Tank\ 2}$ *(ft³)* = 3.14 x [( )²] x [ ] = [0] ft³
Radius (ft) — Tank Length (ft) — **y**

Displacement, $V_{Tank\ 2}$ *(ft³)* = [ ] x [ ] = [0] ft³
x or y (ft³) — w — **z**

Repeat to calculate the displacement volume of each additional horizontal cylindrical tank to be located with the largest tank in the dike or berm.

2. Calculate the total displacement volume from the additional horizontal cylindrical tanks in the dike or berm

Total Displacement Volume (ft³) = [ ] + [ ] + [ ] + ...
z (ft³) — z1 (ft³) — z2 (ft³)

***z** is the displacement volume calculated in Step 1, Method 2 of C.*

= [0] ft³
aa

Spill Prevention Control and Countermeasure (SPCC) Plan

Construct New Secondary Containment

WORKSHEET

D. Accounting for the displacements from other rectangular tanks to be located in dike or berm with the largest tank

1. For SC_{Height} (ft), calculate the displacement from additional rectangular tanks, Tank 2, 3, 4, etc., to be located with the largest tank in the dike or berm

Height of Tank 2 Below Containment Wall (ft) = [ ] ft
ab

Length of Tank 2 (ft) = [ ]
ac

Width of Tank 2 (ft) = [ ]
ad

Displacement Area, $DA_{Tank\ 2}$ (ft^2) = [ ] x [ ] = [0] ft^2
ac (ft) ad (ft) **ae**

Displacement Volume, $DV_{Tank\ 2}$ (ft^3) = [ ] x [ ]
ae (ft^2) ab (ft)

= [0] ft^3
af

Repeat to calculate the displacement area and volume of each additional rectangular tank to be located with the largest tank in the dike or berm.

2. Calculate the total displacement volume from the additional rectangular tanks in the dike or berm

Total Displacement Volume (ft^3) = [ ] + [ ] + [ ] + ...
***af** is the displacement volume calculated in Step 1 of D.*
af (ft^3) af1 (ft^3) af2 (ft^3)

= [0] ft^3
ag

Spill Prevention Control and Countermeasure (SPCC) Plan

Construct New Secondary Containment

WORKSHEET

Please use the space below to sketch tanks and wall dimensions to assist with calculations.

Spill Prevention Control and Countermeasure (SPCC) Plan

Multiple Horizontal Cylindrical Tanks Inside a Rectangular or Square Dike or Berm

WORKSHEET

This worksheet can be used to calculate the containment volume of a rectangular or square dike or berm for multiple horizontal cylindrical tanks. When there are other objects or structures such as tanks along with the largest tank within the dike or berm, their respective displacement volumes must be accounted for when determining secondary containment.

Steps:

1. Determine the volume of the secondary containment, V_{SC}

2a. Determine the volume of the tank when the tank shell capacity is unknown, V_{Tank}

2b. Determine the volume of the tank when shell capacity is known, V_{Tank}

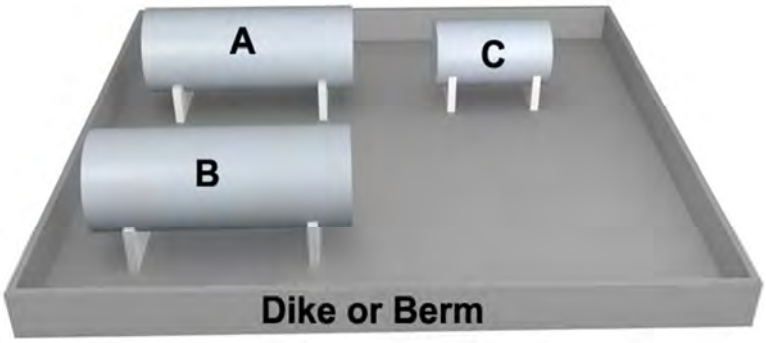
3. Determine the unavailable (displacement) areas and volumes in the containment due to other tanks within the containment and the net containment volume remaining for the largest tank

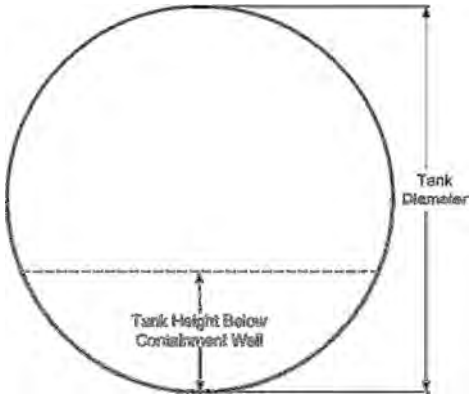
4. Determine the percentage of the net secondary containment volume, V_{SCNet}, to the largest tank volume, V_{Tank}

5. Determine whether the secondary containment can contain the entire tank shell capacity with additional capacity to contain rain.

