APPENDIX A - DESCRIPTION OF FACILITY

A-1. INTRODUCTION

A-1.1 The St. James facility is located approximately 45 miles west of New Orleans, 30 miles southeast of Baton Rouge and approximately 160 miles upstream from the mouth of the Mississippi River. For crude oil distribution, the St. James facility is connected to the following sites:

LOCAP distribution site by a direct connection 24 and 36-inch pipeline (see Facility Documentation webpage)
Capline distribution site by a 0.5 mile 30-inch pipeline
Plains distribution by a 24-inch pipeline connection (see Facility Documentation webpage)
A current connection to Acadian Terminal
Bayou Choctaw SPR storage site by a 37.2 mile 36-inch pipeline
Baton Rouge Placid refinery via a 24-inch Shell pipeline at the Bayou Choctaw SPR Site
St. James facility marine docks (quantity 2) via 42-inch on-site lines

A-1.2 De-Commissioned pipelines and other connections at the facility include:

30-inch pipeline connection to the Koch/Nustar facility
36-inch pipeline to Cote Blanche valve station, Weeks Island
Tie-in to Exxon North Line Facility (via Capline 30 Inch pipeline)
Tie-in from Ship Shoal / Texaco pipeline

A-1.3 General crude oil site piping and equipment inside the facility is ANSI 150 Class. Pipelines connected to the site are ANSI 300 Class.

A-2. FACILITY PHYSICAL DESCRIPTION

A-2.1 The St. James facility is comprised of two marine docks on the Mississippi River occupying approximately 48 acres of land, a tank terminal occupying approximately 105 acres of land, one 36” pipeline with connectivity to outside facilities, several connections that lead to other oil transfer facilities plus the environmental and safety systems that serve the entire St. James facility. Locations of facilities are given in segments of US Army Corps of Engineers mappings provided in the solicitation Facilities Drawings online library.

A-2.1.1 Marine Docks. The St. James facility has two marine docks on the Mississippi River, which are located approximately two miles southeast of the tank terminal. Dock 1 is located at Mississippi River milepost 158.3, and Dock 2 is located at Mississippi River milepost 158.0. Both docks are concrete and steel construction with four breasting dolphins and eight mooring dolphins with capstan motors and quick release "pelican hooks." Each dock is equipped with three 16-inch Continental Emsco hydraulic operated loading arms, a 5-ton hydraulic crane, in-line sampler and a control room equipped with operational control, status and monitoring of fluid transfer with Emergency shutdown controls.

A-2.1.1.1 Each dock is connected to the terminal with a 42-inch crude oil line, , a 6-inch oily water return line, and a 2-inch potable water feed line. The terminal's back-up firewater pumping system is located at Dock 1 and supplies primary fire water to both docks

A-2.1.1.2 Right-of-Way. The fee and easement lands comprising the St. James Marine Docks and associated piping are all located in St. James Parish, Louisiana and are identified as Tract Nos. 201-1, 201-3. 210, 211-1, 211-2, 214, 215., 216, 217, 220, 201E-1, 201E-3, 201E-5, 201E-7, 210E-1, 211E-1, 214E, and 218E-1 on Segment 2 of the Bayou Choctaw Facility of US Army Corps of Engineers mapping dated 1/21/1987.

A-2.1.2 Tank Terminal. The tank terminal provides crude oil storage, pumping, metering, and distribution. The tank terminal consists of six storage tanks totaling approximately two million barrels capacity, crude oil pumping stations, metering stations, and control and maintenance facilities.

A-2.1.2.1 Storage Tanks. The six storage tanks have a total shell capacity of approximately 2 million barrels. The tanks are approximately 33 feet high and have a single skin-floating roof. Each of the tanks is equipped with mixers and temperature and level gauging instrumentation. The six tanks are sited in two groups of three, which are each surrounded by a community dike system. Each of the two diked areas could contain the entire volume of one tank with some freeboard allowance. Minor spillage is contained by lower internal dikes between the tanks.

A-2.1.2.2 Primary Pump Station. The primary pump station consists of five Peabody-Floway vertical, deep well, three-stage pumps with a designed capacity at discharge of 25,000-barrels-per-hour at 288 feet of head each. They are driven by 1,500 horsepower electric motors. The pump station is manifolded to provide two independent pumping units of two pumps each: Pumps 1 and 2, and Pumps 4 and 5. Pump 3 is manifolded into both systems as an on-line spare.

A-2.1.2.3 Fill Pumps. The terminal also has a second pumping station which contains three horizontal centrifugal pumps rated at 10,000- barrels-per-hour each at 460 psi discharge that are driven by 1,375 horsepower electric motors.

A-2.1.2.4 Metering and Custody Transfer. The tank terminal has two (quantity) meter stations. Each meter station consists of three 12-inch meter runs equipped with in-line turbine meters having a rated capacity of approximately 18,000-barrels per-hour each. The meters are calibrated and proved by a unidirectional prover loop adjacent to the meter station.

A-2.1.2.5 Buildings. There are five primary buildings at the terminal: Administration Building, Contractor Office Building, Maintenance Building, Spare Parts Warehouse, and Oil Quality Assurance Laboratory. See facility documents to floor plans and sizes of these buildings. In addition, there are several minor buildings such as the Security Center and various small buildings for safety and oil spill equipment.

A-2.1.2.6 Right-of-Way. The fee and easement lands comprising the St. James Terminal are all located in St. James Parish, Louisiana and are identified as Tract Nos. 200-2, 200E-14 and 222E on Segment 2 of the Bayou Choctaw Facility of US Army Corps of Engineers mapping dated 1/21/1987.

A-2.1.3 Bayou Choctaw Pipeline. The FACILITY also includes a 36-inch portion of pipeline between Bayou Choctaw site and St. James Terminal currently known as Redstick and appurtenances thereto. The pipeline is 37.2 miles long. It connects the GOVERNMENT Bayou Choctaw site in Baton Rouge, Louisiana, to the St. James Tank Terminal and Marine Docks.

A-2.1.3.1 Pipeline ownership breakpoint locations at both ends of the pipeline are marked and identified on schematics cited below in the following descriptions.

A-2.1.3.1.1 Bayou Choctaw end of Bayou Choctaw 36” Pipeline. The property responsibility demarcation (Lessee vs. Government) at the Bayou Choctaw site side of the Bayou Choctaw pipeline is as shown on drawing BC-M-103-031 (Exhibit A-2 within). These delineate three zones of responsibility: Shell Pipeline GOVERNMENT-owned Site Piping (GOVERNMENT responsibility), and GOVERNMENT-owned Bayou Choctaw pipeline leased out (LESSEE responsibility). Breaks are at spec blinds downstream of GOVERNMENT valves 4LST1 MOV-03 & -04 feeding the BCSTLR-1 launcher, at spec blinds downstream of GOVERNMENT valves 4LST2 MOV-01 & -04 feeding the BC-Shell launcher, at the spec blind downstream of GOVERNMENT valve 4LST1 MOV-01 feeding the two pipelines, at the spec blind downstream of valve MOVR1 separating the two pipelines, at the 4" drain valve BCLR20DR1 connecting BCSTLR-1 launcher to the drain of the BC-Shell launcher, and at PSV1200 on the BCSTLR-1 launcher.

A-2.1.3.1.2 St James Tank Terminal end of Bayou Choctaw 36" Pipeline. There are no property breaks between the Bayou Choctaw Pipeline and the St. James Facility, delineating responsibilities. The LESSEE is responsible for everything shown in drawing SJ-M-103-018 (can be found in the St. James Facility Drawing Index). Note that this is not the limit of responsibilities. The facility entails more than is depicted in this drawing.

A-2.1.3.1.3 Right-of-Way. The easement lands comprising the Bayou Choctaw Pipeline are all located in various parish and described below:

St. James Parish, Louisiana: Tract Nos. 200E-4, 200E-12, 203E01, 203E-4, 213-L1, and 212E-1 as shown on Segment 2 of the Bayou Choctaw Facility of US Army Corps of Engineers mapping dated 1/21/1987.

Assumption Parish, Louisianan: Tract Nos 202E-1, 204E-1, 205E-1, 205E-3, 206E-1, 207E-1, 208E-1, and 209E-1, 300E-1, 300E-4, 301E-3, 302E-1, 302E-4, 303E-1, and 318E as shown on Segment 2 of the Bayou Choctaw Facility of US Army Corps of Engineers mapping dated 1/21/1987 and on Segment 3 of the Bayou Choctaw Facility of US Army Corps of Engineers mapping dated 2/13/1984.

Ascension Parish, Louisiana: Tract Nos. 301 E-5, 304 E-1, 304 E-3, 305 E-1, 305 E-3, 305 E-7, 305 E-8, 306 E-1, 307 E-1, 308 E-1, 309 E-1, 310 E-1, 311 E-1 as shown on Segment 3 of the Bayou Choctaw Facility of US Army Corps of Engineers mapping dated 2/13/1984.

Iberville Parish, Louisiana: Tracts 305 E-5, 319 E-1, 410 E-1, 410 E-3, 410 E-5, 427 E-1, 122 E-1, 120 E-1, 314 E-1, 315 E-1, 316 E-1, 316 E-3, 407 E-1, 425 E-1, 417 E-1, 428 E-1, 317 E-1, 317 E-3, 320 E-1, 400 E-1, 401 E-1, 401 E-3, 442E, 402 E-1, 403 E-1, 450 E-1, 443E, 444 E-1, 404 E-1, 430 E-1, 431E, 405 E-1, 408 E-1, 452L, 406 E-1, 451 E-1, 409 E-1, 411 E-1, 413 E-1, 414 E-1, 446 E-1, 447 E-1, 415 E-1, 416 E-1, 418 E-1, 424 E-1, 420 E-1, 426 E-1, 121 E-1, 421 E-1, 421 E-3, 423 E-1, 423E-3M 423 E-5, 440E, 441E, 429 E-1, 123 E-1, 123 E-3 as shown on Segment 1 of the Bayou Choctaw Facility of US Army Corps of Engineers mapping dated 11/5/1991, on Segment 3 of the Bayou Choctaw Facility of US Army Corps of Engineers mapping dated 2/13/1984 and on Segment 4 of the Bayou Choctaw Facility of US Army Corps of Engineers mapping dated 12/17/1980.

A-2.1.3.2 Pipeline Specification Data.

Table A-1. Pipeline Specification Data.

ANSI: 300# API-5LX-52 pipe
Wall Thickness: 0.312"
Operating Pressure
MAOP: 325 psi (hydrotest performed 1997)
Normal Operating Pressure: 210 psi
Installation Date: 1978
Last Smart Pig Inspection: 2013 (2018 completed, awaiting final report)

A-2.1.3.3 Valve Stations. Seven, 36-inch full bore slab gate valves.

A-2.1.3.4 Pipeline Connections and Requirements for Connecting. Current connections to the pipeline are at the Bayou Choctaw SPR site and the Tank Terminal, St. James, Louisiana. Whenever Lessee connects at any new tie-in locations, the following are requirements for Lessee:

A-2.1.3.4.1 Hot Tap or stopple, connection with Tee.

A-2.1.3.4.2 Isolation valve, double block and bleed.

A-2.1.3.4.3 Spectacle blind.

A-2.1.3.5 Cathodic Protection. Impressed Current

A-2.1.3.6 Maintenance Inspections

A-2.1.3.6.1 Procedures. Intelligent pigs (magnetic flux, ultrasonic and caliper) surveys have been used for corrosion detection and geometrical reductions. SPR pipeline operation is on an intermittent basis, thus pipeline wall is conducive to internal corrosion. Corrosion inhibiting chemicals and corrosion detection devices are periodically used to maintain and monitor pipeline integrity.

A-2.1.3.6.2 Inspection Summary. Based on 2013 Intelligent Pig Inspection, pipeline is certified to maintain the line at the current MAOP.

A-2.1.4 Pipeline Tie-In Descriptions

A-2.1.4.1 LOCAP 24 and Plains 36 Inch at Weeks Island Metering Station and LOCAP 30 to Discharge 2

A-2.1.4.1.1 LESSEE hereby agrees to the inclusion of the TIE-INs and LOCAP TRANSFER LINE as integral parts to the St. James Terminal Facility and their inclusion in the current lease of the ST. JAMES TERMINAL from GOVERNMENT.

A-2.1.4.1.2 LESSEE also agrees to operation and maintenance of the TIE-INs as well as the LOCAP TRANSFER LINE as part of the St. James Terminal Lease for the purpose of the movement of crude oil for receipts from and deliveries to the GOVERNMENT 36-inch Bayou Choctaw pipeline and for other movements between PLAINS, the ST. JAMES TERMINAL, and LOCAP. Should the DOT implement new or amend existing requirements for smart pigging or hydrotesting applicable to these new connections, the GOVERNMENT agrees to negotiate reasonable and customary compensation to LESSEE for performance and capital expenditures necessary to attain compliance. LESSEE shall be required to submit ECPs for GOVERNMENT approval of these capital and operational expenditures prior to execution.

A-2.1.4.1.3 LESSEE will, under separate agreement with LOCAP, negotiate in good faith toward commercial provisions for the movement of any crude oil which may include fees, scheduling, etc. LESSEE will not unreasonably withhold the movement of crude oil between any of the connecting parties.

A-2.1.4.1.4 LESSEE agrees to annual testing of the TIE-INs AND LOCAP TRANSFER LINE in all receipt and delivery, metered and direct modes unless proven to be functional by recent crude oil transfers between the ST. JAMES TERMINAL and PLAINS and/or LOCAP.

A-2.1.4.1.5 Connectivity to LOCAP / LOOP can be accomplished through either a 36 inch connection on the upstream side of its internal distribution or a 24 inch bi-directional connection inside.

A-2.1.4.2 LESSEE Shell 24 Inch Tie-In at Bayou Choctaw

A-2.1.4.2.1 LESSEE hereby agrees to the inclusion of the TIE-INs as integral parts to the St. James Terminal Facility and their inclusion in the current lease of the ST. JAMES TERMINAL from GOVERNMENT.

A-2.1.4.2.2 LESSEE also agrees to operation and maintenance of the TIE-INs as part of the St.

James Terminal Lease for the purpose of the GOVERNMENT crude oil movements.

A-2.1.4.2.3 LESSEE may, under separate agreement with Shell Pipeline Company and Placid, provide commercial crude oil movements on the Shell 24" pipeline.

A-2.1.4.2.4 LESSEE agrees to annual testing of the Tie-Ins.

A-2.1.4.3 CAPLINE 30 Inch Tie-in To St. James 30 inch Discharge 1 Header

A-2.1.4.3.1 LESSEE hereby agrees to the inclusion of the TIE-INs to Capline as an integral part of the St. James Terminal Facility and its inclusion in the current lease of the ST. JAMES TERMINAL from GOVERNMENT.

A-2.1.4.3.2 LESSEE also agrees to operation and maintenance of the TIE-INs to Capline as part of the St. James Terminal Lease for the purpose of the movement of crude oil for receipts from and deliveries to the GOVERNMENT 36-inch Bayou Choctaw pipeline and for other movements between PLAINS, the ST. JAMES TERMINAL, and LOCAP.

A-2.1.4.3.3 LESSEE will, under separate agreement with Capline, negotiate in good faith toward commercial provisions for the movement of any crude oil which may include fees, scheduling, etc. LESSEE will not unreasonably withhold the movement of crude oil between any of the connecting parties.

A-2.1.4.3.4 LESSEE agrees to annual testing of the TIE-INs in all receipt and delivery, metered and direct modes unless proven to be functional by recent crude oil transfers between the ST. JAMES TERMINAL and Capline.

A-2.1.4.4 Plains Marketing 36 Inch Pipeline Tie-In to St. James 20 inch piping - Accelerator pumps and to the Weeks Island Meter Station

A-2.1.4.4.1 LESSEE hereby agrees to the inclusion of the TIE-INs to the Plains 36 Inch pipeline as an integral part of the St. James Terminal Facility and its inclusion in the current lease of the ST. JAMES TERMINAL from GOVERNMENT.

A-2.1.4.4.2 LESSEE also agrees to operation and maintenance of the TIE-INs to the Plains 36 inch pipeline as part of the St. James Terminal Lease for the purpose of the movement of crude oil for receipts from and deliveries to the GOVERNMENT 36-inch Bayou Choctaw.

A-2.1.4.4.3 LESSEE will, under separate agreement with Plains, negotiate in good faith toward commercial provisions for the movement of any crude oil which may include fees, scheduling, etc. LESSEE will not unreasonably withhold the movement of crude oil between any of the connecting parties.

A-2.1.4.4.4 LESSEE agrees to annual testing of the TIE-INs.

A-2.1.4.5 Shell Pipeline Acadian River Terminal (ART) 36 Inch Two-Way Tie-In to Discharge 2 and Dock 2 line

A-2.1.4.5.1 LESSEE hereby agrees to the inclusion of the TIE-IN that leads to ART as an integral part of the St. James Terminal Facility and its inclusion in the current lease of the ST. JAMES TERMINAL from GOVERNMENT.

A-2.1.4.5.2 LESSEE also agrees to operation and maintenance of this TIE-IN to Shell Pipeline ART as part of the St. James Terminal Lease for the purpose of the movement of crude oil for receipts from and deliveries to the GOVERNMENT 36-inch Bayou Choctaw.

A-2.1.4.5.3 LESSEE will, under separate agreement with Shell Pipeline, negotiate in good faith toward commercial provisions for the movement of any crude oil which may include fees, scheduling, etc. LESSEE will not unreasonably withhold the movement of crude oil between any of the connecting parties.

A-2.1.4.5.4 LESSEE agrees to annual testing of the TIE-IN in all receipt and delivery, metered and direct modes unless proven to be functional by recent crude oil transfers between the ST. JAMES TERMINAL and Shell Pipeline.

A-2.1.4.6 Shell Pipeline ART and Capline Mainline 36 inch Tie-In to Discharge 1 and Dock 1 line

A-2.1.4.6.1 LESSEE hereby agrees to the inclusion of the TIE-IN at the fence line that leads to Capline Mainline and to the Shell ART 36 Inch as an integral part of the St. James Terminal Facility and its inclusion in the current lease of the ST. JAMES TERMINAL from GOVERNMENT.

A-2.1.4.6.2 LESSEE also agrees to operation and maintenance of the TIE-IN to Capline and Shell Pipeline ART as part of the St. James Terminal Lease for the purpose of the movement of crude oil for receipts from and deliveries to the GOVERNMENT 36-inch Bayou Choctaw.

A-2.1.4.6.3 LESSEE will, under separate agreement with Capline and Shell Pipeline, negotiate in good faith toward commercial provisions for the movement of any crude oil which may include fees, scheduling, etc. LESSEE will not unreasonably withhold the movement of crude oil between any of the connecting parties.

A-2.1.4.6.4 LESSEE agrees to annual testing of the TIE-IN in all receipt and delivery, metered and direct modes unless proven to be functional by recent crude oil transfers between the ST. JAMES TERMINAL and Capline and Shell Pipeline.

A-2.1.5 Environmental and Safety Systems

A-2.1.5.1 Fire Protection System. The tank terminal is equipped with a primary fire protection system using potable (City) water and a secondary or backup fire protection system using river water. The primary fire protection system is located at the main terminal and consists of a 400,000-gallon water tank, two 200 horsepower, 1,500-gallon-per-minute pumps (one electric and one diesel) and a 10 horsepower, 50-gallon-per-minute jockey pump. The secondary fire system is located on a platform next to Dock 1. The secondary fire system has two 10,000-gallon-per-minute pumps (one electric and one diesel).

A-2.1.5.2 Foam System. The tank terminal has 3 active foam deluge and proportioner systems located throughout the terminal.

A-2.1.5.3 Foam Retention Ponds. Two foam retention ponds have been constructed at the tank terminal to collect foam/water discharged by the fire control foam system.

A-2.1.5.4 Oil Spill Containment System. The tank terminal and the marine docks have an oil containment system, which collects any oil spilled during normal operations.

A-2.1.6 Utilities. Electrical power and potable water are supplied by outside providers. Sanitary waste disposal is on site.

A-2.1.6.1 Electric Power. The facility power requirements are currently supplied by Entergy Louisiana.

Primary feeders bring 34.5 kilovolts, 60-hertz electricity to an Entergy Louisiana substation located within the tank terminal in an area west of the Control Building. Substation transformers step down the power to a lower voltage prior to feeding the facility power distribution system. In addition to transformers, the substation contains fused disconnect switches, protective devices, and power meters.

A-2.1.6.2 Potable Water. Potable water is supplied to the facility from a St. James Parish water main. Water flows through a 4-inch line to a water meter and then to the Maintenance and Control Center/Office Buildings. Potable water is used for drinking fountains, urinals, lavatories, lunchroom, Maintenance/Shop building, showers, laboratory sinks, the first aid sink, and the primary firewater tank. Potable water is also supplied through a 2-inch line to each of the two marine docks.

A-2.1.6.3 Sanitary Waste Disposal. Liquid sanitary waste from the Administration, Contractor Office, Maintenance/Shop, and Crude Oil Laboratory Buildings (wash water and sewage) are collected in a sump and then pumped to a packaged chlorination unit for treatment.

A-3. FACILITY CONTROL SYSTEM

A-3.1 Process. The operations process control system at the St. James Terminal basically monitors and controls the six storage tanks, eight major pumps, associated valves, piping, and instruments both within the site and at the two loading/unloading docks on the Mississippi River. The current operations contractor uses Allen-Bradley ControlLogix PLCs and PLC-5 series I/O modules for control and monitoring at the terminal. An Allen-Bradley graphics program is used on the operator terminals in the site control room. It is the philosophy of the current operations controller to perform all equipment control remotely from an off-site location, but local control can be fully executed from the St. James control room if communications to the off-site location is unavailable. The operator terminals in the main control room are rack-mounted computers. All ladder-logic control programs within the PLCs and graphics programs used on the operator terminals are considered proprietary to the current operator. All ControlLogix and PLC-5 equipment was installed by the current operator. There are two metering stations on the site, each of which have three meter runs. Each meter run has a dedicated Moore flow computer, with one Omni flow computer for each meter taking the data from each of the Moore units for that skid and providing overall calculations for batch tickets, etc. The two (quantity) meter skids share a single prover loop.