Information needed to use this worksheet:

- Tank shell capacity in gallons or tank diameter and length of the largest tank in feet
- Secondary containment length, width, and height in feet
- Shell capacity in gallons or length and diameter of each of the other tanks in feet within the secondary containment
- Height in feet of each tank below top of containment wall
- If rain can collect in secondary containment: amount of rain, inches or feet, for the location





Largest Tank Shell Capacity (gal) = [ ]
a

Disclaimer: Please note that these are simplified calculations for qualified facilities that assume: 1) the secondary containment is designed with a flat floor; 2) the wall height is equal for all four walls; and 3) the corners of the secondary containment system are 90 degrees. Additionally, the calculations do not include displacement for support structures or foundations. For Professional Engineer (PE) certified Plans, the PE may need to account for site-specific conditions associated with the secondary containment structure which may require modifications to these sample calculations to ensure good engineering practice.

Spill Prevention Control and Countermeasure (SPCC) Plan

Multiple Horizontal Cylindrical Tanks Inside a Rectangular or Square Dike or Berm

WORKSHEET

1. Determine the volume of the secondary containment, V_{SC}

Secondary Containment Area, A_{SC} = [ ] x [ ]
Length (ft) — Width (ft)

= [0] ft^2
b

V_{SC} (ft^3) = [ ] x [ ] = [0] ft^3
b (ft^2) — Height (ft) — **c**

2a. Determine the volume of the tank when the tank shell capacity is unknown, V_{Tank}

Tank radius (ft) = [ ] ÷ 2 = [0] ft
Diameter (ft)

V_{Tank} (ft^3) = 3.14 x [( )^2] x [ ] = [0] ft^3
Radius^2 $(ft)^2$ — Tank Length (ft) — **d**

2b. Determine the volume of the tank when shell capacity is known, V_{Tank}

***a** is the tank shell capacity from page 1.*

V_{Tank} (ft^3) = [ ] x 0.1337 = [0] ft^3
a (gal) — ft^3/gal — **e**

3. Determine the unavailable (displacement) areas and volumes in the containment due to other tanks within the containment and the net containment volume remaining for the largest tank

The easiest way to determine the displacement volume for a horizontal cylindrical tank is to use the tank manufacturer's liquid height to gallons conversion chart for the tank in Method 1 calculation. If this information is not available, use Method 2 calculation to obtain the displacement volumes.

Spill Prevention Control and Countermeasure (SPCC) Plan

Multiple Horizontal Cylindrical Tanks Inside a Rectangular or Square Dike or Berm

WORKSHEET

METHOD 1

Height of Tank B Below Containment Wall (in) = [ ] in

$V_{Tank\ B}$ *Displacement (gal) From Tank Conversion Chart* = [ ] gal
f

$V_{Tank\ B}$ *Displacement* (ft^3) = [ ] x 0.1337 = [0] ft^3
f (gal) ft^3/gal **g**

Calculate the displacement of each additional horizontal cylindrical tank within the same secondary containment:

Total Displacement Volume (ft^3) = [ ] + [ ] + [ ] + ...
g (ft^3) g1 (ft^3) g2 (ft^3)

= [0] ft^3
h

METHOD 2

Height of Tank B Below Containment Wall (in) = [ ] in
i

Tank B Diameter (in) = [ ] x 12 = [0] in
Diameter (ft) in/ft **j**

Height to Diameter Ratio for Tank B = [ ] ÷ [ ] = [NaN]
i (in) j (in) **k**

Tank B Volume Fraction for Height to Diameter Ratio (Table) = [ ]
l

<u>If the tank shell capacity in gallons is known:</u>

Tank Volume $V_{Tank\ B}$ (ft^3) = [ ] x 0.1337 = [0] ft^3
Shell Capacity (gal) ft^3/gal **m**

Spill Prevention Control and Countermeasure (SPCC) Plan

Multiple Horizontal Cylindrical Tanks Inside a Rectangular or Square Dike or Berm

WORKSHEET

METHOD 2 (CONT)

Or, if the tank shell capacity in gallons is not known:

Tank B radius (ft) = [ ] ÷ 2 = [0] ft
Diameter (ft)

$V_{Tank\ B}$ *(ft³)* = 3.14 x [( )²] x [ ] = [0] ft³
Radius (ft) — Tank Length (ft) — **n**

Displacement, $V_{Tank\ B}$ *(ft³)* = [ ] x [ ] = [0] ft³
m (ft³) — l — **o**

m *is the tank volume.*
l *is the Tank B volume fractionfor H/D ratio (table).*

Calculate the displacement of each additional horizontal cylindrical tank within the same secondary containment:

Total Displacement Volume (ft³) = [ ] + [ ] + [ ] + ...
o (ft³) — o1 (ft³) — o2 (ft³)

= [0] ft³
p

Net Secondary Containment Volume:

Net Containment Volume, V_{SCNet} *(ft³)* = [ ] — [ ] = [0] ft³
c (ft³) — h (Method 1) or p (Method 2) (ft³) — **q**

c *is the secondary contianment volume calculated in Step 1.*
h/p *is the total displacement volume.*

Spill Prevention Control and Countermeasure (SPCC) Plan

Multiple Horizontal Cylindrical Tanks Inside a Rectangular or Square Dike or Berm

WORKSHEET

4. Determine the percentage of the net secondary containment volume, V_{SCNet} to the largest tank volume, V_{Tank}[1] (to determine whether the volume of the containment is sufficient to contain the largest tank's entire shell capacity).

Note: NaN = Not A Number. Once values **q** and **e** are inputted, NaN will be replaced with the correct value for **r**.

V_{SCNet}/V_{Tank} = [ ] ÷ [ ] = [NaN]

__q__ is the net secondary contianment volume calculated in Step 3, Method 2.
__e__ is the tank volume calculated in Step 2.

q (ft^3) | e (ft^3) | **r**

% = [ ] x 100 = [0]

r | **s**

If percentage, **s**, is 100% or greater, the capacity of the secondary containment is sufficient to contain the shell capacity of the tank. If rain can collect in the dike or berm, continue to step 4. If percentage, **s**, is less than 100%, the capacity of the secondary containment is not sufficient to contain the shell capacity of the tank.

5. Determine whether the secondary containment can contain the entire tank shell capacity with additional capacity to contain rain.

If rain can collect in a dike or berm, the SPCC rule requires that secondary containment for bulk storage containers have additional capacity to contain rainfall or freeboard. The rule does not specify a method to determine the additional capacity required to contain rain or the size of the rain event for designing secondary containment. However, industry practice often considers a rule of thumb of 110% of the tank capacity to account for rainfall. A dike with a 110% capacity of the tank may be acceptable depending on, the shell size of the tank, local precipitation patterns and frequency of containment inspections. In a different geographic area, a dike or berm designed to hold 110% for the same size tank may not have enough additional containment capacity to account for a typical rain event in that area. The 110% standard may also not suffice for larger storm events. If you want to determine a conservative capacity for a rain event, you may want to consider a 24-hour 25-year storm event. It is the responsibility of the owner or operator[2] to determine the additional containment capacity necessary to contain rain. A typical rain event may exceed the amount determined by using a 110% "rule of thumb" so it is important to consider the amount of a typical rain event when designing or assessing your secondary containment capacity.

Rainfall data may be available from various sources such as local water authorities, local airports, and the National Oceanic and Atmospheric Administration (NOAA).

[1] Steps 4 and 5 in the worksheet determines whether the net volume of the secondary containment is sufficient to contain the largest tank's entire shell capacity and rainfall (freeboard for precipitation) as required by the SPCC rule. Step 4 primarily determines whether the net volume of the secondary containment is sufficient to contain the entire shell capacity of the largest tank. Step 5 is necessary to determine whether the secondary containment can also contain the expected volume of rainfall (both the volume of rain that falls into the containment plus the rain from the tank storage site).