A-3.2 Docks. There is a ControlLogix PLC at Dock 1 that provides control and monitoring for Docks 1 and 2. Each dock has a local operator terminal running the similar Allen-Bradley graphics program as on the main site which allows for local control from the dock.

A-3.3 Pipeline. All mainline pipeline valves on the St. James-to-Bayou Choctaw pipeline are manually controlled. There is no DCS control or status indication of any of the pipeline valves outside the St. James facility boundary.

A-3.4 Fire water system. Stand alone system with no interface to the Operations Process Controls.

A-3.5 Fire system. Stand alone system with no interface to Operations Process Controls.

A-3.6 Building Utilities. Stand alone system with no interface to Operations Process Controls.

A-4. FACILITY DRAWINGS AND DRAWING INDEX

A-4.1 Facility Drawings. Drawings that depict pipelines, tanks, docks, electrical systems, process piping, control system and facility layout are available. These drawings include pipeline map plans, piping and instrumentation drawings, loop diagrams, process flow diagrams, electrical one lines, functional block diagrams and area plans.

A-4.2 Drawing Index. A drawing index is available, at https://www.spr.doe.gov/doeec/Solicitation/facilitydrawings.htm, and is built using MS Excel with sorting on drawing index fields. The index includes drawing numbers, drawing type, descriptions, revision date, source of drawing, file name and notation on expected drawing accuracy.

Exhibit A-1
SPARE PARTS LIST

The following equipment is located in the warehouse at the terminal site in St. James and accounted for in the SPR Inventory System. LESSEE will be responsible for these items.

DESCRIPTION	QTY	TOTAL VALUE
COUPLING ASSEMBLY METAS:CPLR5000-IV-E430	2	$11,560
BELL,SUCTION BOTTOM SEC:78-2931-58	1	$7,863
BOWL,PUMP FOR BINGHAM W:28HXB2	1	$23,876
BOWL,PUMP FOR BINGHAM W:28HXB2	1	$23,876
GATE,VALVE,SLAB FOR 42":L41352	1	$5,917
GATE,VALVE,SLAB FOR 36":L41011	2	$9,912
ACTUATOR,VALVE LIMITORQUE:SMB000-293199	1	$2,181
PUMP,FIRE JOCKEY 1.5X1.5X 9:9946341741	1	$1,984
IMPELLER,PUMP 3-1/4"ID;:547303-1051	3	$2,751
ACTUATOR,VALVE EIM MODE:3701-016RPM	2	$7,418
METER,TURBINE 12" 150#:FT192CX1200LJC	1	$11,313
GATE,VALVE,SLAB FOR 36":L41011	1	$4,956
SEAT RING ASSEMBLY 42" 400 : 7-043964	2	$15,824
METER,TURBINE 12" 150#:FT192CX1200LJC	1	$11,313
TUBE,FLEX OUTER O-RING RUBBER:201-12008	1	$699
MOTOR,ACTUATOR 16A TYPE:16A21-5A	2	$1,806
GEARBOX ASSEMBLY F/LTV LOAD:4464-2904-07	1	$4,728
SPIDER,BEARING 3-1/4" I:V3238-62-056	7	$19,446
GATE,VALVE,SLAB FOR 30":L42325	4	$14,132
RING,SEAT APPL TO 30" 1:L42327	6	$9,000
GATE,VALVE,SLAB FOR 42":L41352	1	$5,917
GATE,VALVE,SLAB FOR 36":L41011	1	$4,956
GATE,VALVE,SLAB FOR 30":01700-30GATE	1	$5,100
GATE,VALVE,SLAB FOR 30":L42325	1	$3,533
SHAFT,PUMP 9 10" LG; TH:2626291-093	1	$515
SHAFT APPL TO JENSEN TA:680VAS12D2-39	2	$2,726
SHAFT,INTERMEDIATE 1"X5:460221706000-093	7	$756
SHAFT,PUMP 1"DIA; 8 LG;:2626323-093	1	$549
STEM,VALVE APPL TO 30" :D-124835-2	3	$4,563
STEM,VALVE APPL TO 24" :271241425	1	$3,300
SHAFT,TOP APPLIES TO PE:2615883-093	2	$652
SHAFT,LINE 1.00"X98", A:82361346	1	$210
SHAFT,PUMP 1-1/8" DIA I:104-207-9-2216	1	$276
SHAFT,PUMP 1-1/2" DIA; :7392TS1A093	1	$380
SHAFT,PUMP 1-1/2"DIA; 6:7392IS1A093	4	$720
SHAFT,PUMP 1-1/2"DIA; 6:7392B51A093	1	$180
SHAFT,PUMP 1-1/2"DIA; 4:7392-2TS1A093	1	$175
SHAFT,PUMP 1"X1 4 1/2";:V1000-03-093-1	1	$108
SHAFT,PUMP 2-11/16"DIA;:7392BS3A093	1	$310
SHAFT,PUMP 2-11/16"DIA;:7392LS3A093	1	$310
SHAFT,PUMP 3" DIA; 91" :7392-TS-3A-093	1	$1,468
SHAFT,PUMP 2-11/16" DIA:7392-2TS3A093	1	$385
SHAFT,PUMP 3-1/4" DIA; :5473212-102-5/8	1	$7,374
STEM,VALVE 90.375"LG; 3:L-41338	2	$4,054
STEM,VALVE APPLIES TO G:L42330	2	$3,672
STEM ASSEMBLY APPLY TO :D124836-2	1	$2,241
SHAFT,PUMP 3-1/4" DIA; :78-2931-65	1	$4,652
	GRAND TOTAL	**$249,637**

Exhibit A-2 Demarcation Responsibility (Lessee vs. Government) at the Bayou Choctaw Site Side of the Bayou Choctaw Pipeline.

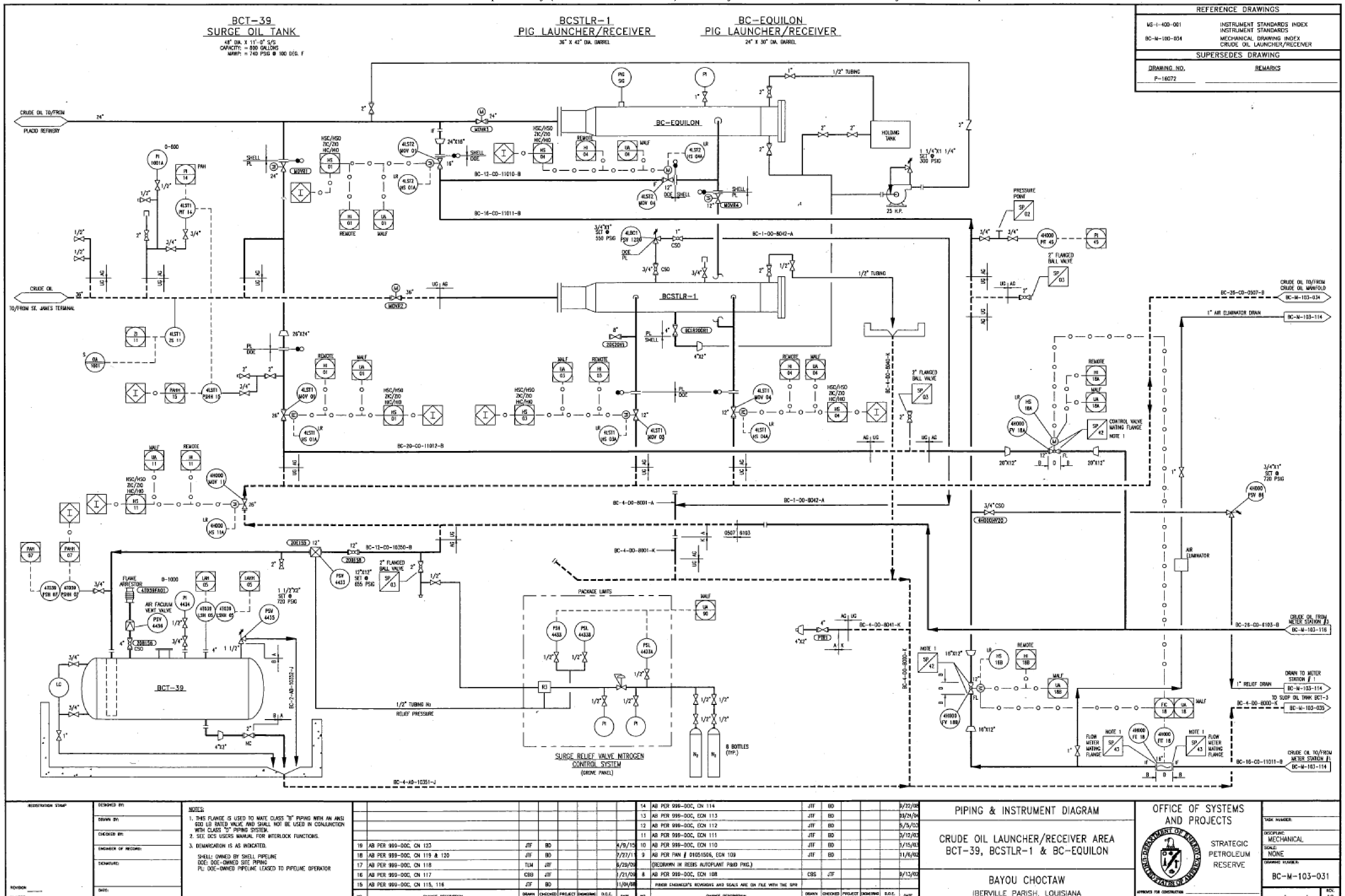

Exhibit A-3 Tagged Property Change Out Form

FFPO PROPERTY MANAGEMENT FORM
VERSION 10/2018

TAGGED PROPERTY CHANGE OUT FORM

NOTE: THIS FORM MUST BE COMPLETED EACH TIME TAGGED EQUIPMENT IS CHANGED OUT. THE PROPERTY TAG SHOULD BE REMOVED FROM THE EQUIPMENT AND AFFIXED TO THE BOTTOM OF THIS PAGE IN THE SPACE PROVIDED.

SEND COMPLETED FORM TO: FLUOR FEDERAL PETROLEUM OPERATIONS, LLC
ATTN: PROPERTY MANAGEMENT
521 ELMWOOD PARK BLVD.
NEW ORLEANS, LA 70123

NEW ITEM			
DESCRIPTION OF ITEM			
MANUFACTURER NAME			
MANUFACTURER SERIAL NUMBER			
MANUFACTURER MODEL			
MANUFACTURER PART NUMBER			
WEIGHT OF ITEM			
ACQUISITION VALUE			
YEAR ITEM WAS MANUFACTURED			
IS THERE A TRANSFERABLE WARRANTY			
SITE ITEM INSTALLED ON		DATE ITEM INSTALLED	

REMOVED ITEM			
DESCRIPTION OF ITEM			
GID TAG NUMBER			
MANUFACTURER			
MANUFACTURER SERIAL NUMBER			
MANUFACTURER MODEL NUMBER			
DATE ITEM WAS REMOVED		ITEM REMOVED FROM ONSITE WAREHOUSE INVENTORY	YES / NO (CIRCLE ONE)

FORM COMPLETED BY		REMOVE TAG AND PLACE HERE AFFIX TO PAGE USING TAPE			
RECEIVED BY FFPO					
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APPENDIX B - CONDITION OF FACILITY

B-1. GENERAL CONDITION.

Table B-1 below documents the condition of the facility as determined by EMPCo on October 1, 2019 based on prevois assessments, inspections and review of available facility documentation. This condition assessment is in review by the GOVERNMENT. Once the review is complete and all items dispositioned, the final condition assessmentlist will be memorialized in a contract modification to be dated January 1, 2020 or other agreed date.

Table B-1. EMPCo Findings of Facility Condition Assessment 20190930.

Concern ID#	Asset Category	Condition Description
1	Buildings	Building 701 water leaks; potentiat defective air conditioning/ducting and potential resulting inhalation/exposure hazards.
2	Docks	Missing wind speed alarm to alert the berth operator outside the building when winds reach limits to shut down the operation and disconnect the loading arms.
3	Docks	Existing level alarms may not satisfy DP XV-L and the definition of a SCD.
4	Docks	Unable to ascertain vessel accessibility due to absence of recent bathymetry surveys.
5	Docks	Dock Fire Monitors may not meet ISGOTT Section 19.5.3.8. requirements for remote operation. Need to reinstate remote operation (valve, position and stream control) of monitors to full function as part of terminal fire system refurbishment plan.
6	Docks	Dock Foam System may not meet ISGOTT Section 19.5.3.7 to provide 30 minutes of foam to two monitors at each berth.
7	Docks	Dock fire extinguishers may not meet ISGOTT Section 19.5.3.1 Table 19.1 requirements (berth handling ships 50,000 DWT and greater) to provide Docks 1 and 2 with wheeled dry chemical extinguishers.
8	Docks	Dock Fire Protection may not meet requirements of ISGOTT Sections 19.5.3.1, 19.5.3.2, and 19 5.3.3.
9	Docks	Gangways not provided from the docks. Depending on river stage level, ship's gangway may not provide safe access as required per ISGOTT Section 16.4.
10	Docks	Fire hydrants/stations on jetty approach way and berth may not be installed/spaced in accordance to ISGOTT Section 19 5.3.4.
11	Docks	Moderate corrosion at rubrail and splash zone pile on Docks 1 and 2 per the Facility Condition Assessment Report that was not addressed by prior operator; also unable to ascertain pile integrity.
12	Docks	Dock sump (loading area sump) appears to be potentially undersized and may not meet CFR requirements.

13	Facility	Facility Corrosion / Condition - Many of the nuts/bolts used throughout the facility appeared to be maintained poorly or uncoated resulting in rust build-up and staining of the flanges they are keeping together.
14	Facility	Facility Corrosion / Condition - Material Compatibility - numerous instances of stainless steel components (valves, nipples, plugs, etc.) used throughout the facility that are improperly connected to carbon steel components (nuts/bolts, flanges, blinds, etc.). This may be leading to galvanic corrosion of many carbon steel components
15	Facility	NPMS - Tanks, facility pipe, and/or dock lines are not registered as required in the National Pipeline Mapping System per 49 CFR 195.
16	Facility	Slop Oil - The catch basin discharges into a partially buried tank, which appears to be leaking on the sides.
17	Facility	Slop Oil Tank - Liquid is collecting in the T-202 Slop Oil / Drips Tank which is causing severe corrosion to the tank base. There is also a possible leak on the outlet piping.
18	Facility	Sump Tank - Liquid has collected in one of the sections on top of the Sump Tank. It appears that fragments of pipe fittings have broken off and are lying on the ground by the equipment.
19	Fire Suppression	Cooling water ring and supply piping on tanks appears original and not replaced as described in SPLC memo to DOE date 1/22/2019; Facility Condition Assessment Report (2016) mentions significant internal corrosion present on water supply pipings
20	Piping Interconnects	Evaluate condition of pipe to soil coating throughout the facility; repair with rock shield or some other type of pipe to soil coating as needed.
21	Piping Interconnects	42" line to Dock 1 OOS, serviced by 20" effluent line converted to crude oil service. 20" line with 12" valve may not satisfy requirement for 400 MBD readiness requirement in Lease Section 3.8.
22	Piping Interconnects	ESD / ESV - Emergency Shutdown Valves are missing between Facility and Docks 1 and 2.
23	Piping Interconnects	Permanent meters are not present on Docks 1 or 2.
24	Piping Interconnects	Potential soil contamination at Meter No.3 as evidenced by dried residue.
25	Piping Interconnects	Potential soil contamination at Meter No.1 as evidenced by dried residue.
26	Piping Interconnects	Unsupported pipe spans may not conform with ASME B31.4.
27	Piping Interconnects	Sump Vent heights may not meet NFPA 30 requirements.
28	Piping Interconnects	Surge analysis has not been provided for facility piping or dock lines; unable to assess suitablity of these lines to meet drawdown readiness requirements.

29	Piping Interconnects	Valve and soft goods specifications have not been provided; unable to assess for compatability with potentia crude slate.
30	Piping Interconnects	Valves may not all conform to API 6D and 49 CFR 195; insufficient information provided to assess.
31	Piping Interconnects	Potential soil contamination as evidenced by dried oil on valves T-320-DR5 and T-320-DR1 and there may have been a leak from the valve handles.
32	Prime Electrical	Potential arc flash hazard as Dock Control Room has 480 volt switch gear very close to the operator station.
33	Prime Electrical	Backup Emergency Generator (25kW) - Out of Service
34	Pumps	CP/Grounding several pumps throughout the facility are reported in Facility Assessment Condition Report as un-grounded.
35	RedStick Pipeline	36” mainline valves had their body drains removed and could lead to premature corrosion issues.
36	RedStick Pipeline	Potential soil contamination at mainline manual valve stations as evidenced by historical leaks and documented equipment conditions.
37	Site Civil	Several damaged or blocked culverts.
38	Site Civil	Helipad not in operational condition.
39	Site Civil	OWS water separators and weir box exhibit moderate to severe corrosion and are out of service.
40	Site Civil	Design capacity for and suitability of the waste water and effluent treatment systems cannot be ascertained as information has not been provided.
41	Site Civil	Potable / Sanitary / OWS - The weir box (SJT-WB1), oil water separators (SJT-SEP2A/B), and the retention pond (SJT-S2) are out of service.
42	Site Civil	Sink drain in the Sample Room appears improperly piped to the site waste water system.
43	Site Civil	Sanitary effluent pumps and treatment unit(s) may not be suitable for use and exhibit moderate to severe corrosion.
44	Site Civil	Piping to sanitary effluent pumps appears to have been removed or is out of service.
45	Tanks	Tank field impermeable liner information not provided; unable to ascertain if regulatory requirements are met.
46	Tanks	Lead abatement expected due to historical coatings on all tanks, piping, and equipment; copies of any historical asbestos, lead, and PCB surveys not provided.
47	Tanks	CP/Grounding - Cathodic protection and ground systems for tanks appears missing in some areas on multiple tanks.
48	Tanks	Tank EFR design on all tanks may not allow safe entry by staff nor gas-free operations for fire safety.

49	Tanks	EFR Roof drain design does not appear adequate and may result in unintended integrity and performance issues. Significant ponding (or consequential corrosion and integrity effects) seen on EFRS.
50	Tanks	Unable to ascertain Tank condition as current API 653 records provided do not consistently describe tank alteration or repairs performed.
51	Tanks	Potential soil contamination at tank mixers as evidenced by observed oil staining; mixers not provided with their own secondary containment.
52	Tanks	Potential soil contamination in storage tank area and equipment throughout facility due to historical leaks, spills, and documented equipment conditions.
53	Tanks	Tank 1 - Potential EFR Repair / Replacement may be required.
54	Tanks	Tank 1-- Primary / Secondary Seals may require replacement.
55	Tanks	Tank 2 - Potential floor replacement at next outage.
56	Tanks	Tank 2 - Potential soil contaminated - tank bottom had 36 through holes at 2014 outage
57	Tanks	Tank 2 - Potential EFR Repair / Replacement may be required.
58	Tanks	Tank 2 - Primary / Secondary Seals may require replacement.
59	Tanks	Tank 3 - Potential EFR repair and tank floor damage due to hard landings; significant repairs may be needed.
60	Tanks	Tank 3 - Primary / Secondary Seals may require replacement.
61	Tanks	Tank 3 - Significant floor repairs needed, may indicate potential for subfloor historical contamination
62	Tanks	Tank 4 - Potential soil contamination - tank bottom had 9 through holes at 2005 outage, 8 indications of product seepage at tank ringwall
63	Tanks	Tank 4 - Potential EFR repair and tank floor damage due to hard landings; significant repairs may be needed.
64	Tanks	Tank 5 - Potential EFR repair and tank floor damage due to hard landings; significant repairs may be needed.
65	Tanks	Tank 5 - Potential tank settlement and/or foundation damage may be present; may require repairs.
66	Tanks	Tank 6 - Potential EFR repair and tank floor damage due to hard landings; significant repairs may be needed.
67	Tanks	Tank 6 - Primary / Secondary Seals may require replacement.

APPENDIX C - PAYMENT CALCULATIONS

C-1. BAYOU CHOCTAW PIPELINE and St. James TANK TERMINAL AND DOCKS. The LESSEE shall pay rent monthly (see example below in C-1.7) to the GOVERNMENT based upon the prior month's actual throughput, per the following formula:

C-1.1 Minimum guaranteed monthly lease payment shall be:

C-1.1.1 Prior to initiation of LESSEE commercial operations - $0.

C-1.1.2 At initiation of LESSEE commercial operations - $166,666.67 / month ($2,000,000 / year).

C-1.2 Base Rental Fee – Is the rental fee beginning on the initiation of LESSEE commercial operations in the amount of $166,666.67 / month ($2,000,000 / year) through the lease term.

C-1.2.1 The Base Rental Fee will be adjusted per "PPI" (see C-1.8) by an amount equal to the change in the PPI as compared to the base period index. The change in the Base Rental Fee relative to $166,666.67 per month may be more or less in any lease year after the first (1st) lease year following the initiation of LESSEE commercial operations as calculated per this paragraph, but may not be decreased below $166,666.67 per month.

C-1.3 Additional Pipeline Rental Fee – Is the monthly calculation of the product of the total number of barrels of product transported from the Government's St. James Terminal to the Bayou Choctaw site and (b) (4) [redacted] with PPI adjustments, if any, plus the monthly calculation of the product of the total number of barrels of product transported from the Bayou Choctaw site to the Government's St. James Terminal and (b) (4) [redacted] with PPI adjustments, if any, less the monthly Base Rental Fee.