[2] The SPCC rule does not require you to show the secondary containment calculations in your Plan. However, you should maintain documentation of secondary containment calculations to demonstrate compliance to an EPA inspector.

Spill Prevention Control and Countermeasure (SPCC) Plan

Multiple Horizontal Cylindrical Tanks Inside a Rectangular or Square Dike or Berm

WORKSHEET

Selected Rainfall Event:

Rainfall (in) = [ ] in
t

Rainfall (ft) = [ ] ÷ 12
t (in) in/ft

[0] ft
u

Volume of Rain to be Contained, V_{Rain} (ft^3) = [ ] x [ ] = [0] ft^3
b *is the area of secondary containment calculated in Step 1.*
u (ft) b (ft^2) **v**

Total Containment Capacity Required (ft^3) = [ ] + [ ]
e *is the tank volume calculated in Step 2.*
v (ft^3) e (ft^3)

[0] ft^3
w

If the net secondary containment volume after accounting for displacements, **q**, is equal to or greater than the required containment capacity, **w**, the secondary containment is sufficient to contain the shell capacity of the largest tank with sufficient additional capacity to contain a typical rainfall amount. If the net secondary containment volume after accounting for displacements, **q**, is less than the required containment capacity, **w**, the secondary containment is not sufficient to contain the shell capacity of the largest tank and a typical rainfall amount.

Spill Prevention Control and Countermeasure (SPCC) Plan

Multiple Horizontal Cylindrical Tanks Inside a Rectangular or Square Dike or Berm

WORKSHEET

Table of H/D Ratios and Corresponding Percent of Tank Volume

"H" is the tank height below the top of the containment wall. "D" is the tank diameter.

H/D Ratio	Percent of Tank Vol	H/D ratio	Percent of Tank Vol	H/D ratio	Percent of Tank Vol
0	0	0.34	0.301	0.68	0.724
0.01	0.002	0.35	0.312	0.69	0.737
0.02	0.003	0.36	0.323	0.70	0.747
0.03	0.009	0.37	0.337	0.71	0.760
0.04	0.013	0.38	0.348	0.72	0.770
0.05	0.020	0.39	0.362	0.73	0.783
0.06	0.025	0.40	0.374	0.74	0.792
0.07	0.030	0.41	0.385	0.75	0.805
0.08	0.038	0.42	0.400	0.76	0.816
0.09	0.045	0.43	0.411	0.77	0.825
0.10	0.053	0.44	0.423	0.78	0.837
0.11	0.058	0.45	0.435	0.79	0.848
0.12	0.068	0.46	0.450	0.80	0.858
0.13	0.075	0.47	0.461	0.81	0.869
0.14	0.085	0.48	0.473	0.82	0.879
0.15	0.094	0.49	0.488	0.83	0.888
0.16	0.102	0.50	0.500	0.84	0.898
0.17	0.112	0.51	0.512	0.85	0.906
0.18	0.121	0.52	0.527	0.86	0.915
0.19	0.131	0.53	0.539	0.87	0.925
0.20	0.142	0.54	0.550	0.88	0.932
0.21	0.152	0.55	0.565	0.89	0.942
0.22	0.163	0.56	0.577	0.90	0.947
0.23	0.175	0.57	0.589	0.91	0.955
0.24	0.184	0.58	0.600	0.92	0.962
0.25	0.195	0.59	0.615	0.93	0.970
0.26	0.208	0.60	0.626	0.94	0.975
0.27	0.217	0.61	0.638	0.95	0.980
0.28	0.230	0.62	0.652	0.96	0.987
0.29	0.240	0.63	0.663	0.97	0.991
0.30	0.253	0.64	0.677	0.98	0.997
0.31	0.263	0.65	0.688	0.99	0.998
0.32	0.276	0.66	0.699	1.00	1.000
0.33	0.287	0.67	0.713		

Spill Prevention Control and Countermeasure (SPCC) Plan

Rectangular or Square Remote Impoundment Structure

WORKSHEET

This worksheet can be used to calculate the containment volume of a rectangular or square remote impoundment[1] structure providing secondary containment for an aboveground tank storage facility.

Steps:

1. Determine the volume of the secondary containment impoundment, V_{SC}

2a. Determine the volume of the largest tank when shell capacity is unknown, V_{Tank}

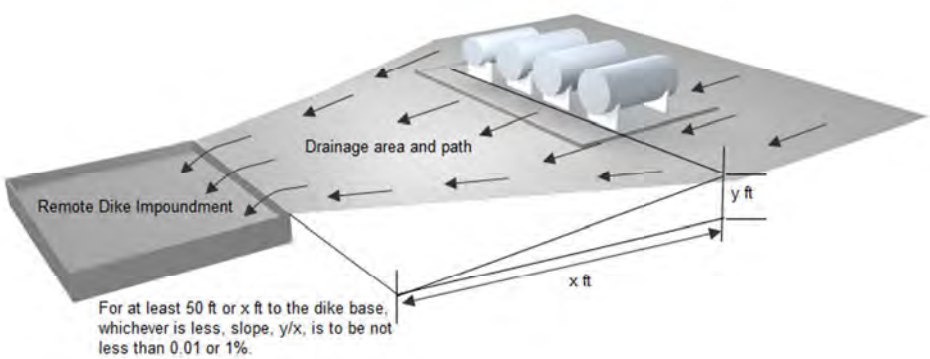
2b. Determine the volume of the largest tank when shell capacity is known, V_{Tank}

3. Determine the percentage of the secondary containment volume, $V_{SC,}$ to the largest tank volume, V_{Tank}

4. Determine whether the secondary containment impoundment can contain the entire tank shell capacity of the largest tank with additional capacity to contain rain.

Information needed to use this worksheet:

- Tank shell capacity in gallons or tank diameter and length or height in feet of the largest tank
- Remote impoundment length, width, and height in feet
- If rain can collect in impoundment: amount of rain, inches or feet
- If rain can collect in drainage area with runoff in the area flowing into the impoundment, this amount must also be considered in the additional impoundment capacity to contain rain. The surface drainage area in square feet is required.



Largest Tank Shell Capacity (gal) = [ ]

a

Disclaimer: Please note that these are simplified calculations for qualified facilities that assume: 1) the secondary containment is designed with a flat floor; 2) the wall height is equal for all four walls; and 3) the corners of the secondary containment system are 90 degrees. Additionally, the calculations do not include displacement for support structures or foundations. For Professional Engineer (PE) certified Plans, the PE may need to account for site-specific conditions associated with the secondary containment structure which may require modifications to these sample calculations to ensure good engineering practice.

[1] Remote impounding is an acceptable secondary containment method under NFPA 30 because the code primarily focuses on fire safety and emphasizes the importance of moving leaked or spilled flammable liquids away from the tank by adequate draining. A remote impoundment must be able to contain the contents of the largest tank. However, when this is not possible, partial impounding can be used in combination with diking to meet the largest-tank criterion.

For tank fields contained by diking, NFPA 30 requires that a slope of not less than one percent away from the tank shall be provided for at least 50 feet or to the dike base, whichever is less. This ensures that small spills will not accumulate against the wall of the tank. Also, if remote impounding is used, the drainage path to the impoundment should be designed so that if the drainage path is ignited, the flames will not pose serious risk to tanks or adjoining property.

Spill Prevention Control and Countermeasure (SPCC) Plan

Rectangular or Square Remote Impoundment Structure

WORKSHEET

1. Determine the volume of the secondary containment impoundment, V_{SC}

Impoundment Containment Area, A_{SC} = [ ] x [ ]
Length (ft) — Width (ft)

= [0] ft^2
b

V_{SC} (ft^3) = [0] x [ ] = [ ] ft^3
b (ft^2) — Height (ft) — **c**

2a. Determine the volume of the largest tank when the shell capacity is unknown, V_{Tank}

Tank radius (ft) = [0] ÷ 2 = [ ] ft
Diameter (ft)

V_{Tank} (ft^3) = 3.14 x [(0)^2] x [ ] = [ ] ft^3
Radius^2 (ft)^2 — Tank Height (ft) — **d**

2b. Determine the volume of the largest tank when shell capacity is known, V_{Tank}

***a** is the tank shell capacity from page 1.*

V_{Tank} (ft^3) = [0] x 0.1337 = [ ] ft^3
a (gal) — ft^3/gal — **e**

Spill Prevention Control and Countermeasure (SPCC) Plan

Rectangular or Square Remote Impoundment Structure

WORKSHEET

3. Determine the percentage of the secondary containment volume, V_{SC}, to the largest tank volume, V_{Tank}[2](to determine whether the volume of the containment is sufficient to contain the largest tank's entire shell capacity).