C-1.3.1 The Additional Pipeline Rental Fee will be adjusted per "PPI" by an amount equal to the change in the PPI as compared to the base period index. The change in the Base Rental Fee relative to (b) (4) [redacted] per month may be more or less in any lease year after the first (1st) lease year following the initiation of LESSEE commercial operations as calculated per this paragraph,but may not be decreased below (b) (4) [redacted] per month.

C-1.4 Additional Terminal Rental Fee – Is the monthly calculation of the product of the total number of barrels of product loaded onto barges or vessels through one of the Government's two St. James Docks and (b) (4) [redacted] with PPI adjustments, if any, plus the monthly calculation of the product of the total number of barrels of product off loaded from barges or vessels through one of the Government's two St. James Docks and (b) (4) [redacted] with PPI-FG adjustments, if any, less the monthly Base Rental Fee.

C-1.4.1 The Additional Terminal Rental Fee will be adjusted per "PPI" by an amount equal to the change in the PPI as compared to the base period index. The change in the Base Rental Fee relative to (b) (4) [redacted] per month may be more or less in any lease year after the first (1st) lease year following the initiation of LESSEE commercial operations as calculated per this paragraph, but may not be decreased below (b) (4) [redacted] per month.

C-1.5 Additional Pumpover Fee - Is the monthly calculation of the product of the total number of barrels through the facility from one pipe or terminal to another pipe or terminal through the St James facility excluding volumes utilizing Bayou Choctaw pipeline, the St James dock, or the planned interconnect to the SOLA 24" line, and (b) (4) [redacted] with PPI adjustments, if any, less the monthly Base Rental Fee.

C 1.5.1 Additional Pumpover Fee will be adjusted per "PPI" by an amount equal to the change in the PPI-FG as compared to the base period index. The change in the Base Pumpover Fee relative to [redacted] Fee may be more or less in any year after the first year of operation as calculated by this paragraph, but in no event less than [redacted].

C-1.6 With the initiation of LESSEE commercial operations and thereafter for the term of the Lease, and conditional to the subject pipeline and terminal maintaining commercial operation - the lease payment amount due will be the Base Rental Fee and the Additional Rental Fee, if any. This is determined by the equation that follows:

C-1.7 Monthly lease payment.

B_{RF} = Base Rental Fee

B_{RF} = [(Current Period PPI index) / (Base Period Index)] x \$166,666.67

PBP_{RF} = Per Barrel Pipeline Rental Fee

PBP_{RF} = [(Current Period PPI index) / (Base Period PPI Index)] x [redacted]

PBT_{RF} = Per Barrel Terminal Rental Fee

PBT_{RF} = [(Current Period PPI index) / (Base Period PPI Index)] x [redacted]

POF_{RF} = Per Barrel Pumpover Fee

POF_{RF} = [(Current Period PPI – FG index) / (Base Period PPI – FG Index)] x [redacted]

Additional fee for total number of barrels that cross the site tie-ins but do not use the Bayou Choctaw pipeline or terminal docks.

A_{RF} = Additional Rental Fee

A_{RF} = [(total bbls shipped on pipeline/month) x PBP_{RF}] + [(total bbls shipped across docks/month) x PBT_{RF}] + [(total bbls crossing site tie-ins /month) x POF_{RF}] – B_{RF}

Y = Monthly lease payment

$Y = B_{RF} + A_{RF}$

Example: During the base period, for a month in which: 1) 2,400,000 barrels moved on Bayou Choctaw Pipeline (80,000 bbls/d) and 2) 2,500,000 barrels moved across the dock terminal (5 ships in the month at 500,000 barrels each) and 3) 1,000,000 moved across St James in Pumpovers, the monthly payment owed to DOE would be:

1) BRF = Base Rental Payment of $166,666.67 Plus
2) ARF = Additional Rental Fee = (2,400,000 x [redacted]) + (2,500,000 x [redacted]) + (1,000,000 x [redacted]) - $166.666.67 = [redacted] + [redacted] + [redacted] – 166,666.67 = $[redacted]
3) Monthly Lease Payment = BRF + ARF = $166,666.67 + $[redacted] = $[redacted] for the example month

C-1.8 PPI – Annual Price Adjustment

C-1.8.4 All unit prices for services required by this contract shall be adjusted annually on May 1 of each year beginning in 2021. Unit price adjustments will be determined as follows:

$$\text{Adjusted Unit Price} = \sqrt{(\text{P-2}/\text{P-1}) \text{ X } (\text{L-2}/\text{L-1})} \quad \text{X} \quad \text{Base Level Price}$$

Where:

P-1 is the Electric Power in the Fuels & Related Products and Power Group as published in the "Producer Price Indexes" by the U.S. Department of Labor Statistics, for the month of January, 2020. (Series ID WPU054).

P-2 is the Electric Power in the Fuels & Related Products and Power Group as published in the "Producer Price Indexes" by the U.S. Department of Labor Statistics, for the month of January during the year in which the adjustment is made. (Series ID WPU054).

L-1 is the average Hourly Earnings in dollars of Production Workers in the Petroleum Refineries Industry, as published in the "current Employment Statistics Survey" by the Department of Labor, Bureau of Labor Statistics not seasonally adjusted for the month of January, 2020. (SERIES ID CEU3232400008).

L-2 is the average Hourly Earnings in dollars of Production Workers in the Petroleum Refineries Industry, as published in the "current Employment Statistics Survey" by the Department of Labor, Bureau of Labor Statistics not seasonally adjusted for the month of January during the year in which the adjustment is made. (SERIES ID CEU3232400008).

C-1.9 Payments shall be made within 25 days from the end of the month for which the payment is due.

C-1.10 Charges. When through-put charges apply, LESSEE published commercial tariff and standard Rules and Regulations shall apply, unless otherwise stated in this agreement. For GOVERNMENT oil movements, Schedule "A" will apply.

C-1.11 Payment. Payment is made by wire transfer, after receipt of invoice, on or before the 20th day of the month following the month of activity.

C-2. GOVERNMENT OIL EXERCISE PROVISIONS

C-2.1 National Energy Emergencies

C-2.1.1 In the event a National Energy Emergency is declared by the President that requires the GOVERNMENT to draw down the Strategic Petroleum Reserve (SPR), the GOVERNMENT would require oil to be moved through the Bayou Choctaw Pipeline (from Bayou Choctaw to the St. James Terminal) on a priority basis. The GOVERNMENT will coordinate and schedule national energy emergency oil movements with the LESSEE in accordance with GOVERNMENT drawdown procedures. The GOVERNMENT declares three alert levels, increasing in urgency, when drawdown of the SPR crude oil is expected. Under Alert Level I, the LESSEE will be requested to provide GOVERNMENT with information regarding the LESSEE's current pipeline activities. Under Alert Level II, the LESSEE will be notified that an SPR drawdown may be ordered and the LESSEE will be requested to update GOVERNMENT with information regarding the LESSEE's current pipeline activities. Under Alert Level III, the LESSEE will be notified that an SPR drawdown has been ordered and the LESSEE shall make the requisite pipeline facilities available to the SPR within (b) (4) [redacted] from the receipt of the written notice of impending drawdown.

C-2.1.2 During the period of Alert Level III, the LESSEE will continue to maintain the leased property in accordance with its Maintenance Plan and provide pipeline monitoring and repair services if required.

C-2.1.3 In less than a full rate drawdown, the GOVERNMENT will make the Bayou Choctaw pipeline and the St. James Storage Facility available to the LESSEE for commercial operations to the maximum extent possible.

C-2.2 Emergency Exchange and Operational Emergency Oil Movement

C-2.2.1 In the event of an operational emergency at the Strategic Petroleum Reserve, the LESSEE will make the leased Bayou Choctaw crude oil pipeline available to the Government, as soon as possible, after being notified by the Government. The LESSEE shall provide pipeline transportation services for GOVERNMENT crude oil to be moved through the leased property for the purposes of oil fill and oil withdrawal. In the event of an Emergency Exchange at the Strategic Petroleum Reserve, the LESSEE will make the leased Bayou Choctaw crude oil pipeline available to the Government, as soon as possible, after being notified by the Government.

C-2.2.1.1 Operational emergency oil movements and services will be subject to LESSEE's contract rates as described in Schedule A, which will remain in effect for the term of the Lease.

C-2.3 Non-Emergency Oil Movements

C-2.3.1 The LESSEE shall provide pipeline transportation services for GOVERNMENT crude oil to be moved through the leased property for the purposes of oil fill, oil withdrawal (oil sale) or system test exercises.

C-2.3.1.1 Oil fill or oil withdrawals will be coordinated and scheduled through provisions established for commercial oil movements. Oil fill, and oil withdrawal will be subject to LESSEE's contract rates as described in D-4 Schedule A, which will remain in effect for the term of the Lease.

C-2.3.1.2 SPR system test exercises may be conducted periodically (maximum of once per year) which may require the use of the Bayou Choctaw pipeline and St. James Storage Facility for a short period of time. All system test exercises will be coordinated between the GOVERNMENT and the LESSEE or pipeline operator, and will be scheduled so as to minimize interference with ongoing commercial operations. System test exercises will be subject to LESSEE's contract rates as described in Attachment "2", which will remain in effect for the term of the Lease.

C-2.3.2 LESSEE's standard Rules and Regulations as defined in its published tariffs will apply to all non-emergency oil movements.

APPENDIX D - OPERATIONAL PLAN FOR THE FACILITY

D-1. CRUDE OIL MOVEMENTS.

D-1.1 National Energy Emergency. Receive crude oil from Bayou Choctaw (SPR) site into LESSEE's facilities or to other third parties' facilities.

D-1.2 Emergency Exchange and Operational Emergency Oil Movement. Transportation and storage services as may be requested by GOVERNMENT or its customer and as may be available to be provided by LESSEE.

D-1.2.1 Oil Fill. Receive crude oil into LESSEE's facilities or from other third parties' facilities as directed by GOVERNMENT or its customer and deliver that same oil as directed by the GOVERNMENT or its customer to Bayou Choctaw (SPR). Note that due to the Bayou Choctaw site limitations, the oil receipt rate is limited to approximately 3,000 to 5,000 barrels per hour, dependent upon cavern availability. This may impact and delay the time that a Lessee may have access to the leased pipeline.

D-1.2.2 Oil Withdraw. Receive crude oil from Bayou Choctaw (SPR) site into LESSEE's facilities or to other third parties' facilities as directed by GOVERNMENT or its customer. St James has delivery capacity into pipeline of 620,000 barrels per day and into vessels through the dock of 400,000 barrels per day.

D-1.3 Non-Emergency Oil Movement.

D-1.3.1 Oil Fill. Receive crude oil into LESSEE's facilities or from other third parties' facilities as directed by GOVERNMENT or its customer and deliver that same oil as directed by the GOVERNMENT or its customer to Bayou Choctaw (SPR). Note that due to the Bayou Choctaw site limitations, the oil receipt rate is limited to approximately 3,000 to 5,000 barrels per hour, dependent upon cavern availability. This may impact and delay the time that a Lessee may have access to the leased pipeline.

D-1.3.2 Oil Withdraw. Receive crude oil from Bayou Choctaw (SPR) site into LESSEE's facilities and then to other third parties' facilities as directed by GOVERNMENT or its customer.

D-1.3.3 For fill movements into the SPR's Bayou Choctaw site, LESSEE will deliver crude oil in batch sizes of at least 40,000 barrels. Deliveries shall be at a minimum rate of at least 4,000 barrels per hour, over a 10-hour period. Smaller batch sizes are acceptable if the time between the batches GOVERNMENTs not exceed 24 hours. Note that due to the Bayou Choctaw site limitations, the oil receipt rate is limited to approximately 3,000 to 5,000 barrels per hour, dependent upon cavern availability. This may impact and delay the time that a Lessee may have access to the leased pipeline.

D-1.3.4 In the event that LESSEE uses pigs associated with deliveries into the Bayou Choctaw storage site, the pigs shall be launched at either the beginning, or the beginning and the end of the batch delivery. LESSEE pigs shall not arrive within a crude oil batch receipt at Bayou Choctaw.

D-1.3.5 During deliveries of crude oil by LESSEE into the Bayou Choctaw site, Lessee will allow government representatives or contracted inspectors onto the St. James Facility to witness the Lessee reference measurements for the oil being pushed into the Bayou Choctaw Pipeline. Lessee will also make copies of reference meter/tank measurements available to government representatives/inspectors."

D-1.4 Annual SPR test exercise. LESSEE will receive crude oil fromBayou Choctaw (SPR) into Bayou Choctaw Pipeline and deliver that crude oil to St. James Terminal location. Storage services if any is required will be covered under a separate agreement. The test exercise will be concluded when a like quantity of crude oil of same quality, or as may otherwise be directed by GOVERNMENT, is delivered back to GOVERNMENT at Bayou Choctaw (SPR) via Bayou Choctaw Pipeline.

D-1.4.1 National Energy Emergency Procedure.

D-1.4.1.1 During a national emergency wherein the GOVERNMENT is provided full use of the Bayou Choctaw pipeline for movement of SPR oil from the Bayou Choctaw site to St. James Terminal, the GOVERNMENT will become the shipper using both the BC measurement into the Bayou Choctaw Pipeline and St. James Terminal measurement leaving the Bayou Choctaw Pipeline. The GOVERNMENT will be the Shipper and incur all through-put charges into the St. James Facility tankage and pumped out to the Docks. Prior and/or separate contractual agreement would allow the GOVERNMENT to exchange or take ownership of the then current pipeline inventory if suitable displacement is not made available.

D-1.4.1.2 In the event the GOVERNMENT contracts with its customer to accept Bayou Choctaw measurement for primary custody while given full use of the Bayou Choctaw pipeline, the GOVERNMENT customer will be the shipper and responsible party for all charges pertaining to the Bayou Choctaw pipeline through-put. Any change of the custody measurement point from Bayou Choctaw meter to the St. James meter, the GOVERNMENT customer will remain responsible for all charges pertaining to the Bayou Choctaw pipeline through-put. Prior and/or separate contractual arrangement would allow the GOVERNMENT to exchange or take ownership of the then current pipeline inventory if suitable displacement is not made available.

D-1.4.2 Emergency Exchange and Operational Emergency Oil Movement.

D-1.4.2.1 During an Emergency Exchange or Operation Emergency, Bayou Choctaw measurement will be the primary custody point. If the GOVERNMENT assumes full use of the Bayou Choctaw pipeline, and assumes ownership of the Bayou Choctaw pipeline inventory, GOVERNMENT customer will be the shipper and responsible party for all charges pertaining to the Bayou Choctaw pipeline through-put. In the event of a required change of the custody measurement point from Bayou Choctaw meter to the St. James meter, the GOVERNMENT customer will remain responsible for all charges pertaining to the Bayou Choctaw pipeline through-put. Prior and/or separate contractual arrangement would allow the DOE to exchange or take ownership of the then current pipeline inventory if suitable displacement is not made available.

D-1.4.3 Non-emergency Oil Movement.

D-1.4.3.1 Delivery of crude oil into and out of the Bayou Choctaw site will use the BC meter and inline sampler for measurement. Delivery of crude oil into and out of the Bayou Choctaw pipeline will use the St. James meter and inline sampler. Non-emergency movements and (STEs) System test exercises will be subject to LESSEE's contract rates. Unless otherwise advised, the GOVERNMENT customer will be the shipper and responsible party for all charges pertaining to the Bayou Choctaw pipeline through-put.

D-2. CRUDE OIL QUALITY ASSURANCE.

LESSEE will only accept, crude oil consistent with merchantable crude for storage and transportation. LESSEE will not knowingly accept for storage and transportation crude oil, which GOVERNMENTs not comply with these requirements. LESSEE has no obligation to accept, store, or transport contaminated crude oil.

D-2.1 Contamination Guidelines. Contractor shall be liable for any nonhydrocarbon or non-merchantable liquid hydrocarbons, with contaminates such as additives, slops, organic chlorides, or waste caused by Contractor's gross negligence or willful misconduct. Should contaminated crude oil enter St. James Facility, LESSEE will be responsible for disposal and for all direct (excluding all consequential damages) damages and expenses incurred in returning St. James Facilities to service.

D-3. CRUDE OIL LOSSES.

D-3.1 Title for crude oil and risk of loss shall remain with crude oil owner. Customer is responsible for monthly pro-rated system losses in Bayou Choctaw Pipeline. The maximum allowable loss for the DOE for each pipeline and/or terminal through-put will be .20%. The GOVERNMENT will not incur losses of greater than .20% for each movement. Any gains to the GOVERNMENT may be used by the Lessee so as to offset losses within a one-month period for normal handling, transportation, line loss, storage, and shrinkage. Monthly pro-rated actual losses are determined by LESSEE, following month end closing which will occur at 7AM on the first day of each month. The monthly pro-rated actual losses are determined for Bayou Choctaw Pipeline by dividing the Customer's total delivered volume by the total volume delivered for all shippers and then multiplying this pro-rated percentage number by the total losses for Bayou Choctaw Pipeline. Pro-rated losses of less one quarter of one percent (¼ of 1%) will be reduced from Customers inventory volume. Customer may be required to supply additional inventory barrels to offset the crude oil losses assessed against Customers inventory. Line inventory and meters for Bayou Choctaw Pipeline located at Bayou Choctaw (SPR), St. James Terminal and other future meter locations will be utilized to determine monthly pipeline losses. LESSEE is responsible for losses, due to mismeasurement, above one quarter of one percent (1/4 of 1%). Net system gains will be retained by LESSEE. Crude oil losses are not automatic pipeline loss allowances charged against all barrels shipped.

D-3.2 Imbalances – Government and Lessee will work together to minimize imbalance barrels owed by one party to the other. Imbalances shall be repaid preferably in barrels to the owed party within 60 days of the last Government movement. To the extent such imbalances are greater than 1000 barrels and have been on the books for more than 60 days, the owing party shall pay the owed party in cash at an index price reflecting the value and quality of the crude the at the time the imbalance was created.

D-4. SCHEDULE A - CONTRACT UNIT PRICES

Item	Description	Unit	Unit Price
1.	**Emergency Exchange or Operational Emergency**		
a.	Bayou Choctaw site meter station measurement will be the primary custody point. When the GOVERNMENT is the shipper thereby assuming full use of the Bayou Choctaw pipeline, and assumes ownership of the Bayou Choctaw pipeline inventory, it will be to facilitate SPR movements of crude oil from the Bayou Choctaw site.	Dollars Per Day	Waiver of Lease Fee (b) (4) [redacted] (with annual PPI escalations)
b.	Tankage / Dock Loading	Cents Per Barrel	Government Crude (b) (4) [redacted] (with annual PPI escalation) (b) (4) [redacted] (with annual PPI escalation)
2.	**SYSTEM TESTING** - Crude Oil/Crude Petroleum movements from Bayou Choctaw site through Bayou Choctaw Pipeline and return to Bayou Choctaw site during system testing to include operational site maintenance transfers	Cents Per Barrel	(b) [redacted] For a maximum of one test per year not to exceed three days and twenty four hours of continuous pumping
3.	**Nonemergency drawdown/Commercial Sale**		
a.	Delivery of crude oil into and out of the Bayou Choctaw site will use the Bayou Choctaw meter and inline sampler for measurement. Delivery of crude oil into and out of the Bayou Choctaw pipeline will use the St. James Facility meter and inline sampler.	Cents Per Barrel	Then applicable FERC common carrier tariff rate
b.	Tankage / Dock Loading	Cents Per Barrel	Government Crude (b) (4) [redacted] (with annual PPI escalation) (b) (4) [redacted] (with annual PPI escalation)
4.	**National Emergency Drawdown**		
a.	During a national emergency wherein, the GOVERNMENT is given full use of the Bayou Choctaw pipeline for movement of SPR oil from the Bayou Choctaw site to St. James Facility, the GOVERNMENT will become the shipper using both the Bayou Choctaw site measurement into the Bayou Choctaw Pipeline and St. James Facility measurement leaving the Bayou Choctaw Pipeline.	Dollars Per Day	Waiver of Lease Fee (b) (4) [redacted] (with annual PPI escalations)
b.	Tankage / Dock Loading	Cents Per Barrel	Included
5.	**TANKAGE** – Storage of GOVERNMENT Crude Oil/Crude Petroleum due to emergency and nonemergency drawdown events.	Cents Per Barrel	(b) (4) [redacted] (with annual PPI escalation)

APPENDIX E - GOVERNMENT CRUDE OIL QUALITY AND QUANTITY

E-1. DETERMINATION OF QUANTITY AND QUALITY FOR GOVERNMENT MOVEMENTS.

E-1.1 All Government movements into and out of the St. James Facility will be inspected, witnessed and tested by the Government 3rd party inspector in accordance with the latest published version from the API Manual of Petroleum Measurement Standards, for Metering, Proving, and Shore-tank gauging. Meters and Provers will be the preferred measurement for quantity. Inline sampler will be the preferred method for quality. Customer will have the right to witness all measurement activities, including witness all Laboratory testing.

E-1.2 All measurement into and out of the Bayou Choctaw site will be based on Bayou Choctaw Meters (primary). Secondary measurement will be the St. James Meters.

E-1.3 All measurement into and out of St. James, (exiting the Bayou Choctaw pipeline) will be based on St. James Facility (primary). Secondary measurement will be the Bayou Choctaw site Meters.

E-1.4 All measurement into and out of St. James tank farm, including vessel loading, will be based on Meters (primary) and/shore-tank gauging (secondary) unless otherwise agreed to by parties.

E-1.5 Documentation of oil movements into or out of LESSEE's system will be by the applicable pipeline receipt/delivery ticket, tank gauge ticket, meter proving reports, and laboratory test report. Completed gauging and/or metering tickets and volume calculation worksheets will become supporting documents to the related Tanker/Barge loading and discharge reports (DD 250-1) or to the Material Inspection and Receiving Report (DD 250) for pipeline shipments or the Crude Oil Delivery Report (CODR) for drawdown or sale. (Refer to Attachment Nos. E-2, E-3, and E-4.)

E-1.5.1 Note: preliminary samples from the vessel's tanks and/or shore tanks will need to be tested (1-2 hours) for API Gravity, S&W (spin out), and NORM to assure compliance with SPR crude oil specifications prior to discharge. The GOVERNMENT 3rd party inspector will retrieve vessel samples upon arrival so as to expedite testing. Additionally, the vessel's tanks and/or shore tanks will need to be tested for contaminants prior to any receipts in Site caverns. Travel and testing can take between 6-8 hours to complete.

E-1.6 In case of measurement equipment failure, Parties will use best data available to determine the quantity and quality in question. Should a dispute arise concerning volume or other measurement issues, both parties hereto will make available during normal business hours their records concerning such dispute in an attempt to resolve such issues.

E-2. RESPONSIBILITY AND QUALITY/QUANTITY CONTROL FOR CRUDE OIL.

E-2.1 Determinable losses are defined as losses resulting from spills, pipeline breaks, mechanical failures, theft, fire and contamination. For the purpose of this contract, contamination of GOVERNMENT crude oil is defined in D-3.1while the oil is in the custody of the LESSEE.

Tables E-1. Quality Levels.

QUALITY	GOVERNMENT CRUDE OIL CATEGORY	
	SWEET	SOUR
Gravity - API°	+/-0.5	+/-0.5
Sulfur - Wt.%	+/-0.10	+/-0.10
Water and Sediment - (%Volume) Max	1.0	1.0

E-2.2 Operational Losses. The quantity of product deliverable at destination shall be the quantity received at origin, less shrinkage, evaporation, or other loss in transit, including leaks and breaks, resulting from any cause other than the sole negligence of Carrier, up to maximum loss of two-tenths of one percent (0.2 of 1%) of a Shipper's total movements hereunder during any calendar year.

E-2.3 Reimbursement for Crude Oil Losses. If the LESSEE is found liable for loss, destruction or contamination of GOVERNMENT crude oil under the provisions of the Government property clause (including all determinable losses, i.e., spills, contamination, destruction or theft, and for excess operational losses as defined below), the LESSEE shall pay the Government for the value of the oil lost, or for the loss in value of oil contaminated and downgraded to a lower type of SPR crude, as set forth below:

E-2.3.1 Determinable Losses

E-2.3.1.1 During Fill, Drawdown and System Testing. LESSEE shall pay the current market value to GOVERNMENT for the volumetric loss which has occurred.

E-2.3.1.2 The current market value is derived from the data published in the Platt's Oilgram Price Report and/or Argus price assessment. If no published prices are available, a mutually agreed upon price will be negotiated. Crude oil prices will be computed as follows:

E-2.3.1.2.1 Foreign crude oil, for SPR site receipt, will be based on current spot prices quoted as U.S. Gulf Coast (USGC) "outturn" barrels (cost of cargo, insurance, freight, lightering and all applicable taxes) against NYMEX WTI for delivery basis with additional cost to account for crudes moving from USGC to site.

E-2.3.1.2.2 Domestic crude oil grade, for SPR site receipt, will be based on spot prices quoted as a grade differential to the NYMEX WTI for delivery basis with additional cost to account for crudes moving from USGC to site.

E-2.3.1.2.3 SPR cavern oil will be based on spot prices as a comparable domestic benchmark crude (i.e., as of June 2018; Light Louisiana Sweet crude oil for Bryan Mound Sweet crude oil, Bonito sour crude oil for Bryan Mound sour crude oil) quoted against the NYMEX WTI for delivery basis which shall be the "Reference Price," with additional cost to account for crudes moving from USGC to site.

E-2.3.1.2.4 All above crude oil pricing computation methods shall be subject to a quality adjustment based on the difference in API gravity and total sulfur between the average of the reference crudes and the SPR crude oil lost (see Section E-3. Quality Adjustments).

E-2.3.2 Operational Losses

E-2.3.2.1 The LESSEE is liable for excess operational losses, as defined herein, and for determinable losses as defined herein, of GOVERNMENT crude oil occurring while in the LESSEE's possession, as specified in the limited risk of loss provisions of the Government Property Clause.

E-2.3.2.2 The LESSEE shall pay the Government for all excess operational quality losses based on the current reference price using the same formula as for system testing and for quality adjustments as defined above. The API gravity and total sulfur of the SPR crude as a basis for the quality adjustments will be the arithmetic average of all SPR crude oil handling during the 6-month period at the LESSEE's facility for which the loss is calculated.

E-2.3.3 Contamination Resulting in Downgrading to another SPR Crude Type

E-2.3.3.1 The LESSEE shall make payment to GOVERNMENT based on the actual changes in API gravity and total sulfur between the SPR oil received and the downgraded type returned at the rates shown under "Quality Adjustments" below.

E-3. QUALITY ADJUSTMENTS.

E-3.1 Quality adjustments for receipts of crude oil into the GOVERNMENT site shall be based on the differences between the quality test result of crude oil entering into the LESSEE's facility, or designated quality measurement point and the GOVERNMENT site destination test results which exceed those limits as set forth in section E-2.1 Table E-1.

E-3.2 Quality adjustments for crude oil deliveries out of the GOVERNMENT site shall be based on the differences between the GOVERNMENT site origin test results and the test results of the crude oil exiting the LESSEE's facility or designated quality measurement point which exceeds those limits as set forth in section E-2.1 Table E-1.

E-3.2.1 Quality differentials will be calculated by utilizing the API GravCap Table attached herein in Attachment E-5, Table E-5. The allowable variations from the common quality for crude oil deliveries are as defined in section E-2.1 Table E-1.

E-3.2.2 API Gravity between 40.0 and 45.0: No quality differential shall be accessed.

E-3.2.3 API Gravity between 35.0 and 40.0: Adjustment for Sweet/Sour crude oil is 2¢ per barrel for each degree (1.0°) increase/decrease in (API) Gravity, or part thereof, by which the allowable variation set forth above is exceeded. Specifically, computed API Gravity excess variances for each cargo, reported in API Gravity 0.1° increments, shall be rounded up to the next whole 1.0° API.

E-3.2.4 API Gravity below 35.0: Adjustment for Sweet/Sour crude oil is 1.5¢ per barrel for each tenth of a degree (0.1°) increase/decrease in (API) Gravity, or part thereof, by which the allowable variation set forth above is exceeded.

E-3.2.5 Total Sulfur: 1.0¢ per barrel for each 1/100th percent (0.01%) increase/decrease in total sulfur by which the allowable variations set forth above are exceed.

E-3.2.6 If crude oil delivered to the GOVERNMENT falls below the minimum SPR specification for API Gravity, or above the maximum GOVERNMENT specification for sulfur, as defined in Attachment E-1, Table E-4, a quality differential adjustment shall be applied without a variance allowance on that portion exceeding the specification limit.

E-4. PROPERTY CONTROL RECORDS AND REPORTS.

E-4.1 DD Form 250-1, Tanker/Barge Loading and Discharge Report (refer to Attachment E-3-) shall be used to document all tanker/barge loadings and discharges and shall be signed by the Government Third-Party Inspector. DD Form 250, Material Inspection and Receiving Report (refer to Attachment E-2) shall be used to document all pipeline deliveries and receipts and shall be signed by the Government Third-Party Inspector. These reports shall be supported by appropriate tanker/ barge ullage reports and shore tank gauging or meter tickets (as applicable), calculation worksheets and laboratory analyses reports.

E-4.2 During drawdown, all deliveries to purchasers, whether by pipeline or to vessels, will be documented on Form SPRPMO F-416.1-3, Strategic Petroleum Reserve Crude Oil Delivery Report (CODR) (refer to Attachment E-4) which shall require signatures of the purchaser or designee, the terminal representative, the purchaser's agent, and the vessel's master (if appropriate). The CODR will be supported by the appropriate shore tank gauging or meter tickets (as applicable), calculation worksheets, and laboratory analyses reports.

E-5. NETOUTS.

E-5.1 If Lessee has been requested by the Government to deliver Crude Oil for the Government for any purpose including tests, Lessee may upon mutual agreement make delivery from the shipments of other shipper's Crude Oil provided that the Crude Oil to be delivered meets Government's specifications and is acceptable by the Government. In such event, any quality differences shall be corrected through a monetary adjustment, indexed on current GravCap tables (attachment E-5 GravCap Table API and GravCap Table Sulfur, current as of Oct 2018), as payment to the Government or to Lessee (for the account of Lessee's other shipper(s)) depending on which Party has the net better quality crude by being higher API gravity or lower total sulfur content. Laboratory tests for API Gravity and Sulfur Weight Percent shall be taken both when custody of the Crude Oil is originally passed to the Lessee and when custody of the Crude Oil is returned to the Government or transferred at Government's request to another shipper or carrier. The quality differentials shall be based on the resulting analysis differences between these tests and calculated using the following adjustment factors:

Table E-2. Quality Differential Adjustment Factors.

Quality Characteristics	SPR Crude Oil Quality	Variation Limits
	Sour	Sweet
Gravity – API°	+/- 0.5	+/- 0.5
Sulfur – WT,%	+/- 0.10	+/- 0.10

E-5.2 Where applicable, the quality adjustments shall have rates adjusted per the following methodology which is also shown on attachment E-5 GravCap Table API and GravCap Table Sulfur:

E-5.2.1 API Gravity. Sour Crude Oil (Sulfur weight % greater than 0.5%), 1.5 cents per barrel for each 1/10th degree (0.1) excess variance (+/-) in gravity when the limits set forth above are exceed.

E-5.2.2 Sweet Crude Oil (Sulfur weight % less than or equal to 0.5%), 2 cents per barrel for each whole degree (1.0) API Gravity, or part thereof, when the limits set forth above are exceeded.

E-5.2.3 Total Sulfur. 1.0 cents per barrel for each 1/100th percent (0.01%) increase in total sulfur when the limits set forth above are exceeded. See attachment E-5 GravCap Table Sulfur.

E-5.2.3.1 API Gravity. If the Government delivers Crude Oil of a lower gravity than that received, then any such adjustment shall represent a payment to the Lessee for the account of Lessee's other shipper(s).

E-5.2.3.2 Total Sulfur. If the Government delivers Crude Oil of a lower sulfur than that received, then any such adjustment shall represent a payment to the Government, otherwise any such adjustment shall represent a payment to the Lessee for the account of Lessee's other shipper(s).

E-5.2.3.3 Payment due from A) and/or B) shall be netted together and result in a single payment from the Party net owing. Such payment shall be due from the Government within thirty (30) days of receipt of a valid invoice, or from Lessee within ten (10) days of receipt of payment from Lessee's other shipper(s). Lessee shall arrange for the sampling and testing required to implement this provision. A Government contracted third party inspector shall witness all sampling and testing analysis. Government shall provide access at its facilities to Lessee for the purpose of collecting any such samples.

TABLE E-3. GravCap Example Quality Adjustment.

EXAMPLE: Quality Adjustment	SOUR CRUDE	SWEET CRUDE
API Gravity - SPR delivered bbls	35.8°	35.8°
API Gravity - Lessee returned bbls	38.2°	38.0°
API Gravity - Quality Variance	2.4°	2.2°
Allowable Variance	±0.5°	±0.5°
Excess Variance - API Gravity	1.9°	1.7°
API Gravity $ Adjustment per bbl	- 28.5¢	- 4¢
"- ¢" = SPR owes Lessee		
"+ ¢" = Lessee owes SPR		
Sulfur Wt% - SPR delivered bbls	1.33%	0.33%
Sulfur Wt% - Lessee returned bbls	1.46%	0.39%
Sulfur Wt% - Quality Variance	0.13%	0.06%
Allowable Variance	±0.10%	±0.05 %
Excess Variance - Sulfur Wt%	0.03%	0.01%
Sulfur Wt% $ Adjustment per bbl	+3¢	+1¢
"- ¢" = SPR owes Lessee		
"+ ¢" = Lessee owes SPR		
Net Quality $ Adjustment per bbl	- 25.5¢	- 3¢
"- ¢" = SPR owes Lessee		
"+ ¢" = Lessee owes SPR		

ATTACHMENT E-1

TABLE E-4. STRATEGIC PETROLEUM RESERVE CRUDE OIL SPECIFICATIONS [a] (SPRO JULY 2015) [ε1]

CHARACTERISTIC	SOUR	SWEET	PRIMARY ASTM TEST METHOD [b]
API Gravity [°API]	30-45	30-45	D 1298 or D 5002
Total Sulfur [Mass %], max.	1.99	0.50	D 4294
Pour Point [°C], max.	10	10	D 97
Salt Content [Mass %], max.	0.050	0.050	D 6470
Viscosity			
[cSt @ 15.6°C], max.	32	32	D 445
[cSt @ 37.8°C], max.	13	13	
Reid Vapor Pressure [kPa @ 37.8°C], max.	76	76	D 323 or D 5191
Total Acid Number [mg KOH/g], max.	1.00	1.00	D 664
Water and Sediment [Vol. %], max.	1.0	1.0	D 473 and D 4006, or D 4928
Yields [Vol. %]			D 2892 and D 5236[c]
Naphtha [28-191°C]	24-30	21-42	
Distillate [191-327°C]	17-31	19-45	
Gas Oil [327-566°C]	26-38	20-42	
Residuum [>566°C]	10-19	14 max.	
Light Ends [Liquid Vol. %] [d], max			
Methane (C_1)	0.01	0.01	IP 344 or ITM 6008
Ethane (C_2)	0.1	0.1	
Propane (C_3)	1.0	1.0	

ε1 This revision includes a limitation on light ends content (see Footnote [d])

a Marketable crude petroleum suitable for normal refinery processing and free of foreign contaminants or chemicals including, but not limited to, pour point depressants, chlorinated and oxygenated hydrocarbons, and lead.

b Alternate methods may be used if approved by the contracting officer.

c D 7169 data may be provided in requesting conditional acceptance of a crude oil. Distillation data according to D 2892 and D 5236 will still be necessary for final qualification of a crude oil's acceptance.

d Light ends content specifications are interim and will be superseded if and when industry standards for light ends evaluation are implemented.

NOTE 1: The Strategic Petroleum Reserve reserves the right to refuse to accept any crude oil which meets these specifications but is deemed to be incompatible with existing stocks, or which has the potential for adversely affecting handling.

NOTE 2: The acceptability of any crude oil depends upon any assay typical of current production quality of the stream. Assays typical of current production quality are mandatory for any crude oil not received by the SPR within the last three years. Any crude oil offered to the Strategic Petroleum Reserve that meets these specifications may be subject to additional testing for acceptance.

NOTE 3: All crude oil shipments received by the SPR are tested to ensure they meet specifications. Crude streams found consistently not meeting required specifications will be removed from the list of acceptable crude oils.

ATTACHMENT E-2
DD FORM 250
MATERIAL INSPECTION AND RECEIVING REPORT

MATERIAL INSPECTION AND RECEIVING REPORT

Form Approved
OMB No. 0704-0248

Public reporting burden for this collection of information is estimated to average 30 minutes per response, including the time for reviewing instruc ions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing the collection of information. Send comments regarding his burden estimate or any other aspect of this collection of information, including suggestions for reducing this burden, to Department of Defense, Washington Headquarters Services, Directorate for Information Operations and Reports (0704-0248), 1215 Jefferson Davis Highway, Suite 1204, Arlington, VA 22202-4302, and to he Office of Management and Budget, Paperwork Reduc ion Project (0704-0248), Washington, DC 20503. Respondents should be aware that notwithstanding any o her provision of law, no person shall be subject to any penalty for failing to comply with a collection of information if it GOVERNMENTs not display a currently valid OMB control number.

PLEASE DO NOT RETURN YOUR COMPLETED FORM TO EITHER OF THESE ADDRESSES.
SEND THIS FORM IN ACCORDANCE WITH THE INSTRUCTIONS CONTAINED IN THE DFARS, APPENDIX F-401.

1. PROCUREMENT NSTRUMENT DENT FICATION. (CONTRACT) NO.	(ORDER) NO.	6. INVOICE NO /DATE	7. PAGE OF	8. ACCEPTANCE PO NT
2. SH PMENT NO.	3. DATE SHIPPED	4. B/L TCN	5. DISCOUNT TERMS	
9. PR ME CONTRACTOR *CODE*		10. ADM NISTERED BY *CODE*		
11. SH PPED FROM (if other than 9) *CODE* FOB:		12. PAYMENT WILL BE MADE BY *CODE*		
13. SHIPPED TO CODE		14. MARKED FOR *CODE*		

15. ITEM NO.	16. STOCK/PART NO. DESCRIPTION *(Indicate number of shipping containers - type of container - container number.)*	17. QUANTITY SHIP / REC'D *	18. UNIT	19. UNIT PRICE	20. AMOUNT
		.			

21. CONTRACT QUALITY ASSURANCE

A. ORIGIN

☐ CQA ☐ ACCEPTANCE of listed items has been made by me or under my supervision and they conform to contract, except as noted herein or on supporting documents.

_ DATE SIGNATURE OF AUTHORIZED GOVERNMENT REPRESENTATIVE

TYPED NAME
TITLE:
MAILING ADDRESS:

COMMERCIAL TELEPHONE NUMBER:

B. DESTINATION

☐ CQA ☐ ACCEPTANCE of listed items has been made by me or under my supervision and they conform to contract, except as noted herein or on supporting documents.

_ DATE SIGNATURE OF AUTHORIZED GOVERNMENT REPRESENTATIVE

TYPED NAME
TITLE:
MAILING ADDRESS:

COMMERCIAL TELEPHONE NUMBER:

22. RECEIVER'S USE

Quantities shown in column 17 were received in apparent good condition except as noted.

DATE RECEIVED SIGNATURE OF AUTHORIZED GOVERNMENT REPRESENTATIVE

TYPED NAME:
TITLE:
MAILING ADDRESS:

COMMERCIAL TELEPHONE NUMBER:

** If quantity received by the Government is the same, as quantity shipped, indicate by (x) mark; if different, enter actual quantity received below quantity shipped and encircle.*

23. CONTRACTOR USE ONLY

DD Form 250, AUG 2000

TANK/BARGE MATERIAL INSPECTION AND RECEIVING REPORT

FORM APPROVED
OMB No. 0704-0248
Expires Dec 31, 1990

Public reporting burden for this collection of information is estimated to average 35 minutes per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing the collection of information. Send comments regarding this burden estimate or any other aspect of this collection of information, including suggestions for reducing this burden, to Washington Headquarters Services, Directorate for Information Operations and Reports, 1215 Jefferson Davis Highway, Suite 1204, Arlington, VA 22202-4302, and to the Office of Management and Budget, Paperwork Reduction Project (0704-0248), Washington, DC 20503.

PLEASE DO NOT RETURN YOUR COMPLETED FORM TO EITHER OF THESE ADDRESSES.
SEND THIS FORM IN ACCORDANCE WITH THE INSTRUCTIONS CONTAINED IN THE DFARS, APPENDIX F-401.