Note: NaN = Not A Number. Once values **c** and **d**/**e** are inputted, NaN will be replaced with the correct value for **f**.

c is the secondary containment volume calculated in Step 1.
***d** / **e** is the tank volume calculated in Step 2.*

V_{SC}/V_{Tank} = [0] ÷ [ ] = [ ]

c (ft^3) | d or e (ft^3) | **f**

% = [0] x 100 = [0]

f | **g**

If the percentage, **g**, is 100% or greater, the capacity of the impoundment containment is sufficient to contain the shell capacity of the largest tank. If rain can collect in the impoundment, continue to step 4. If the percentage, **g**, is less than 100%, the capacity of the impoundment containment is not sufficient to contain the shell capacity of the largest tank.

4. Determine whether the secondary containment impoundment can contain the entire tank shell capacity with additional capacity to contain rain.

If rain can collect in a remote impoundment structure, the SPCC rule requires that secondary containment for bulk storage containers have additional capacity to contain rainfall or freeboard. The rule does not specify a method to determine the additional capacity required to contain rain or the size of the rain event for designing secondary containment. However, industry practice often considers a rule of thumb of 110% of the tank capacity to account for rainfall. A dike with a 110% capacity of the tank may be acceptable depending on, the shell size of the tank, local precipitation patterns and frequency of containment inspections. In a different geographic area, a dike or berm designed to hold 110% for the same size tank may not have enough additional containment capacity to account for a typical rain event in that area. The 110% standard may also not suffice for larger storm events. If you want to determine a conservative capacity for a rain event, you may want to consider a 24-hour 25-year storm event. It is the responsibility of the owner or operator[3] to determine the additional containment capacity necessary to contain rain. A typical rain event may exceed the amount determined by using a 110% "rule of thumb" so it is important to consider the amount of a typical rain event when designing or assessing your secondary containment capacity.

Rainfall data may be available from various sources such as local water authorities, local airports, and the National Oceanic and Atmospheric Administration (NOAA).

[2] Steps 3 and 4 in the worksheet determines whether the volume of the impoundment containment is sufficient to contain the largest tank's entire shell capacity and rainfall (freeboard for precipitation) as required by the SPCC rule. Step 3 primarily determines whether the volume of the impoundment containment is sufficient to contain the entire shell capacity of the largest tank. Step 4 is necessary to determine whether the impoundment containment can also contain the expected volume of rainfall (both the volume of rain that falls into the impoundment plus the rain from the drainage area contributing runoff into the impoundment).

[3] The SPCC rule does not require you to show the secondary containment calculations in your Plan. However, you should maintain documentation of secondary containment calculations to demonstrate compliance to an EPA inspector.

Spill Prevention Control and Countermeasure (SPCC) Plan

Rectangular or Square Remote Impoundment Structure

WORKSHEET

Selected Rainfall Event:

Rainfall (in) = [ ] in
h

Rainfall (ft) = [ ] ÷ 12
h (in) in/ft

= [ ] ft
i

Volume of rain, $V_{RainImpound}$, that can fall directly into the impoundment:

$V_{RainImpound}$ *(ft^3)* = [ ] x [ ] = [0] ft^3
i (ft) b (ft^2) **j**

***b** is the area of secondary containment calculated in Step 1.*

Volume of rain contributed from the Impoundment Drainage Area, $V_{DrainageArea}$, to the remote impoundment: (The drainage surface area, $A_{DrainageArea}$, contributing rain runoff into the remote dike impoundment in ft^2 is required to determine $V_{DrainageArea}$. This information can be obtained from the as-built plans for the design and construction of the impoundment).

Area of Drainage, $A_{DrainageArea}$ (ft^2) = [ ] ft^2
k

$V_{DrainageArea}$ *(ft^3)* = [ ] x [ ] = [ ] ft^3
i (ft) k (ft^2) **l**

Total Volume of Rain Collected in Impoundment, $V_{TotalRainImpound}$:

$V_{TotalRainImpound}$ *(ft^3)* = [ ] + [0] = [ ] ft^3
j (ft^3) l (ft^3) **m**

Total Containment Capacity Required (ft^3) = [ ] + [ ]
m (ft^3) e (ft^3)

***e** is the tank volume calculated in Step 2.*

= [NaN] ft^3
n

If the volume of the impoundment containment, **c**, is equal to or greater than the required containment capacity, **n**, the impoundment is sufficient to contain the shell capacity of the largest tank with sufficient additional capacity to contain a typical rainfall amount. If the volume of the impoundment containment, **c**, is less than the required containment capacity, **n**, the impoundment containment is not sufficient to contain the shell capacity of the largest tank and a typical rainfall amount.