1. TANKER BARGE
☐ LOADING REPORT ☒ DISCHARGE REPORT

2. INSPECTION OFFICE

3. REPORT NUMBER

4. AGENCY PLACING ORDER ON SHIPPER, CITY, STATE AND/OR LOCAL ADDRESS *(Loading)*

5. DEPARTMENT

6. PRIME CONTRACT OR P.O. NUMBER

7. NAME OF PRIME CONTRACTOR, CITY, STATE AND/OR LOCAL ADDRESS *(Loading)*

8. STORAGE CONTRACT

9. TERMINAL OR REFINERY SHIPPED FROM, CITY, STATE AND/OR LOCAL ADDRESS *(Loading)*

10. ORDER NUMBER OR SUPPLIER

11 SHIPPED TO *(Receiving, Activity, City, State and/or Local Address)*

12. B/L NUMBER

13. REQN. OR REQUEST NO.

14. CARGO NUMBER

15. VESSEL

16. DRAFT ARRIVAL
FORE AFT

17. DRAFT SAILING
FORE AFT

18. PREVIOUS TWO CARGOES
FIRST LAST

19. PRIOR INSPECTION

20. CONDITION OF SHORE PIPELINE

21. APPROPRIATION *(Loading)*

22. CONTRACT ITEM NO.
N/A

23. PRODUCT

24. SPECIFICATIONS
N/A

25. STATEMENT OF QUANTITY	LOADED	DISCHARGED	LOSS/GAIN	PER CENT
BARRELS *(42 Gals/Net)* NSV				
GALLONS *(Net)*				
Barrels GSV				

26. STATEMENT OF QUALITY

TEST RESULTS		VESSEL COMPOSITE	TEST RESULTS	THIRD PARTY INSPECTOR VESSEL COMPOSITE
API GRAVITY				
WATER & SEDIMENT				
TOTAL SULFUR				

27. TIME STATEMENT	DATE	TIME
NOTICE OF READINESS TO LOAD DISCHARGE		
VESSEL ARRIVED IN ROADS		
MOORED ALONGSIDE		
STARTED BALLAST DISCHARGE		
FINISHED BALLAST DISCHARGE		
INSPECTED AND READY TO LOAD DISCHARGE		
CARGO HOSES CONNECTED		
COMMENCED LOADING DISCHARGE		
STOPPED LOADING DISCHARGING		
RESUMED LOADING DISCHARGING		
FINISHED LOADING DISCHARGING		
CARGO HOSES REMOVED		
VESSEL RELEASED BY INSPECTOR		
COMMENCED BUNKERING		
FINISHED BUNKERING		
VESSEL LEFT BIRTH *(Actual/Estimated)*		

28. REMARKS *(Note in detail cause of delays such as repairs, breakdowns, slow operations, stoppage, etc.)*

29. COMPANY OR RECEIVING TERMINAL

(Signature)

30. I CERTIFY THAT THE CARGO WAS INSPECTED, ACCEPTED AND LOADED/ DISCHARGED AS INDICATED HEREON.

(Date) *(Signature of Authorized Government Representative)*

31. I HEREBY CERTIFY THAT THIS TIME STATEMENT IS CORRECT.

(Master or Agent)

DD Form 250-1, NOV 92 (EG) *Previous edition may be used* Designed using Perform Pro, WHS/DIOR, Mar 97

ATTACHMENT E-4
SPRPMO FORM 434.1-1B-3
STRATEGIC PETROLEUM RESERVE CRUDE OIL DELIVERY REPORT

STRATEGIC PETROLEUM RESERVE CRUDE OIL DELIVERY REPORT

1. SALES CONTRACT NUMBER	2. TERMINAL REPORT NUMBER	3. CARGO NUMBER	
4. DATE DELIVERED	5. TRANSPORTATION MODE ☐ TANKER ☐ BARGE ☐ PIPELINE	6. ACCEPTANCE POINT ☐ ORIGIN ☐ DESTINATION	7. PRICE DATE
8. SHIPPING SPR SITE/TERMINAL	9. PURCHASER-NAME AND ADDRESS	10. CARRIER	

11. CONTRACT LINE ITEM MLI	DLI	12. DESCRIPTION OF CRUDE OIL AND GROSS BBLS	13. API GRAVITY	14. TOTAL SULPHUR %	15. DEL'D NET BBLS @ 60° F	16. UNIT PRICE	17. AMOUNT DUE
18. QUALITY ADJUSTMENT - INCREASE/(DECREASE) 18A. NET API GRAVITY/SULFUR ADJUSTMENT FROM 18B/C (4) ________							

18B. CALCULATION OF API GRAVITY ADJUSTMENT		18C. CALCULATION OF SULFUR MASS % ADJUSTMENT	
(1) ADVERTISED API GRAVITY		(1) ADVERTISED SULFUR %	
(2) ALLOWED API GRAVITY (+/- 0.5°)		(2) ALLOWED SULFUR (+/- 0.10%)	
(3) DELIVERED API GRAVITY		(3) DELIVERED SULFUR %	
(4) API GRAVITY ADJUSTMENT $/BBL.		(4) SULFUR ADJUSTMENT $/BBL.	
Qlty. Table Computation Basis: Line (3) - Line (2)		Qlty. Table Computation Basis: Line (2) - Line (3)	

21. TIME STATEMENT	DATE	TIME
NOTICE OF READINESS TO LOAD		
VESSEL ARRIVED IN ROADS		
PILOT ON BOARD		
WEIGHED ANCHOR		
FIRST LINE ASHORE		
MOORED ALONGSIDE		
STARTED BALLAST DISCHARGE		
FINISHED BALLAST DISCHARGE		
INSPECTED AND READY TO LOAD		
CARGO HOSES CONNECTED		
COMMENCED LOADING		
STOPPED LOADING		
RESUMED LOADING		
FINISHED LOADING		
CARGO HOSES REMOVED		
VESSEL RELEASED BY INSPECTOR		
COMMENCED BUNKERING		
FINISHED BUNKERING		
VESSEL LEFT BERTH (ACTUAL OR ESTIMATED)		

19. CONTRACT MOD ADJUSTMENT	
20. NET AMOUNT DUE	

22. THE DELIVERED NET BARRELS, UNIT PRICE, PRICE DATE, QUALTIY ADJUSTMENT AND CONTRACT MOD ADJUSTMENT DUE HAVE BEEN VERIFIED.

SIGNATURE: ______________________________

ACCOUNTABLE OFFICER

23. REMARKS

24. GOVERNMENT INSPECTOR'S CERTIFICATE:

I HEREBY CERTIFY THAT THE (VESSEL CARGO) (PIPELINE SHIPMENT) WAS INSPECTED, DELIVERED AND ACCEPTED AS SHOWN HEREON.

DATE ____________ SIGNATURE ______________________

NAME TYPED/PRINTED

25. RECEIPT IS ACKNOWLEDGED FOR THE QUANTITY AND QUALITY SHOWN HEREON:

DATE RECEIVED: ______________________

AGENT: ______________________

BY: ______________________

NAME/PRINTED

26. I CERTIFY THAT THE TIME STATEMENT SHOWN HEREON IS CORRECT.

SIGNATURE ______________________

MASTER OF VESSEL

SPRPMO F-416.1-3 (Rev. 10/10)

ATTACHMENT E-5
GRAVCAP TABLE API.

GRAVCAP, INC.
ADJUSTMENT AUTHORIZATION

TABLES OF DIFFERENTIALS FOR USE IN DETERMINING ADJUSTMENTS FOR
DIFFERENCE IN GRAVITY OF CRUDE PETROLEUM

WHITE CAP SYSTEM - BONITO PIPE LINE COMPANY - SHIP SHOAL SYSTEM - CAPLINE SYSTEM

API GRAVITY	DIFF. PER BBL	API GRAVITY	DIFF. PER BBL	API GRAVITY	DIFF. PER BBL	API GRAVITY	DIFF. PER BBL	API GRAVITY	DIFF. PER BBL	API GRAVITY	DIFF. PER BBL	API GRAVITY	DIFF. PER BBL	API GRAVITY	DIFF. PER BBL
10.0	1.250	16.0	2.150	22.0	3.050	28.0	3.950	34.0	4.850	40.0	5.100	46.0	4.950	52.0	4.050
10.1	1.265	16.1	2.165	22.1	3.065	28.1	3.965	34.1	4.865	40.1	5.100	46.1	4.935	52.1	4.035
10.2	1.280	16.2	2.180	22.2	3.080	28.2	3.980	34.2	4.880	40 2	5.100	46.2	4.920	52.2	4.020
10.3	1.295	16.3	2.195	22.3	3.095	28.3	3.995	34.3	4.895	40 3	5.100	46.3	4.905	52.3	4.005
10.4	1.310	16.4	2.210	22.4	3.110	28.4	4.010	34.4	4.910	40.4	5.100	46.4	4.890	52.4	3.990
10.5	1.325	16.5	2.225	22.5	3.125	28.5	4.025	34.5	4.925	40 5	5.100	46.5	4.875	52.5	3.975
10.6	1.340	16.6	2.240	22.6	3.140	28.6	4.040	34.6	4.940	40.6	5.100	46.6	4.860	52.6	3 960
10.7	1.355	16.7	2.255	22.7	3.155	28.7	4.055	34.7	4.955	40.7	5.100	46.7	4.845	52.7	3 945
10.8	1.370	16.8	2.270	22.8	3.170	28.8	4.070	34.8	4.970	40.8	5.100	46.8	4.830	52.8	3 930
10.9	1.385	16.9	2.285	22 9	3.185	28.9	4.085	34.9	4.985	40 9	5.100	46.9	4.815	52.9	3 915
11.0	1.400	17.0	2.300	23.0	3.200	29.0	4.100	35.0	5.000	41.0	5.100	47.0	4.800	53.0	3 900
11.1	1.415	17.1	2.315	23.1	3.215	29.1	4.115	35.1	5.000	41.1	5.100	47.1	4.785	53.1	3.885
11.2	1.430	17.2	2.330	23 2	3.230	29.2	4.130	35.2	5.000	41 2	5.100	47.2	4.770	53.2	3.870
11.3	1.445	17.3	2.345	23 3	3.245	29.3	4.145	35.3	5.000	41 3	5.100	47.3	4.755	53.3	3.855
11.4	1.460	17.4	2.360	23.4	3.260	29.4	4.160	35.4	5.000	41.4	5.100	47.4	4.740	53.4	3.840
11.5	1.475	17.5	2.375	23 5	3.275	29.5	4.175	35.5	5.000	41 5	5.100	47.5	4.725	53.5	3.825
11.6	1.490	17.6	2.390	23.6	3.290	29.6	4.190	35.6	5.000	41.6	5.100	47.6	4.710	53.6	3.810
11.7	1.505	17.7	2.405	23.7	3.305	29.7	4.205	35.7	5.000	41.7	5.100	47.7	4.695	53.7	3.795
11.8	1.520	17.8	2.420	23.8	3.320	29.8	4.220	35.8	5.000	41.8	5.100	47.8	4.680	53.8	3.780
11.9	1.535	17.9	2.435	23 9	3.335	29.9	4.235	35.9	5.000	41 9	5.100	47.9	4.665	53.9	3.765
12.0	1.550	18.0	2.450	24.0	3.350	30.0	4.250	36.0	5.020	42.0	5.100	48.0	4.650	54.0	3.750
12.1	1.565	18.1	2.465	24.1	3.365	30.1	4.265	36.1	5.020	42.1	5.100	48.1	4.635	54.1	3.735
12.2	1.580	18.2	2.480	24 2	3.380	30.2	4.280	36.2	5.020	42 2	5.100	48.2	4.620	54.2	3.720
12.3	1.595	18.3	2.495	24.3	3.395	30.3	4.295	36.3	5.020	42.3	5.100	48.3	4.605	54.3	3.705
12.4	1.610	18.4	2.510	24.4	3.410	30.4	4.310	36.4	5.020	42.4	5.100	48.4	4.590	54.4	3.690
12.5	1.625	18.5	2.525	24.5	3.425	30.5	4.325	36.5	5.020	42 5	5.100	48.5	4.575	54.5	3.675
12.6	1.640	18.6	2.540	24.6	3.440	30.6	4.340	36.6	5.020	42.6	5.100	48.6	4.560	54.6	3.660
12.7	1.655	18.7	2.555	24.7	3.455	30.7	4.355	36.7	5.020	42.7	5.100	48.7	4.545	54.7	3.645
12.8	1.670	18.8	2.570	24.8	3.470	30.8	4.370	36.8	5.020	42.8	5.100	48.8	4.530	54.8	3.630
12.9	1.685	18.9	2.585	24.9	3.485	30.9	4.385	36.9	5.020	42 9	5.100	48.9	4.515	54.9	3.615
13.0	1.700	19.0	2.600	25.0	3.500	31.0	4.400	37.0	5.040	43.0	5.100	49.0	4.500	55.0	3.600
13.1	1.715	19.1	2.615	25.1	3.515	31.1	4.415	37.1	5.040	43.1	5.100	49.1	4.485		
13.2	1.730	19.2	2.630	25 2	3.530	31.2	4.430	37.2	5.040	43 2	5.100	49.2	4.470		
13.3	1.745	19.3	2.645	25 3	3.545	31.3	4.445	37.3	5.040	43 3	5.100	49.3	4.455		
13.4	1.760	19.4	2.660	25.4	3.560	31.4	4.460	37.4	5.040	43.4	5.100	49.4	4.440		
13.5	1.775	19.5	2.675	25 5	3.575	31.5	4.475	37.5	5.040	43 5	5.100	49.5	4.425		
13.6	1.790	19.6	2.690	25.6	3.590	31.6	4.490	37.6	5.040	43.6	5.100	49.6	4.410		
13.7	1.805	19.7	2.705	25.7	3.605	31.7	4.505	37.7	5.040	43.7	5.100	49.7	4.395		
13.8	1.820	19.8	2.720	25.8	3.620	31.8	4.520	37.8	5.040	43.8	5.100	49.8	4.380		
13.9	1.835	19.9	2.735	25 9	3.635	31.9	4.535	37.9	5.040	43 9	5.100	49.9	4.365		
14.0	1.850	20.0	2.750	26.0	3.650	32.0	4.550	38.0	5.060	44.0	5.100	50.0	4.350		
14.1	1.865	20.1	2.765	26.1	3.665	32.1	4.565	38.1	5.060	44.1	5.100	50.1	4.335		
14.2	1.880	20.2	2.780	26 2	3.680	32.2	4.580	38.2	5.060	44 2	5.100	50.2	4.320		
14.3	1.895	20.3	2.795	26 3	3.695	32.3	4.595	38.3	5.060	44 3	5.100	50.3	4.305		
14.4	1.910	20.4	2.810	26.4	3.710	32.4	4.610	38.4	5.060	44.4	5.100	50.4	4.290		
14.5	1.925	20.5	2.825	26 5	3.725	32.5	4.625	38.5	5.060	44 5	5.100	50.5	4.275		
14.6	1.940	20.6	2.840	26.6	3.740	32.6	4.640	38.6	5.060	44.6	5.100	50.6	4.260		
14.7	1.955	20.7	2.855	26.7	3.755	32.7	4.655	38.7	5.060	44.7	5.100	50.7	4.245		
14.8	1.970	20.8	2.870	26.8	3.770	32.8	4.670	38.8	5.060	44.8	5.100	50.8	4.230		
14.9	1.985	20.9	2.885	26 9	3.785	32.9	4.685	38.9	5.060	44 9	5.100	50.9	4.215		
15.0	2.000	21.0	2 900	27.0	3.800	33.0	4.700	39.0	5.080	45.0	5.100	51.0	4.200		
15.1	2.015	21.1	2.915	27.1	3.815	33.1	4.715	39.1	5.080	45.1	5.085	51.1	4.185		
15.2	2.030	21.2	2.930	27.2	3.830	33.2	4.730	39.2	5.080	45 2	5.070	51.2	4.170		
15.3	2.045	21.3	2.945	27.3	3.845	33.3	4.745	39.3	5.080	45 3	5.055	51.3	4.155		
15.4	2.060	21.4	2.960	27.4	3.860	33.4	4.760	39.4	5.080	45.4	5.040	51.4	4.140		
15.5	2.075	21.5	2.975	27.5	3.875	33.5	4.775	39.5	5.080	45 5	5.025	51.5	4.125		
15.6	2.090	21.6	2.990	27.6	3.890	33.6	4.790	39.6	5.080	45.6	5.010	51.6	4.110		
15.7	2.105	21.7	3.005	27.7	3.905	33.7	4.805	39.7	5.080	45.7	4.995	51.7	4.095		
15.8	2.120	21.8	3.020	27.8	3.920	33.8	4.820	39.8	5.080	45.8	4.980	51.8	4.080		
15.9	2.135	21.9	3.035	27 9	3.935	33.9	4.835	39.9	5.080	45 9	4.965	51.9	4.065		

For API GRAVITY values above 55.0° API the differential continues to decline 0.015/ bbl. per 0.1° API GRAVITY.

ATTACHMENT E-5
GRAVCAP TABLE SULFUR.

GRAVCAP, INC.
ADJUSTMENT AUTHORIZATION

TABLES OF DIFFERENTIALS FOR USE IN DETERMINING ADJUSTMENTS FOR
DIFFERENCE IN SULFUR CONTENT FOR CRUDE PETROLEUM

WHITE CAP SYSTEM - BONITO PIPE LINE COMPANY - SHIP SHOAL SYSTEM - CAPLINE SYSTEM

PERCENT SULFUR	DIFF. PER BBL	PERCENT SULFUR	DIFF. PER BBL	PERCENT SULFUR	DIFF. PER BBL	PERCENT SULFUR	DIFF. PER BBL	PERCENT SULFUR	DIFF. PER BBL	PERCENT SULFUR	DIFF. PER BBL	PERCENT SULFUR	DIFF. PER BBL
0.00	1.000	0.60	1.600	1.20	2.200	1.80	2.800	2.40	3.400	3.00	4.000	3.60	4.600
0.01	1.010	0.61	1.610	1.21	2.210	1.81	2.810	2.41	3.410	3.01	4.010	3.61	4.610
0.02	1.020	0.62	1.620	1.22	2.220	1.82	2.820	2.42	3.420	3.02	4.020	3.62	4.620
0.03	1.030	0.63	1.630	1.23	2.230	1.83	2.830	2.43	3.430	3.03	4.030	3.63	4.630
0.04	1.040	0.64	1.640	1.24	2.240	1.84	2.840	2.44	3.440	3.04	4.040	3.64	4.640
0.05	1.050	0.65	1.650	1.25	2.250	1.85	2.850	2.45	3.450	3.05	4.050	3.65	4.650
0.06	1.060	0.66	1.660	1.26	2.260	1.86	2.860	2.46	3.460	3.06	4.060	3.66	4.660
0.07	1.070	0.67	1.670	1.27	2.270	1.87	2.870	2.47	3.470	3.07	4.070	3.67	4.670
0.08	1.080	0.68	1.680	1.28	2.280	1.88	2.880	2.48	3.480	3.08	4.080	3.68	4.680
0.09	1.090	0.69	1.690	1.29	2.290	1.89	2.890	2.49	3.490	3.09	4.090	3.69	4.690
0.10	1.100	0.70	1.700	1.30	2.300	1.90	2.900	2 50	3.500	3.10	4.100	3.70	4.700
0.11	1.110	0.71	1.710	1.31	2.310	1.91	2.910	2 51	3.510	3.11	4.110	3.71	4.710
0.12	1.120	0.72	1.720	1.32	2.320	1.92	2.920	2 52	3.520	3.12	4.120	3.72	4.720
0.13	1.130	0.73	1.730	1.33	2.330	1.93	2.930	2 53	3.530	3.13	4.130	3.73	4.730
0.14	1.140	0.74	1.740	1.34	2.340	1.94	2.940	2 54	3.540	3.14	4.140	3.74	4.740
0.15	1.150	0.75	1.750	1.35	2.350	1.95	2.950	2 55	3.550	3.15	4.150	3.75	4.750
0.16	1.160	0.76	1.760	1.36	2.360	1.96	2.960	2 56	3.560	3.16	4.160	3.76	4.760
0.17	1.170	0.77	1.770	1.37	2.370	1.97	2.970	2 57	3.570	3.17	4.170	3.77	4.770
0.18	1.180	0.78	1.780	1.38	2.380	1.98	2.980	2 58	3.580	3.18	4.180	3.78	4.780
0.19	1.190	0.79	1.790	1.39	2.390	1.99	2.990	2 59	3.590	3.19	4.190	3.79	4.790
0.20	1.200	0.80	1.800	1.40	2.400	2.00	3.000	2.60	3.600	3.20	4.200	3.80	4.800
0.21	1.210	0.81	1.810	1.41	2.410	2.01	3.010	2.61	3.610	3.21	4.210	3.81	4.810
0.22	1.220	0.82	1.820	1.42	2.420	2.02	3.020	2.62	3.620	3.22	4.220	3.82	4.820
0.23	1.230	0.83	1.830	1.43	2.430	2.03	3.030	2.63	3.630	3.23	4.230	3.83	4.830
0.24	1.240	0.84	1.840	1.44	2.440	2.04	3.040	2.64	3.640	3.24	4.240	3.84	4.840
0.25	1.250	0.85	1.850	1.45	2.450	2.05	3.050	2.65	3.650	3.25	4.250	3.85	4.850
0.26	1.260	0.86	1.860	1.46	2.460	2.06	3.060	2.66	3.660	3.26	4.260	3.86	4.860
0.27	1.270	0.87	1.870	1.47	2.470	2.07	3.070	2.67	3.670	3.27	4.270	3.87	4.870
0.28	1.280	0.88	1.880	1.48	2.480	2.08	3.080	2.68	3.680	3.28	4.280	3.88	4.880
0.29	1.290	0.89	1.890	1.49	2.490	2.09	3.090	2.69	3.690	3.29	4.290	3.89	4.890
0.30	1.300	0.90	1.900	1.50	2.500	2.10	3.100	2.70	3.700	3.30	4.300	3.90	4.900
0.31	1.310	0.91	1.910	1.51	2.510	2.11	3.110	2.71	3.710	3.31	4.310	3.91	4.910
0.32	1.320	0.92	1.920	1.52	2.520	2.12	3.120	2.72	3.720	3.32	4.320	3.92	4.920
0.33	1.330	0.93	1.930	1.53	2.530	2.13	3.130	2.73	3.730	3.33	4.330	3.93	4.930
0.34	1.340	0.94	1.940	1.54	2.540	2.14	3.140	2.74	3.740	3.34	4.340	3.94	4.940
0.35	1.350	0.95	1.950	1.55	2.550	2.15	3.150	2.75	3.750	3.35	4.350	3.95	4.950
0.36	1.360	0.96	1.960	1.56	2.560	2.16	3.160	2.76	3.760	3.36	4.360	3.96	4.960
0.37	1.370	0.97	1.970	1.57	2.570	2.17	3.170	2.77	3.770	3.37	4.370	3.97	4.970
0.38	1.380	0.98	1.980	1.58	2.580	2.18	3.180	2.78	3.780	3.38	4.380	3.98	4.980
0.39	1.390	0.99	1.990	1.59	2.590	2.19	3.190	2.79	3.790	3.39	4.390	3.99	4.990
0.40	1.400	1.00	2.000	1.60	2.600	2.20	3.200	2.80	3.800	3.40	4.400	4.00	5.000
0.41	1.410	1.01	2.010	1.61	2.610	2.21	3.210	2.81	3.810	3.41	4.410		
0.42	1.420	1.02	2.020	1.62	2.620	2.22	3.220	2.82	3.820	3.42	4.420	For Sulfur Values above 4.00%, the differential continues to increase 0.01/ BBL per 0.01 Percent Sulfur	
0.43	1.430	1.03	2.030	1.63	2.630	2.23	3.230	2.83	3.830	3.43	4.430		
0.44	1.440	1.04	2.040	1.64	2.640	2.24	3.240	2.84	3.840	3.44	4.440		
0.45	1.450	1.05	2.050	1.65	2.650	2.25	3.250	2.85	3.850	3.45	4.450		
0.46	1.460	1.06	2.060	1.66	2.660	2.26	3.260	2.86	3.860	3.46	4.460		
0.47	1.470	1.07	2.070	1.67	2.670	2.27	3.270	2.87	3.870	3.47	4.470		
0.48	1.480	1.08	2.080	1.68	2.680	2.28	3.280	2.88	3.880	3.48	4.480		
0.49	1.490	1.09	2.090	1.69	2.690	2.29	3.290	2.89	3.890	3.49	4.490		
0.50	1.500	1.10	2.100	1.70	2.700	2.30	3.300	2 90	3.900	3.50	4.500		
0.51	1.510	1.11	2.110	1.71	2.710	2.31	3.310	2 91	3.910	3.51	4.510		
0.52	1.520	1.12	2.120	1.72	2.720	2.32	3.320	2 92	3.920	3.52	4.520		
0.53	1.530	1.13	2.130	1.73	2.730	2.33	3.330	2 93	3.930	3.53	4.530		
0.54	1.540	1.14	2.140	1.74	2.740	2.34	3.340	2 94	3.940	3.54	4.540		
0.55	1.550	1.15	2.150	1.75	2.750	2.35	3.350	2 95	3.950	3.55	4.550		
0.56	1.560	1.16	2.160	1.76	2.760	2.36	3.360	2 96	3.960	3.56	4.560		
0.57	1.570	1.17	2.170	1.77	2.770	2.37	3.370	2 97	3.970	3.57	4.570		
0.58	1.580	1.18	2.180	1.78	2.780	2.38	3.380	2 98	3.980	3.58	4.580		
0.59	1.590	1.19	2.190	1.79	2.790	2.39	3.390	2 99	3.990	3.59	4.590		

APPENDIX F - MAINTENANCE OBLIGATIONS AND REQUIREMENTS FOR FACILITY

F-1. OVERVIEW. The LESSEE is expected to know and use all applicable API and DOT guidelines and standards, as well as, standard industry maintenance practices as a carrier for crude oil. Additionally, the GOVERNMENT requires the LESSEE to include the following requirements in the LESSEE's Maintenance, Repair and Major Maintenance Program which in some cases, are more stringent, but in no case will be less than the standard at which Lessee maintains and operates EMPCo owned facilities. DOE considers the submitted maintenance plans to be an important part of its decisioning related to bid evaluation and as such, incorporates said document by reference as part of this Appendix, section F-9.

F-2. GENERAL REQUIREMENTS

LESSEE must utilize a written facility maintenance plan, based upon industry and government requirements, that implements maintenance program strategy, responsibilities, initiatives and activities.
LESSEE must have a complete set of approved maintenance procedures before start of operations.
LESSEE must have an acceptable Management of Change (MOC) process and use it during the course of the lease.
LESSEE must create and maintain a complete set of drawings, documentation and software using MOC process.
LESSEE MOC process reports must be provided to the GOVERNMENT regularly, as changes occur.
LESSEE must use the SPR ECP process for anything that deviates or changes fit / form or function from what is currently in the facility.

F-3. MARINE DOCKS AND LOADING EQUIPMENT.

No additional requirements beyond industry and government standards.

F-4. TANK TERMINAL AND FACILITY MECHANICAL EQUIPMENT

The LESSEE will be required to comply with API653 for storage tank inspections. Results of the inspections will be communicated to the GOVERNMENT for the purpose of mutually determining required repairs and future inspection intervals. Custody Transfer Meters, Samplers, Densitometer and Prover - No additional requirements beyond industry and government standards. Pumps - No additional requirements beyond industry and government standards. Valves - No additional requirements beyond industry and government standards.

F-5. FACILITY PIPING AND PIPELINES.

The LESSEE will implement a site piping and pipeline integrity monitoring program that regularly measures pipe wall thickness changes over time. Any time the monitoring program finds remaining wall thickness less than 50% of the nominal wall thickness, the LESSEE will perform a more substantial investigation and report findings to the GOVERNMENT. LESSEE will immediately restore any pipe section with remaining wall thickness less than 50% of the nominal wall thickness. High Consequence Areas - No additional requirements beyond industry and government standards. Right of Ways - No additional requirements beyond industry and government standards.

F-6. ENVIRONMENTAL AND SAFETY SYSTEMS.

No additional requirements beyond industry and government standards.

F-7. FIRE SYSTEMS

LESSEE will maintain all Fire Systems in accordance with the latest NFPA (National Fire Protection Association) Codes and Standards.

F-8. UTILITIES, BUILDINGS AND SECURITY SYSTEMS.

No additional requirements beyond industry and government standards.

F-9. ST. JAMES DEPARTMENT OF ENERGY FACILITY SITE MAINTENANCE PLAN

EMPCo Written Plan follows next page:

ST. JAMES DEPARTMENT OF ENERGY FACILITY

SITE MAINTENANCE PLAN

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St. James Department of Energy Facility

Maintenance Plan

1.0 Introduction

1.1 Executive Summary

The ExxonMobil Pipeline Company (EMPCo) is part of the Midstream Organization and is headquartered in Houston, TX. EMPCo operates pipelines in 5 states and the Gulf of Mexico. The organization employs approximately 700 employees who oversee the transportation of approximately 3 million barrels per day of crude oil and refined products through approximately 4,000 miles of owned pipeline and 46 tanks.

Organizationally, EMPCo is divided into five operational areas in the United States- US South, US Mid-Atlantic/Southeast, Chemicals, US Midwest/Northeast, and US Rockies/West Coast.

EMPCo carefully maintains and monitors their infrastructure worldwide to identify and prevent corrosion, third-party damage, or illegal intrusions onto EMPCo right-of-ways. ExxonMobil's worldwide marine business, which involves about 500 vessels in daily service, logged more than 21,000 voyages and 40,000 port calls in 2017, safely transporting approximately 1.2 billion barrels of crude oil and refined products.

EMPCo is committed to conducting business in a manner compatible with the environmental and economic needs of all communities where it operates and in a manner that protects the safety and health of employees, those involved in EMPCo operations, EMPCo customers, and the public. Commitment to safety, health, and the environment is a longstanding ExxonMobil core value. Continuously improving all aspects of environmental performance is a key business objective that is monitored at every level.

ExxonMobil incorporates rigorous safety standards and procedures into facilities' design, construction, and operating activities. This document serves to provide a high level overview of the comprehensive collection of EMPCo's design guides/specifications, maintenance programs, operating manuals, project management guides, Safe Work Practices, and integrity standards. As part of ExxonMobil's commitment to being the world's premier petroleum and petrochemical company, these documents are periodically reviewed and updated to ensure facilities continue to be operated safely and responsibly. Upon request, additional details of these robust programs can be provided for review.

1.2 Facility Description

The St. James Department of Energy facility is comprised of two marine docks on the Mississippi River occupying approximately 48 acres of land, a tank terminal occupying approximately 105 acres of land, one 36" pipeline with connectivity to outside facilities, several connections that lead to other oil transfer facilities plus the environmental and safety systems that serve the entire St. James facility.

The two marine docks are located approximately two miles southeast of the tank terminal. Dock 1 is located at Mississippi River milepost 158.3, and Dock 2 is located at Mississippi River milepost 158.0. Both docks are concrete and steel construction with four breasting dolphins and eight mooring dolphins with capstan motors and quick release "pelican hooks." Each dock is equipped with three 16-inch Continental Emsco hydraulically operated loading arms, a 5-ton hydraulic crane, in-line sampler and a control room equipped with operational control, status, and monitoring of fluid transfer with emergency shutdown controls. Each dock is connected to the terminal with a 42-inch crude oil line, a 6-inch oily water return line, and a 2-inch potable water feed line. The terminal's back-up firewater pumping system is located at Dock 1 and supplies primary fire water to both docks.

The tank terminal provides crude oil storage, pumping, metering, and distribution. The tank terminal consists of six storage tanks totaling approximately two million barrels of capacity, crude oil pumping stations, metering stations, and control and maintenance facilities.

The six storage tanks have a total shell capacity of approximately 2 million barrels. The tanks are approximately 33 feet high and have a single skin-floating roof. Each of the tanks is equipped with mixers and temperature and level gauging instrumentation. The six tanks are sited in two groups of three, which are each surrounded by a community dike system. Each of the two diked areas could contain the entire volume of one tank with some freeboard allowance. Minor spillage is contained by lower internal dikes between the tanks.

The primary pump station consists of five Peabody-Floway vertical, deep well, three-stage pumps with a designed capacity at discharge of 25,000 barrels-per-hour at 288 feet of head each. They are driven by 1,500 horsepower electric motors. The pump station is manifolded to provide two independent pumping units of two pumps each: Pumps 1 and 2, and Pumps 4 and 5. Pump 3 is manifolded into both systems as an on-line spare.

The terminal also has a second pumping station which contains three horizontal centrifugal pumps rated at 10,000 barrels-per-hour each at 460 psi discharge that are driven by 1,375 horsepower electric motors.

The tank terminal has two meter stations. Each meter station consists of three 12-inch meter runs equipped with in-line turbine meters having a rated capacity of approximately 18,000 barrels-per-hour each. The meters are calibrated and proved by a unidirectional prover loop adjacent to the meter station.

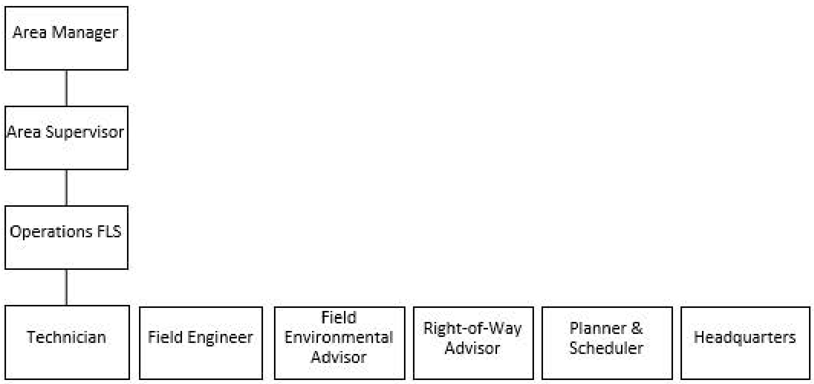
There are five primary buildings at the terminal: Administration Building, Contractor Office Building, Maintenance Building, Spare Parts Warehouse, and Oil Quality Assurance Laboratory. In addition, there are several minor buildings such as the Security Center and various small buildings for safety and oil spill equipment.

1.3 Organization and Function

EMPCo currently has extensive operations in the St. James and Baton Rouge area and would operate this facility to the same standards and practices as assets owned throughout the company.

This includes responsibly maintaining the facility and refurbishing/replacing major equipment that includes but is not limited to tank components, facility piping, pump components, valves and/or valve components, dock components, and building components.

Outlined below is a high level overview of resources that make up the Mid-Atlantic Southeast (MASE) operations group that operate in the St. James and Baton Rouge area. These resources are regularly reviewed and updated to ensure that the area is properly staffed to handle day-to-day operations as well as upcoming initiatives.



<u>Area Manger</u>
Oversees a geographic area, and actively manages operational resources, budget, and risk to effectively manage area operating assets.

<u>Area Supervisor</u>
Oversees a defined operating area, and helps manage operational resources, budget, and risk to effectively utilize area operating assets.

Actively works with First Line Supervisor to perform frequent touchpoints to ensure consistency with all Safe Work Practices (SWPs), Tier 1 Best Practices, and Life Saving Rules.

<u>Operations First Line Supervisor (FLS)</u>
Oversees day-to-day operations for a defined operations team, and develops operational resources and budgets to effectively utilize area operating assets.

Actively works with technicians to ensure day-to-day operations are performed safely and in compliance with regulatory requirements.

<u>Technician</u>
Provides day-to-day, multi-discipline field support/troubleshooting and actively recommends, develops, and implements practical solutions to effectively utilize operating assets.

Works hands on with contractors and third parties to ensure work is compliant with SWPs and design standards.

<u>Field Engineer</u>
Provides day-to-day, multi-discipline technical support and troubleshooting for a defined operating area, and actively participates with the Operating Business Team to recommend, develop, and implement practical solutions to effectively utilize and manage area operating assets.

Field Environmental Advisor
Direct support for field personnel and engineering to ensure that all regulatory and company environmental standards are followed for projects and day-to-day operations.

Right-of-Way Agent
Works with landowners and public entities to establish and maintain working relationships along company right-of-ways and operating areas.

Provides guidance to field personnel and engineering to ensure compliance with land owner agreements and local requirements.

Planner and Scheduler
Develops and maintains the Systems, Applications & Products (SAP) database used to store equipment information, actively track operational/regulatory activities, and generate work orders.

Works hand-in-hand with First Line Supervisors, Technicians, and Field Engineers to ensure regulatory deadlines are met for the verification and testing of equipment.

Headquarters
In addition to the work group located in the St. James and Baton Rouge area, support is provided by a vast network of ExxonMobil Headquarters staff. This includes the Global Pipeline and Integrity Group, Safety Health and Environmental Team, Business Development and Joint Interest Team, Accounting and Controllers Team, Senior Design Engineers, Legal Team, and Project Development and Execution Team.

These teams will work together to ensure all objectives and goals are met and that these facilities will be drawdown ready with thirteen (13) days notice.

1.4 Operations Integrity Management System

ExxonMobil has developed an Operations Integrity Management System (OIMS) which establishes a framework for addressing risk across all aspects of the company's operations. OIMS, which is built around 11 key elements of risk, is embedded into everyday work processes in each of the areas of safety at ExxonMobil. Each element comprises a number of expectations — 65 in all — that provide greater detail.

OIMS is embedded into everyday work processes at all levels. Managing procedures within the OIMS framework provides a structure to help monitor continuous improvement. This is why the first element of OIMS is management leadership, commitment, and accountability. In an industry which operates 24 hours a day, around the world — the need to manage risk never ends. Even the best safety framework should be viewed as a work in progress because developing a culture of safety is a continuous journey.

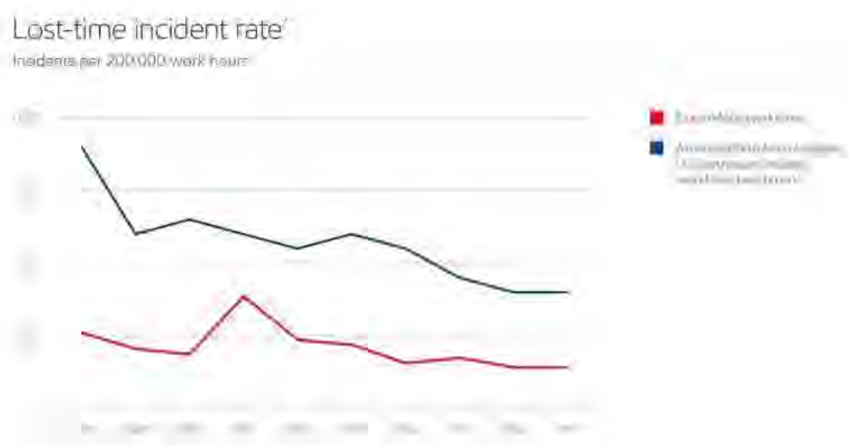
2.0 Safety

ExxonMobil expects every employee and third-party contractor to take action when they observe an at-risk situation or unsafe behavior, regardless of whether the worker is a supervisor, experienced employee, new hire, or contractor. Tools and training are provided to foster a culture of safety that empowers ExxonMobil's global workforce to intervene or stop work when necessary.

Systems, programs, and practices are periodically assessed to identify opportunities for improvement. ExxonMobil works to identify underlying causes associated with incidents and near-misses, and to refine approaches in response to these findings.

ExxonMobil's management approach to personnel safety includes a consistent framework to describe actual and potential injury severity. This includes continuing to minimize actual injury severity, allow potential injury severity to drive priorities, and focus on preventing all injuries to enable ExxonMobil's desired culture of caring and alignment with the company's safety vision.

In 2017, ExxonMobil's workforce lost-time incident rate per 200,000 work hours was 0.029, consistent with the previous year. Since 2000, this rate has been reduced by 80 percent. When compared with the American Petroleum Institute's U.S. petroleum industry workforce benchmark, ExxonMobil continues to outperform industry peers in safety performance.



ExxonMobil's commitment to safety starts at the top, is driven throughout the businesses, and is consistent at all operating locations. Employees, contractors, and communities depend on ExxonMobil to provide the training, tools, and processes to keep them safe and healthy every day.

2.1 Safety Credo

We, the management and employees of EMPCo, believe that while risk exists:

- Accidents and injuries are preventable
- Each of us has a personal responsibility for our safety and the safety of others both on and off the job
- No business objective is so important that it will be pursued at the sacrifice of safety
- Safe conduct of operations is a condition of employment at EMPCo
- A job is well done only if it is done safely
- EMPCo should have the best safety performance in the pipeline industry

2.2 Loss Prevention System

In order to integrate a safety culture across all aspects of the business, EMPCo has adopted and implemented a world renowned behavior based system known as the Loss Prevention System (LPS).

LPS is a system to prevent or reduce losses using behavior-based tools and proven management techniques. This prevention or reduction of losses is accomplished in a work culture that:

- Emphasizes proactive activities
- Capitalizes on the job expertise of employees
- Maximizes use of positive reinforcement
- Integrates the LPS tools with the daily business
- Practices "providing direction from the top down while solving problems from the bottom up"

The goal is to prevent or reduce the occurrence of seven types of losses:

- Personal injuries
- Equipment or property damage (includes motor vehicle crashes and fires)
- Product quality losses (includes spills and leaks)

- Regulatory assessments
- Operational or system inefficiencies
- Financial losses
- Near losses

LPS has four principles that are essential to its success, which are highlighted below:

- Principle 1: Everyone must participate. The approach to LPS implementation should be that the overall direction will be provided from the "top down," while determination of such specifics as how to best use the LPS tools will be from the "bottom up." All levels of the company must be actively involved, with each person having the opportunity to develop ownership and an identity that includes the daily use of LPS tools and activities.

- Principle 2: Integrate LPS tools and activities with the daily business. All LPS tools and activities should be designed and developed so that they are integrated into the normal, recurring business affairs of the organization. Some of the LPS activities occur daily, while others take place weekly or monthly. Nonetheless, communication of losses, and near losses, Loss Prevention Self-Assessment (LPSA), Job Loss Analysis (JLA), Loss Investigations (LI), Near Loss Investigations (NLI), and Loss Prevention Observations (LPO) must be performed as part of the job, just like any task is part of the normal business.

- Principle 3: Develop and communicate the LPS plan. This principle means that the organization's overall business plan must include LPS. Each employee should know the generalities of the overall LPS plan and, at the same time, be familiar with the specifics of his/her role to help achieve LPS goals and objectives.

- Principle 4: Address risks before a loss occurs. Although LPS includes investigations of losses that already have occurred, the majority of time spent on LPS tools and activities should be proactive. In other words, most of LPS's efforts should focus on identification and elimination of risks before an injury or other type of loss takes place, not after the fact.

2.3 Safe Work Practices

ExxonMobil has developed an extensive collection of 45 Safe Work Practices (SWPs) to provide the guidance and direction necessary to ensure each person has the knowledge to recognize hazards and implement the appropriate measures to eliminate or mitigate the hazards and complete the work activity safely. Safe Work Practices are applicable to ExxonMobil Midstream employees, contractors, and physical assets associated with operations and maintenance of facilities and work activities within the Midstream portfolio.

SWPs provide instruction on the processes implemented to comply with the requirements established by ExxonMobil Tier 1 Best Practices, regulatory agencies (e.g., OSHA, CSA), and other governing bodies. The SWPs are reviewed on a periodic frequency to validate the content and revised accordingly to ensure alignment with associated requirements. The review and revision of SWPs is completed by subject matter experts knowledgeable on the applicable processes and regulatory requirements. The update and communication of Safe Work Practices are managed according to the Management of Change process.

These SWPs are maintained either electronically or in a printed format and are available for use by all employees and contractors. The current Safe Work Practices include:

- SWP 001: Fall Protection Program
- SWP 002: Scaffolding Program
- SWP 003: Aerial Work Platforms

- SWP 004: Ladder Safety Program
- SWP 005: Confined Space Entry Program
- SWP 006: Crane and Lifting Operations
- SWP 007: Safe Electrical Work Program
- SWP 008: Hazardous Energy Control Standard
- SWP 009: Opening Process Equipment
- SWP 010: Work Permitting Standard
- SWP 012: Personal Protective Equipment
- SWP 013: Gas Testing Standard
- SWP 014: Hot Work/ Low Energy Standard
- SWP 015: Welding Safety
- SWP 016: Abrasive Blasting and Water Blasting
- SWP 017: Contractor Safety
- SWP 018: Powered Industrial Truck Safety Program
- SWP 019: Electrical Safety on Alternating Current Corridors
- SWP 020: Heat and Cold Stress Program
- SWP 021: Respiratory Protection Program
- SWP 022: Hearing Conservation Program
- SWP 023: Hazard Communication Program
- SWP 024: Asbestos Safety Program
- SWP 025: Paintings and Coatings Program
- SWP 026: Benzene Program
- SWP 027: Butadiene Program
- SWP 028: Hydrogen Sulfide Program
- SWP 029a: Ionizing Radiation Safety Program
- SWP 029b: NORM Program
- SWP 030: Tools and Equipment
- SWP 031: Ergonomics
- SWP 032: Office Safety
- SWP 033: portable Battery-Powered Devices
- SWP 034: Transportation Safety
- SWP 035: Health and First Aid
- SWP 036: Blood Borne Pathogens
- SWP 037: Fire and safety Prevention
- SWP 038: Surface-Supplied Diving Operations
- SWP 039: Tank In-Service Entry and Internal Floating Roof Access
- SWP 040: Tank Cleaning Procedures
- SWP 041: Housekeeping and Material Storage
- SWP 042: Silica
- SWP 043: Vacuum Truck Usage
- SWP 044: Critical Safety Equipment Control of Defeat
- SWP 045: Potable Water

ExxonMobil Corporation has also established the following Tier 1 Best Practices (BPs) which identify the minimum global requirements for those work activities that present higher risks to personnel safety and health. Tier 1 Best Practices are developed by a team of subject matter experts representing manufacturing affiliates, including Midstream. The Tier 1 BPs identify critical life safety measures which define layers of protection (LoP) which establish protection against life safety hazards. The LoPs are intended to establish greater consistency with the processes used to meet the Tier 1 BP requirements.