Spill Prevention Control and Countermeasure (SPCC) Plan

Single Vertical Cylindrical Tank Inside a Rectangular or Square Dike or Berm

WORKSHEET

This worksheet can be used to calculate the secondary containment volume of a rectangular or square dike or berm for a single vertical cylindrical tank. This worksheet assumes that there are no other objects or structures within the dike or berm that will displace the volume of the secondary containment.

Steps:

1. Determine the volume of the secondary containment, V_{SC}

2a. Determine the volume of the tank when the tank shell capacity is unknown, V_{Tank}

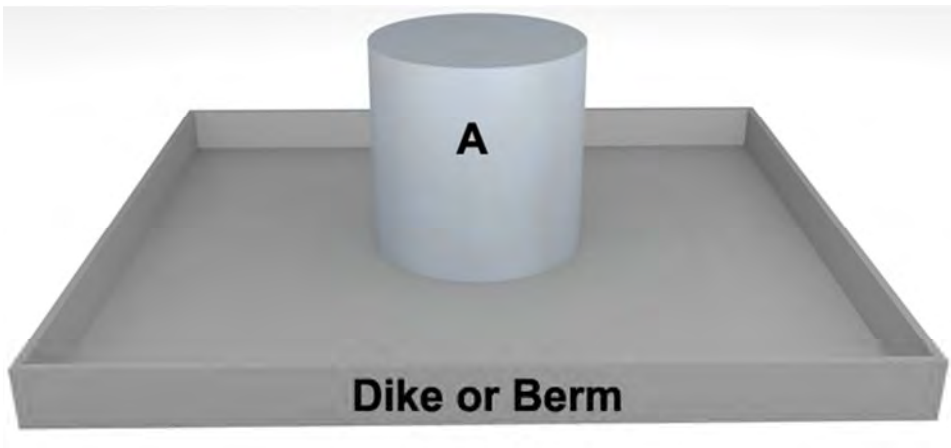
2b. Determine the volume of the tank when shell capacity is known, V_{Tank}

3. Determine the percentage of the secondary containment volume, V_{SC}, to the tank volume, V_{Tank}

4. Determine whether the secondary containment can contain the entire tank shell capacity with additional capacity to contain rain.

Information needed to use this worksheet:

- Tank shell capacity in gallons or tank diameter and height in feet
- Secondary containment length, width, and height in feet
- If rain can collect in secondary containment: amount of rain in inches or feet



Tank A Shell Capacity (gal) = [ ]
a

Disclaimer: Please note that these are simplified calculations for qualified facilities that assume: 1) the secondary containment is designed with a flat floor; 2) the wall height is equal for all four walls; and 3) the corners of the secondary containment system are 90 degrees. Additionally, the calculations do not include displacement for support structures or foundations. For Professional Engineer (PE) certified Plans, the PE may need to account for site-specific conditions associated with the secondary containment structure which may require modifications to these sample calculations to ensure good engineering practice.

Spill Prevention Control and Countermeasure (SPCC) Plan

Single Vertical Cylindrical Tank Inside a Rectangular or Square Dike or Berm

WORKSHEET

1. Determine the volume of the secondary containment, V_{SC}

Secondary Containment Area, A_{SC} = [ ] x [ ]
Length (ft) — Width (ft)

= [0] ft^2
b

V_{SC} (ft^3) = [ ] x [ ] = [0] ft^3
b (ft^2) — Height (ft) — **c**

2a. Determine the volume of the tank when the tank shell capacity is unknown, V_{Tank}

Tank radius (ft) = [ ] ÷ 2 = [0] ft
Diameter (ft)

V_{Tank} (ft^3) = 3.14 x [( )^2] x [ ] = [0] ft^3
Radius^2 $(ft)^2$ — Tank Height (ft) — **d**