The following Tier 1 BPs have been adopted by the Midstream organization and have the following Safe Work Practices associated with them:

- Working at Heights – SWP 001: Fall Protection Program, SWP 002: Scaffolding Program, SWP 003: Aerial Work Platforms, and SWP 004: Ladder Safety Program
- Confined Space Entry – SWP 005: Confined Space Entry Program
- Crane and Lifting Operations – SWP 006: Crane and Lifting Operations
- Energy Isolation – SWP 008: Hazardous Energy Control Standard
- Opening Process Equipment – SWP 009: Opening Process Equipment Standard
- Electrical Safety Related Work Practices – SWP 007: Safe Electrical Work Program, and SWP 019: Electrical Safety on Alternating Current Corridors
- Tank Cleaning – SWP 039: Tank In-Service Entry and Internal Floating Roof Access, and SWP 040: Tank Cleaning Procedures

In addition to Tier 1 BPs, Life Saving Rules were developed to raise awareness for the importance of following key safety rules that, if not followed, can quickly and directly lead to serious incidents. The following rules were chosen based on ExxonMobil and industry incident history and have the following Safe Work Practices and/or Manual associated with them:

- Working at Heights – SWP 001: Fall Protection Program, SWP 002: Scaffolding Program, SWP 003: Aerial Work Platforms, and SWP 004: Ladder Safety Program
- Work Permitting – SWP 010: Work Permitting Program, SWP 012: Personal Protective Equipment Standard, SWP 013: Gas Testing Standard, and SWP 014: Hot Work/Low Energy Standard
- Energy Isolation – SWP 008: Hazardous Energy Control Standard
- Critical Safety Device Defeat – SWP 044: Critical Safety Equipment Control of Defeat
- Excavation Safety – EMPCo Excavation Manual

2.4 High Risk Operations

EMPCo has also identified a collection of Higher Risk Operations (HROs) which are operations that pose a potentially higher risk due to their special nature. Most HROs require additional considerations to ensure they are performed safely.

All HROs listed below must be reviewed and approved by the appropriate supervisory level before performing the work. HROs must have trained personnel involved in or providing full oversight to the task. Skills to perform the task are to be verified prior to execution, consistent with the requirements EMPCo's Personnel and Training System. The activities that have been identified as HROs are as follows:

- Hazardous confined space entry
- Non-hazardous confined space entry
- Trench excavations >20 feet deep requiring personnel entry
- Non-standard lift
- Critical lifts and lifts of personnel
- High voltage switching >11Kv
- Work by or presence of an unqualified person on or near exposed energized electrical equipment
- Any opening of process equipment where positive isolation cannot be verified
- All tank cleaning
- Scaffolding operations
- All working at height tasks using rope work to suspend a person
- Certain hot tapping tasks
- Abrasive blasting on "in service" pipelines /facilities with pitting or suspected wall loss >50%
- Hot work on "in service" pipelines or facility equipment
- Major tank maintenance and repair tasks on atmospheric storage tanks

- Hot work on "in service" atmospheric petroleum storage tanks
- Cutting a tank containment to obtain access to an "in service" piece of equipment
- Nitrogen purging / drying of pipeline and facilities requiring the use of a nitrogen truck
- Commissioning / decommissioning pipelines and pipeline facilities
- Moving / lowering pipelines
- Directional boring for pipeline installation
- Hydro-testing of pipelines / facilities / equipment
- Leak testing of pipelines with product
- Maintenance or repair work on marine vessels at facility dock
- Product transfers (tank to tank) using water draw off connections
- Use of unusual Marine Vessels at terminal docks such as cranes barges or dredging
- Use of unusual high intensity equipment
- Demolition of major / significant equipment or facilities
- Use of and handling of toxic chemicals presenting exposures immediately dangerous to life or health or naturally occurring radioactive materials

3.0 Regulatory Compliance

3.1 Public Awareness

EMPCo is committed to following the guidelines set forth in RP 1162 First Edition, December 2003. To that end, the EMPCo Public Awareness Program (PA Program) was developed. The EMPCo PA Program was implemented June 19, 2006. The PA Program is organized in accordance with the 12 Steps that the American Petroleum Institute has defined within RP 1162 and is intended to closely align with the requirements of EMPCo's Operations Integrity Management.

The scope and objectives of EMPCo's Public Awareness Program element are to manage the company's relationships with external audiences and to ensure that community expectations and concerns about EMPCo's operations are recognized and addressed in a timely manner.

This internal community awareness program at EMPCo predates the PA Program developed from RP 1162.

EMPCo's Public Awareness Program's overall goal is to enhance public safety and environmental protection through increased public awareness and knowledge of EMPCo pipeline operations. To that end, the Public Awareness Program has these program objectives:

- Increased public awareness of EMPCo pipelines
- Better public understanding of pipeline damage prevention and emergency response procedures
- Identification and implementation of "baseline" and "supplemental" PA Program initiatives
- Evaluation of PA Program effectiveness
- Identification and implementation of PA Program "continuous improvement" actions steps
- Documentation of PA Program activities

A more informed public along pipeline routes will:

- Enhance EMPCo pipeline safety measures and contribute to reducing the likelihood and potential impact of pipeline emergencies and releases
- Understand that while pipeline incidents are unlikely, according to the Department of Transportation (DOT), pipelines are a safe mode of transportation and EMPCo utilizes a variety of measures to prevent pipeline accidents
- Know that they have a significant role in helping to prevent accidents that are caused by third-party damage and right-of-way encroachment

The PA Program is also intended to help the public understand the steps that should be taken to prevent and respond to pipeline emergency situations. Specific goals include reducing the occurrence of pipeline emergencies caused by third-party damage through the awareness of safe excavation practices and the use of the One-Call System. A critical objective is to highlight the steps that should be taken to protect life, property, and the environment if a pipeline emergency does occur. These steps include promptly notifying pipeline operators and emergency response officials in the event of a pipeline release or emergency.

3.2 DOT

EMPCo has developed a DOT Manual to meet the regulatory compliance requirements of the Department of Transportation covering pipelines owned and/or operated by EMPCo or an affiliated company in which EMPCo owns an interest.

The objective of this manual is to provide operations and maintenance procedures for safe operations of regulated facilities owned and operated by EMPCo. These procedures were developed to assure safe and dependable operation through continuing surveillance of the pipeline facilities and periodic reporting of facility and environmental conditions. When facility surveillance or reports indicate unusual or abnormal conditions, an investigation shall be initiated to determine the cause and the appropriate corrective action to be taken.

This manual covers the following topics:

- Reporting Accidents and Safety-Related Conditions (Including Annual Reporting)
- Design Requirements
- Constructions
- Pressure Testing
- Operation and Maintenance
- Qualifications of Pipeline Personnel
- Corrosion Control

While EMPCo has developed an in-depth Facilities Inspection and Maintenance Management System as discussed in Section 5, EMPCo's DOT manual highlights some maintenance requirements for valves and pressure safety devices, which include the following:

- Partial operation of each mainline valve, ***except blow-down valves, idled mainline block valves, and inactive valves,*** shall be performed at intervals not exceeding 7-1/2 months but at least twice each calendar year to determine that it is functioning properly.
- It is recommended that blow-down valves, idled mainline block valves, and inactive valves be visually inspected twice each calendar year, with 7-1/2 month maximum interval between inspections and document accordingly.
- Relief valves and other pressure relieving devices (except rupture disks) shall be tested at intervals not exceeding 15 months, but at least once each calendar year, or in the case of pipelines used to carry highly volatile liquids, at intervals not to exceed 7-1/2 months, but at least twice each calendar year, unless experience dictates shorter intervals, to determine that they are: in good mechanical condition; set to function at the correct pressure; and properly installed and protected from conditions that might prevent proper operation.
- Flex-flo type pressure relieving devices shall be tested in place, at intervals not exceeding 15 months, but at least once each calendar year, or in the case of pipelines used to carry highly volatile liquids, at intervals not to exceed 7-1/2 months, but at least twice each calendar year, to determine that they have **sufficient capacity** to limit the pressure on the facilities to which they are connected to the desired maximum pressure.

3.3 Environmental

EMPCo has created an Enviormental Protection Reference Manual that helps identify and manage the potential environmental impacts of Midstream business operations, facilities and equipment; to achieve continuous improvement in environmental performance; and, to meet the principles imbedded in Corporate Environmental Expectations - *"Protect Tomorrow. Today,"* including the expectation to deliver superior environmental performance, which will lead to a competitive advantage, with the following desired outcomes:

- Environmental aspects are identified, assessed, and managed to minimize the potential for environmental impact
- Proactive environmental plans and measures are in place to prevent systemic environmental incidents and releases
- Continuous progress is made in reducing releases to the environment, emissions, and amount of waste generated

EMPCo is dedicated to protecting the environment by reducing environmental impacts and resource utilization in the manufacture, distribution, use, and disposition of company products. To meet this goal, the following are guides:

- Identifying potential environmental aspects and impacts
- Establishing environmental performance standards, goals and tracking progress, including for Midstream-defined Business Line Environmental Performance Indicators
- Complying with environmental regulations and applying responsible standards where none exist
- Communicating environmental performance results and experiences, internally and externally
- Seeking constructive ongoing dialogue with governments and others to encourage adoption of environmental standards, regulations, and laws that are based on sound science and consider risks, costs, and benefits
- Providing customers with technology-leading products and services with benefits such as improved fuel economy/emissions, extended equipment life, and reduced used oil generation

3.4 Emergency Preparedness

Regardless of the size, severity, or cause of an event, each ExxonMobil facility and business unit has access to a wide array of trained responders and resources. Emergency response teams are routinely tested in accordance with external regulatory requirements and OIMS.

Emergency support groups and incident management teams are established around the world. They comprise representatives from across business functions to develop and practice emergency response strategies. These teams are tested on a range of possible scenarios, including simulated spills, fires, explosions, natural disasters, and security incidents. Emergency support groups and local emergency response teams are supplemented with emergency regional response teams as needed. The three regional response teams — North America; Europe, Africa and the Middle East; and Asia Pacific — consist of diverse ExxonMobil personnel trained in a single incident management system to address a range of scenarios and issues associated with field response.

EMPCo has developed an Emergency Preparedness System with the purpose of ensuring EMPCo has the tools and processes to effectively manage any emergency situation including business continuity. Emergency and business continuity planning and preparedness are essential to ensure that all necessary actions are taken for the protection of the public, the environment, and company personnel and assets, as well as continuity essential business processes and critical operations.

Plans and procedures required by this system include a site-specific Emergency Response Plan (ERP) and Business Continuity Plan (BCP) based on applicable laws and regulations and assessed risks, and will be documented, accessible, and clearly communicated. These plans include:

- The Incident Command System, responsibilities and authorities
- Internal and external communications procedures
- Procedures for accessing personnel and equipment resources
- Procedures for accessing essential safety, health, and environmental information
- Procedures for interfacing with other company and community emergency response organizations
- The rigor of the BCP is commensurate with the assessment of the consequence of potential loss
- BCP scenarios encompass the following consequences as appropriate: loss of people, loss of facilities and/or operational integrity, loss of IT (services or infrastructure), loss of internal or external supplies (services or infrastructure)
- BCPs define critical operations and services and consider documents, staffing needs, critical interdependencies, alternative processing options (workarounds), the sequence for curtailing operations services, and restoration and recovery procedures for these activities

Pipeline systems currently use a regulatory approved response plan format designed to meet the DOT/OPS/RSPA regulations 49 Code of Federal Regulations (CFR) 194. This format includes two volumes. Volume One is the core manual and is common to all EMPCo pipeline plans. It contains general information including organizational information and various response procedures. Volume Two is a Zone Plan for each of the numerous geographic pipeline zones. The Zone Plan contains geographic specific information necessary for quick emergency response actions by local personnel, tier I responses, as well as structure and procedures for extended tier II and III responses.

Regulatory requirements often indicate that response or emergency prevention and detection equipment be listed in the emergency plan. However, inspection and maintenance requirements can be accomplished through the maintenance system and documented as such. Maintenance of emergency response equipment is the responsibility of the Terminal Superintendent or Area Supervisor.

4.0 Design

EMPCo is committed to providing safe, cost effective, and reliable services with zero defects to customers, both internal and external. Using applicable standards and procedures, EMPCo strives to maximize safety and minimize environmental risk at all EMPCo and customer owned facilities, always meeting the mutually agreed requirements of the task at hand and continuously improving the services.

All designs will be in accordance with the EMPCo's OIMS and the ExxonMobil Engineering Practices System (EMEPS). Periodic assessments will aid in detecting any improvements that could enhance the performance of the pipeline facility design.

EMPCo has developed a comprehensive Mechanical Design Guide and Electrical and Instrumentation Design Practices to describe design practices for pipeline facilities. Other project tasks, such as project execution plans, cost estimating, preparation of Piping and Instrumentation Diagrams (P&IDs), drawings, design criteria, material or equipment specifications, hydrostatic testing, Hazard and Operability Reviews (HAZOP), design reviews, etc. are briefly covered in these design guides. Detailed information for these and other tasks are covered in following:

- Over 290 Marine, Terminal, and Pipeline Global Practices (GPs)
- Midstream Small Project Guide (MPG)
- Project System Manual (PSM)
- Facility Piping Standard
- HAZOP Applications Guide
- Pipeline Repair and Modifications Manual
- Pipeline Surveillance Policy and Guidelines
- Pipeline Welding Manual
- Hydrotesting Manual

5.0 Maintenance

ExxonMobil employs structured inspection and maintenance programs to regularly test critical equipment and maintain compliance with applicable regulations. EMPCo is committed to promoting asset integrity and mechanical reliability of its equipment through the establishment of the Facilities Inspection and Maintenance Management System (FIMMS). This program identifies processes and procedures for scheduled inspections, tests, and associated maintenance activities of regulated assets. The program was developed to ensure that inspection and maintenance activities are in compliance with regulatory requirements and are consistent with practices established by industry-recognized agencies, such as American Petroleum Institute (API) and National Association of Corrosion Engineers (NACE).

Many of the maintenance and inspection activities covered by the FIMMS Program have been entered in SAP PM, which is a software used for preventive maintenance planning and scheduling.

The following subsections provide a high level overview of each of the in-depth programs in the FIMMS Manual.

5.1 Corrosion

5.1.1 Cathodic Protection Program

EMPCo has developed a Cathodic Protection Program that describes the requirements for cathodic protection including inspections and associated documentation. The program objective is to provide adequate measures to protect pipeline facilities from damage due to external corrosion. It is also intended to ensure compliance with applicable regulations. This program applies to all regulated assets, including pipelines and tanks. The processes and procedures described in this program apply to both bare and coated assets.

EMPCo and regulatory agencies use established survey requirements and frequencies, which are continually reassessed. EMPCo's intent is to provide cathodic protection (CP) to all regulated assets. All inspections should be scheduled through SAP PM for field implementation. All personnel involved in corrosion control, including the inspection, testing, and evaluation of CP surveys, shall have the appropriate Operator Qualifications (OQs).

A baseline survey should be conducted on each pipeline system following construction or acquisition. The CP system must be operational within one year following construction.

Permanent documentation of the survey results should be retained in the local Area files. This survey may include the following types of measurements:

- Native structure-to-soil potentials (should be performed prior to any sacrificial anode system installation)
- Structure-to-soil potentials (energized)
- Structure-to-soil instant-off potentials (impressed current only)
- Anode current output (output may be read individually or in total depending on system design)
- Casing and carrier pipe potentials to determine electrical isolation
- Continuity of structures if protected as a single structure
- Structure-to-structure isolation if protected separately
- Effect on adjacent structures (stray current effects)
- Rectifier DC volts, DC amps, and tap settings
- Structure-to-soil potentials at foreign crossings
- Interference testing between the protected structure and other cathodically-protected structures

Annual CP surveys are required on all regulated facilities to demonstrate the effectiveness of CP. Annual CP surveys are scheduled through SAP PM. A work order is generated for the completion of the scheduled survey. A separate work order is generated for CP survey data entry in Cathodic Protection Data Manager (CPDM). Completed survey data is entered in CPDM.

All instruments used for inspection and testing shall be calibrated each calendar year. All reference cells used for taking CP measurements (structure-to-soil potentials) shall be checked annually and calibrated as necessary or replaced. Alternatively, a reference cell with certification from the vendor may be used.

Action taken to return a CP system to the required performance level will be site specific. Appropriate action will vary by situation and location. The Engineering Tech (ET)/Corrosion Tech (CT) will determine corrective action based on his/her expertise, troubleshooting, and consultation as necessary with knowledgeable sources and reference materials.

EMPCo's engineering and Field Operation Departments will ensure that electrical test leads for the corrosion control system are installed as follows:

- Be located at intervals frequent enough to obtain electrical measurements indicating the adequacy of cathodic protection

- Provide enough looping or slack so backfilling will not unduly stress or break the lead and the lead will otherwise remain mechanically secure and electrically conductive
- Prevent lead attachments from causing stress concentrations on pipe
- For leads installed in conduits, suitably insulate the lead from the conduit
- At the connection to the pipeline, coat each bared test lead wire and bared metallic area with an electrical insulating material compatible with the pipe coating and the insulation on the wire

Electrical test leads, required for cathodic protection surveys, must be maintained to ensure that accurate electrical measurements can be obtained.

5.1.2 Close Interval Survey Program

EMPCo has developed a Close Interval Survey Program that provides a guideline for the use of close-interval survey (CIS) to identify anomalies that may otherwise be undetected by conventional pipe-to-soil (P/S) potential surveys. Increasing the number of P/S potentials that are taken provides more opportunities for detection of defects in the CP system. The technique is a tool available to obtain more detailed information about the performance of the CP system and the coating system of a pipeline.

When practicable and determined necessary by sound engineering practice, a detailed CIS potential survey should be conducted to (a) assess the effectiveness of the CP system; (b) provide base line operating data; (c) locate areas of inadequate protection levels; (d) identify locations likely to be adversely affected by construction, stray currents, or other unusual environmental conditions; or (e) select areas to be monitored periodically.

EMPCO currently uses In-Line Inspection (ILI) technology where possible to identify external metal loss. Where ILI data shows external metal loss, a CIS may be considered to determine the adequacy of CP. On pipelines where ILI is not practical or feasible, consideration should be given to other information to determine the adequacy of the CP. Other information may include:

- Leak history
- Pipeline inspection and remedial action reports
- Hydrotest records and reports
- Annual pipe-to-soil potential surveys
- Stray current and interference testing
- Rectifier readings
- Foreign bond readings

Factors entering into the determination of which pipelines are considered for CIS may include:

- Population density
- Environmental impact of a potential line failure
- Number of years since any prior CIS was performed on the system and previous survey results
- Historical CP performance
- Age of the pipeline coating
- ILI results

If CIS data is obtained prior to an annual survey regulatory deadline, CIS data may be used to satisfy the annual survey requirement.

When anomalies are discovered during a CIS, evaluation of the data by a Corrosion Specialist and Engineering Tech should dictate what remedial action is necessary. Such remedial action may include:

- Adjustment of available CP current
- Upgrading of existing CP systems
- Installation of additional CP systems
- Adjustment of current drain to or from other structures to which the system is bonded
- Installation of bonds to other cathodically protected structures to mitigate interference
- Reconditioning of damaged or disbonded coating
- Installation of sacrificial galvanic anodes at "hot spots" along the line where the impressed current is not effective, or where foreign interference can be drained without the establishment of a critical bond

5.1.3 Corrosion Under Insulation Program

EMPCo has developed a Corrosion Under Insulation Program that provides a guideline and describes the responsibility for performing and documenting routine external inspection of insulated piping and facilities susceptible to corrosion under insulation (CUI). This program applies to the EMPCo Inspector and/or contract personnel who perform insulated piping inspections. This procedure identifies equipment that is susceptible to CUI, available inspection techniques, suspect areas for CUI, and extent of inspection. For the purposes of this document, insulation includes both spray-applied foam and jacketed type. Insulation is not a coating. Insulation is a product that can conserve energy and thermal efficiency, can be used as a fireproof barrier, a condensation reducer, a product for noise abatement, help maintain process operability and/or temperature stability, provides freeze protection, and provides personal protection. Piping that is temporarily insulated for winterization should be inspected when temporary insulation is removed, not exceeding regulatory intervals.

All personnel involved in the inspection, testing, and evaluation of insulated piping shall have the appropriate OQs. Possible associated OQ-covered tasks are Inspecting Exposed Pipe and Performing Atmospheric Surveys, Coating or Recoating Pipe, and Determining Wall Thickness.

CUI inspections are normally conducted at the same interval as, and in conjunction with, atmospheric corrosion inspections unless a more frequent inspection interval is dictated based on the risk analysis performed as described in the CUI Equipment Degradation Document (EDD). This risk analysis considers such factors as operating environment, service, age, and prior inspection results. All piping in contact with insulation shall be inspected, and no exceptions should be considered because of material used (e.g. stainless steel, carbon steel) or the diameter of the piping. Insulated piping inspections are typically visual inspections that may be complemented with non-destructive test (NDT) methods.

Scheduling of insulated piping corrosion inspections will be administered within SAP PM.

Piping that is covered with insulation will be identified and inventoried. The list of piping should include piping temporarily insulated for winterization. Piping that is temporarily insulated for winterization should be inspected when temporary insulation is removed, not exceeding regulatory intervals.

Insulated inventory shall be physically validated once a year.

For facilities governed by 49 CFR Part 195.583 (Liquids) or 49 CFR Part 192.481 (Gas), inspections will be performed at a maximum interval of 3 years, not exceeding 39 months, or as required by other regulatory agencies.