2b. Determine the volume of the tank when shell capacity is known, V_{Tank}

***a** is the tank shell capacity from page 1.*

V_{Tank} (ft^3) = [ ] x 0.1337 = [0] ft^3
a (gal) — ft^3/gal — **e**

Spill Prevention Control and Countermeasure (SPCC) Plan

Single Vertical Cylindrical Tank Inside a Rectangular or Square Dike or Berm

WORKSHEET

3. Determine the percentage of the secondary containment volume, V_{SC}, to the tank volume, V_{Tank}[1](to determine whether the volume of the containment is sufficient to contain the tank's entire shell capacity).
Note: NaN = Not A Number. Once values **c** and **d/e** are inputted, NaN will be replaced with the correct value for **f**.

__c__ is the secondary containment volume calculated in Step 1.
__d__ / __e__ is the tank volume calculated in Step 2.

V_{SC}/V_{Tank} = [ ] ÷ [ ] = [0]

c (ft^3) — d or e (ft^3) — **f**

% = [ ] x 100 = [ ]

f — **g**

If percentage, **g**, is 100% or greater, the capacity of the secondary containment is sufficient to contain the shell capacity of the tank. If rain can collect in the dike or berm, continue to step 4. If percentage, **g**, is less than 100%, the capacity of the secondary containment is not sufficient to contain the shell capacity of the tank.

4. Determine whether the secondary containment can contain the entire tank shell capacity with additional capacity to contain rain.

If rain can collect in a dike or berm, the SPCC rule requires that secondary containment for bulk storage containers have additional capacity to contain rainfall or freeboard. The rule does not specify a method to determine the additional capacity required to contain rain or the size of the rain event for designing secondary containment. However, industry practice often considers a rule of thumb of 110% of the tank capacity to account for rainfall. A dike with a 110% capacity of the tank may be acceptable depending on, the shell size of the tank, local precipitation patterns and frequency of containment inspections. In a different geographic area, a dike or berm designed to hold 110% for the same size tank may not have enough additional containment capacity to account for a typical rain event in that area. The 110% standard may also not suffice for larger storm events. If you want to determine a conservative capacity for a rain event, you may want to consider a 24-hour 25-year storm event. It is the responsibility of the owner or operator[2] to determine the additional containment capacity necessary to contain rain. A typical rain event may exceed the amount determined by using a 110% "rule of thumb" so it is important to consider the amount of a typical rain event when designing or assessing your secondary containment capacity.

Rainfall data may be available from various sources such as local water authorities, local airports, and the National Oceanic and Atmospheric Administration (NOAA).

[1]Steps 3 and 4 in the worksheet determine whether the volume of the secondary containment is sufficient to contain the tank's entire shell capacity and rainfall (freeboard for precipitation) as required by the SPCC rule. Step 3 primarily determines whether the volume of the secondary containment is sufficient to contain the entire shell capacity of the tank. Step 4 is necessary to determine whether the secondary containment can also contain the expected volume of rainfall (both the volume of rain that falls into the containment plus the rain from the tank storage site).

[2] The SPCC rule does not require you to show the secondary containment calculations in your Plan. However, you should maintain documentation of secondary containment calculations to demonstrate compliance to an EPA inspector.

Spill Prevention Control and Countermeasure (SPCC) Plan

Single Vertical Cylindrical Tank Inside a Rectangular or Square Dike or Berm

WORKSHEET

Selected Rainfall Event:

Rainfall (in) = [ ] in
h

Rainfall (ft) = [ ] ÷ 12
h (in) in/ft

= [0] ft
i

Volume of Rain to be Contained, V_{Rain} (ft^3) = [ ] x [ ] = [0] ft^3
b *is the area of secondary containment calculated in Step 1.*
i (ft) b (ft^2) **j**

Total Containment Capacity Required (ft^3) = [ ] + [NaN]
d/e *is the tank volume calculated in Step 2.*
j (ft^3) d or e (ft^3)

= [ ] ft^3
k

If the volume of the secondary containment, **c**, is equal to or greater than the required containment capacity, **k**, the secondary containment is sufficient to contain the shell capacity of the tank with sufficient additional capacity to contain a typical rainfall amount. If the volume of the secondary containment, **c**, is less than the required containment capacity, **k**, the secondary containment is not sufficient to contain the shell capacity of the tank and a typical rainfall amount**.**