Anomalies or coating deterioration found during the inspection process that require permanent repair or recoating to piping and are not immediately addressed shall be included on the area Integrity Conditions List (ICL) and addressed by the Local Risk Management Team (LRMT). A determination should also be made as to whether anomalies qualify as Safety-Related Conditions. If additional guidance is required to address problems found, requests for assistance should be directed to the Program Steward, Field Engineering, and/or Subject Matter Expert (SME).

5.1.4 Internal Corrosion Control Program

EMPCo has developed an Internal Corrosion Control Program that provides a guideline to evaluate risk factors and control internal corrosion within its pipelines and to document the monitoring and mitigation efforts associated with the program's activities. Internal corrosion control committees, which manage corrosion control of assets in their respective areas, operate in all geographic regions of EMPCo.

Field Operations and Pipeline Integrity Engineers (PIEs) evaluate internal corrosion risk factors during scheduled Integrity Management Program (IMP) assessments. Risk factors are incorporated into the Threat Identification and Risk Assessment (TIARA) process.

SMEs will assist, as necessary, with the recommendation of tests to determine corrosivity, selection of mitigation systems (inhibitor, oxygen scavenger, biocide, pigging, etc.), selection of monitoring equipment, and evaluation of the effectiveness of the mitigation efforts.

Types of programs available for monitoring and preventing internal corrosion include, but are not limited to:

- Coupon monitoring
- Pipeline pigging
- Chemical inhibition
- Water analysis
- Pigging debris analysis

While it is important to control all forms of corrosion, it is necessary to first determine the cause of corrosion. General corrosion is often best prevented with an active pigging program and/or corrosion inhibitor injection. Pitting corrosion is often attributed to microbiologically influenced corrosion (MIC), most often caused by the presence of sulfate reducing bacteria (SRB), or acid producing bacteria (APB), which are optimally treated through a combination of regular pigging and biocide application.

Pipeline systems should be reviewed annually when IMP work indicates internal corrosion is a risk factor. Field Operations should determine how frequently pipelines that are not included in the IMP should be reviewed.

Based on the internal corrosion risk factors identified, an internal corrosion mitigation strategy should be developed and documented.

If corrosion inhibitors are used to mitigate internal corrosion, the corrosion coupons or other monitoring equipment used to determine the effectiveness of the inhibitors in mitigating internal corrosion must be examined at least twice each calendar year, but with intervals not exceeding 7-1/2 months per 49 CFR Parts 195.579(b) (Liquids) and 192.477 (Gas).

Corrosion mitigation efforts may include mechanical measures (running pigs) and/or chemical treatment.

Pigging should be considered to keep water from accumulating in low-lying sections of the pipeline, allowing the formation of corrosion cells.

Chemical treatment of the facilities may be utilized to eliminate the causes of internal corrosion. Possible treatment includes:

- The injection of biocides
- The injection of chemical inhibitors
- The injection of chemical oxygen scavengers

Corrosion coupons or other approved methods may be used to test the effectiveness of internal corrosion mitigation efforts (mechanical and/or chemical). Trends should be analyzed by the Field Steward, with help from SMEs or industry experts, if required, to determine whether adjustment of the mitigation program is necessary. Corrosion coupon results and other test records should be maintained by a Field Steward.

The control of internal corrosion in an existing pipeline must be analyzed individually and a specific mitigation program established. Mitigation methods may include pigging, chemical treatment, and design.

5.1.5 Shorted Casings Program

EMPCo has developed a Shorted Casings Program for identifying, testing, monitoring, mitigating, and documenting metallically shorted casings. It lists acceptable test methods for determining if a metallic short exists between the carrier pipe and the casing. This document is intended to ensure compliance with applicable regulations.

This procedure applies to personnel involved in corrosion control and the inspection and testing of suspected shorted casings as identified during cathodic protection surveys. All personnel shall have the appropriate OQs for performing this type of work. Possible associated OQ-covered tasks are Measuring Structure to Soil Potentials, Determining Shorted Casing, Inspecting/Monitoring Shorted Casings, and Repairing Casings.

When CP surveys are conducted, potentials are to be taken at all known cased locations. 49 CFR Parts 192.467(d) (Gas) and 195.575(c) (Liquids) require that casings be monitored for electrical isolation from the carrier pipe.

In compliance with existing state and federal Department of Transportation regulations, EMPCo's Shorted Casing Program is as follows:

- All known casings will be monitored annually for electrical isolation from the carrier pipeline.
- A casing will be suspected to be metallically shorted to the carrier pipe if the difference between the casing-to-soil potential and the pipe-to-soil potential is 100 mv or less
- Existing casings will be removed when feasible.
- Where it is not feasible to remove the casing, metallic shorts will be cleared, filled with high dielectric filler, or monitored for hydrocarbon vapors.
- In-Line Inspection tools may be used to detect corrosion of carrier pipe inside casings and to identify locations of casings. Guided-Wave Ultrasonic Testing (GWUT) is another method used for detecting corrosion of carrier pipe inside casings.
- A complete record of these tests, growth rate calculations, and any remedial actions taken shall be kept by each Area. All known casings that are not monitored annually for electrical isolation must be listed on a Casings Not Monitored for Electrical Isolation Form. The form must be completed annually and ascended from the Technician through the chain of command to the Area Manager for approval. An action plan will be developed to facilitate monitoring for electrical isolation.

For jurisdictional liquid pipelines that are metallically shorted to casings, options include:

1. Attempt to clear metallic short, if practical.

2. Fill the carrier pipe/casing annulus with high dielectric filler, which provides a corrosion-inhibiting environment. Once the annulus has been filled, testing or monitoring for a shorted condition is no longer required.
3. If options 1 or 2 (above) are impractical and the risk of a corrosion related failure is minimal as determined by condition and operation of the pipeline, EMPCo may choose to monitor the casing for leaks by measuring hydrocarbon vapors at the casing vent at intervals not exceeding 7½ months, but at least twice each calendar year until such time as options 1 or 2 (above) become practical.
4. ILI may be used to identify cased crossings and detect corrosion inside casings in accordance with EMPCo's FIMMS In-Line Inspection Program document and EMPCo's IMP Manual guidelines. GWUT is another method used for detecting corrosion inside casings.

All confirmed metallically shorted casings and recommended repairs or remediation shall be included on the Area Integrity Conditions List. Where practical, all metallic shorts will be removed, cleared, or filled with high dielectric filler. If ILI or GWUT indicates no metal loss in a metallically shorted casing, the casing may be excluded from the Area ICL. Until metallically shorted casings are removed, cleared, or filled, they will be monitored for hydrocarbon vapors regardless of ILI or GWUT status. A FIMMS Field Steward shall keep all records of the monitoring and repairs of metallically shorted casings in his/her area. Repair of metallically shorted casings shall be scheduled in SAP PM.

5.1.6 Atmospheric Corrosion Inspection Program

EMPCo has developed an Atmospherice Corrosion Inspection Program that provides a guideline and describes the responsibility for performing and documenting routine atmospheric corrosion inspections of piping exposed to atmosphere within the scope of the DOT and other state and local agencies, American Society of Mechanical Engineers (ASME) piping codes, and API documents. Atmospheric corrosion inspections are typically visual inspections that may be complemented with NDT methods.

This program applies to the EMPCo Inspector and/or contract personnel who perform visual external inspections. This procedure is intended for use by personnel responsible for the inspection and documentation of existing piping facilities exposed to atmosphere. All personnel involved in the inspection, testing, evaluation, and repair of piping exposed to atmosphere shall have the appropriate OQs. Possible associated OQ-covered tasks are Inspecting Exposed Pipe and Performing Atmospheric Surveys, Coating or Recoating Pipe, and Determining Wall Thickness.

Inspection includes examination for signs of leakage, mechanical damage, coating failure, corrosion, or cracks in butt and fillet welds, sagging pipe or failed supports or hangers, excessive vibration, distortion, failed or damaged thermal insulation, and seepage from weep holes in reinforcement pads.

Scheduling of atmospheric corrosion inspections will be administered within SAP PM. All locations or sites to be inspected will be entered into SAP PM. The inspection schedule and frequency will be entered according to the intervals listed below:

- Onshore pipelines every 3 calendar years not to exceed 39 months for facilities regulated by DOT and its state agents such as CSFM, LDNR, and TRRC.
- Except for portions of pipelines in soil-to-air interfaces, operators will not have to protect from atmospheric corrosion any pipeline for which the operator demonstrates by documented test, investigation, or experience that corrosion will: (1) Only be a light surface oxide, or (2) Not affect the safe operation of the pipeline before the next scheduled inspection.

Periodic pipe-to-soil potential surveys shall be conducted on each underground facility that is cathodically protected at least once each calendar year at intervals not exceeding 15 months to determine if cathodic protection is adequate. However, if tests at those intervals are impractical for separately protected short sections of bare or ineffectively coated pipelines, testing may be done at least once every 3 calendar years, but with intervals not exceeding 39 months.

For piping exposed to atmosphere and operating at a stress level of more than 20% of the specified minimum yield strength (SMYS), the following locations are recommended for 1 to 3 year inspection intervals, not to exceed 39 months.

- For piping exposed to moist salt-laden atmosphere such as:
  - Piping adjacent to bays
  - Piping in the vicinity of brine surface pits
- For piping frequently operated at temperatures lower than the dew point of the atmosphere (sweating service) such as:
  - Piping with refrigeration systems
  - Piping downstream of pressure reduction and flow control valves
- Two years for onshore piping which is operated in moist salt laden atmospheres such as:
  - Onshore piping in coastal areas
  - Onshore piping not in coastal areas but near rivers and major bodies of water

Anomalies found during the inspection process that require permanent (welded or composite) repair to piping and are not immediately addressed shall be included on the area Integrity Conditions List and addressed by the Local Risk Management Team. A determination should also be made as to whether anomalies qualify as Safety-Related Conditions.

5.2 Right-of-Way

5.2.1 Right-of Way-Survey Program

EMPCo has developed a Right-of-Way Survey Program that provides a guideline to plan, execute, and manage results of right-of-way (ROW) Surveys. For the purposes of this document, ROW Surveys include pipeline centerline mapping and depth of cover surveys, close-interval surveys, AC potential surveys at cathodic protection test stations, alternating current voltage gradient (ACVG) or direct current voltage gradient (DCVG) surveys, encroachment surveys, verification of foreign line crossings, verification of exposed pipe, and verification of water crossings.

The purpose of conducting ROW Surveys described below is to provide high quality data for the Data Integration process, which is used to identify pipeline locations requiring further attention in the form of repairs and/or further investigation for proactive risk reduction.

<u>Pipeline Locate & Depth of Cover (DOC) Survey</u>

To facilitate verification of the pipeline locate survey, the post processed field data and differential correction report should be delivered with the modeled centerline (if applicable).

The objective of the DOC survey is to establish a DOC profile to improve risk awareness with respect to third party damage and to assist One-Call responders in locating the pipeline prior to and during excavation.

Under typical ROW conditions, the depth and position of the surveyed pipeline will be identified and recorded within 150 foot intervals and at the locations in the table below:

Feature Type	Location of Data Collection
Paved Road	Shoulders and centerline of ditches on both sides
Unpaved Road	Centerline of road and centerline of ditches on both sides
Railway	Toe of each railroad ballast and centerline of ditches on both sides
Ditch	Centerline or bottom of ditch
Creek	Center or bottom of creek
River	Within 6 feet of each shore line
Fences/Encroachments	At crossing location
Pipe/Utility Crossings	At crossing location
AGMs for ILI	At location
Pipe Appurtenances	Valves, above ground pipe, test stations, rectifiers, etc.
Encroachments	As described in this document

Survey contractor will notify the IPE representative every month of all probed depths of cover. The IPE representative shall notify the LRMT Leader of any depths 36” or less.

Close-Interval Survey
The objective of the CIS survey is to determine the adequacy of CP levels along the surveyed pipeline.

CIS will be conducted in accordance with the FIMMS Close Interval Survey Program.

EMPCo’s on-site ROW Survey representative will be notified if the following conditions are identified:

- Polarized potential(s) more positive than -600 mV is measured
- “On” and “off” potentials converge (within 20 mV)
- Polarized potential(s) more negative than -1200 mV is measured
- “Off” potentials are more negative than “on” potentials

AC Potential Survey
The objective of the AC potential survey at CP test stations is to determine whether shock hazards exist.

EMPCo’s on-site ROW Survey representative will be notified if the potential(s) is greater than or equal to 15 volts.

Alternating Current Voltage Gradient or Direct Current Voltage Gradient Survey
The objective of the ACVG or DCVG survey is to detect coating holidays at accessible areas along the pipeline.

The following conditions shall be identified in the final report provided by the survey contractor:

- Greater than 65% IR (DCVG)
- Greater than 70 dBµV (ACVG)
- Greater than or equal to five (5) indications per 100 feet using a sliding 100-foot method

Encroachment Survey

The objective of the encroachment survey is to detect obstructions near the surveyed pipeline and to determine if risk mitigation action is warranted.

Following is a list of encroachments that will be identified and photographed from multiple angles. Photographs must include orientation of surveyed pipeline. A description of the encroachment with GPS coordinates, including the offset distance to the surveyed pipeline, will be documented. An encroachment is defined as follows:

- Trees with potential to damage the surveyed pipeline, classified as:
  - Less than 5' from pipeline - all trees, woody shrubs, and woody vegetation
  - 5' – 10' from pipeline – trees greater than 8" in diameter at chest height
  - 10' – 14' from pipeline – trees greater than 36" in diameter at chest height
- Ground penetrations such as fences, anchors, structures/foundations, etc. that are directly over the pipeline that may be in contact with the pipeline.
  - Driveways – only where pipeline DOC is less than 3'
  - Fences – only where fence post is less than 1' from pipeline

Verification of Foreign Line Crossings

The objective of this process is to verify foreign line crossing locations along the pipeline and to determine if risk mitigation action is warranted. Verification is completed through observation of foreign pipeline markers and other aboveground indicators.

EMPCo will provide the location of the foreign line crossings prior to the survey. During the survey, the contractor will identify locations of foreign line crossings with sub-meter GPS coordinates using datum and equipment specified in this document. If a new foreign line crossing is identified, the ROW Survey contractor must inform the corrosion technician immediately.

Verification of Exposed Pipe

The objective of this process is to verify all pipeline exposures along the pipeline to assure that the required inspections are occurring and to determine if risk mitigation is warranted.

EMPCo will provide the most recent completed Atmospheric Corrosion Inspection documentation prior to the survey. During the survey, the contractor will identify all pipeline exposures with sub-meter GPS coordinates using datum and equipment specified in this document.

Any exposed pipe that does not seem to be intentional shall be reported immediately to EMPCo's on-site ROW Survey representative.

Verification of Water Crossings

The objective of this process is to verify all water crossings along the pipeline.

EMPCo will provide a list of known water crossings prior to the survey. During the survey, the contractor will identify water crossings with sub meter GPS coordinates taken at each high bank of the channel using datum and equipment specified in this document. Photos will be taken of the crossing, upstream and downstream of the crossing, and on both sides of the banks. Any abnormal conditions associated with the crossing will also be photographed.

Any water crossings found during inspection that are not on EMPCo's inventory of known water crossings shall be reported to EMPCo's onsite ROW Survey representative. Sub-meter GPS coordinates taken at high banks and photographs shall be provided to EMPCo's on-site ROW

Survey representative who shall contact the Water Crossing Team as soon as practical following receipt of the information.

The Program Steward will work with Local Risk Management Teams to develop a ROW Survey plan. Factors such as historical CP performance, number of years since prior surveys were conducted and survey results, ILI results, expected condition of the pipeline coating, population density, and environmental impact of a potential failure may be considered when developing a survey plan. Remedial action that may be necessary as a result of the ROW Survey should be considered when developing cost estimates for budgeting.

Upon receipt of draft data, a meeting will be held with the respective operating Area to review survey results and develop a remedial action plan to address pipeline locations requiring further attention in the form of repairs and/or further investigation. Participants in the meeting shall include key members of the respective LRMT, including the Area ET/CT, an IPE representative, and a survey contractor representative. Progress on the remedial action plan shall be stewarded categorically by the LRMT. Data will be finalized following the meeting to develop a remedial action plan.

5.2.2 Navigable Waterway Crossing Inspection Program

EMPCo has a Navigable Waterway Crossing Inspection Program that describes the inspection and documentation requirements associated with EMPCo's navigable waterway crossings. The Program is intended to provide guidelines for ensuring compliance with applicable regulations. The objective of the Program is to effectively evaluate navigable waterway crossings to determine integrity status and prevent and/or mitigate potential hazards to navigable waters.

A database containing information about EMPCo's navigable waterway crossings is populated by Field Stewards and maintained on a shared drive by Program Stewards. The database contains a list of each crossing, along with information showing when it was last surveyed and when it is scheduled to be surveyed again. All crossings to be inspected will be entered into SAP PM.

Field Operations maintains a list of navigable waterways that are subject to inspections not to exceed 60 month intervals. All personnel involved in navigable waterway crossing inspection shall have the appropriate OQs. Possible associated OQ covered tasks are Line Locating, Placing/Maintaining Line Markers, and Inspecting Navigable Waterway Crossings. All personnel shall also be familiar with the requirements of EMPCo Water Crossing Data Collection Guide. Survey work shall be conducted under the guidance of a certified Professional Surveyor. Qualification is typically met by being a Registered Professional Land Surveyor (RPLS).

Regulatory Inspection Requirements:

- Navigable waterway crossings must be inspected at intervals not exceeding five years from the date of last inspection - 49 CFR Part 195.412(b) (Liquids)
- The inspection and evaluation shall determine if there is adequate cover over the pipeline and determine the condition of the crossing and whether there is active erosion/sedimentation occurring that could cause a problem before the next scheduled inspection

A Field Steward informs the Area Supervisor of priority crossings. Priority crossings are those that are suspended, exposed, without adequate cover relative to the rate of active erosion/sedimentation, and are considered in jeopardy of damage by environmental forces from navigation, ice, floodwater, debris, vandalism, etc.

The crossing shall be re-inspected within one (1) year of remedial action, including remedial action taken on a trestle.

5.2.3 Right-of-Way Maintenance Program

EMPCo has developed a Right-of-Way Maintenance Program that describes the requirements for maintaining rights-of-ways and pipeline corridors so that EMPCo may maintain its reputation as a good corporate citizen in the communities in which it operates. This program provides guidelines for maintenance of ROWs so that pipelines and other facilities may be safely accessed for maintenance, operations, and emergencies.

All personnel involved in ROW maintenance shall have the appropriate OQs. Possible associated OQ-covered tasks are Patrolling Lines - Air, Vehicle, or Foot and Line Locating, Placing/Maintaining Line Markers.

Where applicable, mowing shall be performed to maintain the ROW in accordance with applicable local ordinances and regulatory requirements and to allow ROW surveillance by the chosen method (air, vehicle, or foot).

In swamp or other inaccessible areas where mowing is not feasible, hand cleaning of fence lines and road crossings may be sufficient for adequate ROW access and inspection.

Below are the minimum expectations of an effective ROW maintenance program:

- Cutting and removal of brush and trees from the ROW
- Prevention/removal of overhang of trees which would prevent aerial surveillance of the pipeline(s)
- Removal of trash and debris from the ROW
- Brush, grass, and trees are maintained at heights that allow for access and surveillance of the ROW by the chosen method
- Pipeline location is clearly and accurately marked with pipeline markers and signs
- Casing vents shall be painted for visibility and corrosion protection
- Grass shall be maintained at short lengths or sprayed with approved weed control chemicals around appurtenances such as fence posts, pipeline markers, valves, and valve guards, etc.
- Grass shall be maintained at short lengths around cathodic protection rectifiers, bond boxes, test stations, etc.; care should be taken not to paint over the test lead terminal from which the readings are taken.

5.3 Process Equipment Program

EMPCo has a Process Equipment Program that outlines the requirements for EMPCo's inspection of process equipment. Process equipment is defined as pressure vessels, heat exchangers, fan coolers, furnaces (heaters), flare systems or other equipment as designated by field stewards and subsequently added to this document. The objective is to ensure process equipment performs its intended function safely, efficiently, and reliably. The program should ensure that the inspection of process equipment is performed uniformly throughout EMPCo. These procedures apply to EMPCo personnel and contracted outside personnel performing the inspections.

As a minimum, an inspection should determine if the equipment is in an acceptable condition to safely continue operations. It should determine if there is reason to remove the equipment from normal service due to mechanical failure, safety, or environmental hazard.

EMPCo policy is to perform external, internal, or on-stream inspections on all vessels included in this program. The following guidelines are in accordance with API 510 and API 572. As provided in API 510, on-stream inspection is allowed in place of internal inspection under the unique circumstances of EMPCo facilities.

Deficiencies identified during the inspection shall be forwarded to a Field Steward. The deficiency shall be reviewed with other internal personnel and the Area Supervisor to determine the corrective measures or steps needed to resolve. If deficiencies are of the nature requiring additional support or technical guidance they may be directed to engineering, other outside experts, or a Program Steward for resolution assistance. It is the responsibility of Field Stewards to ensure close out of corrective actions.

5.4 Tank Inspection Program

EMPCo has developed a Tank Inspection Program that serves as a guideline for EMPCo aboveground storage tanks (AST) for both Pipeline and Distribution facilities.

This program has been developed to ensure that AST structural inspections and associated documentation are performed in accordance with the API Standard 653 – Tank Inspection, Repair, Alteration, and Reconstruction. This standard covers steel storage tanks, built to API 650 and, its predecessor, API 12C. It provides minimum requirements for maintaining the structural integrity of such tanks. This program addresses the inspection requirements and intervals for ASTs outlined in Section 6 of API STD 653.

The goal of this program is to bring continuity to the inspection process and reduce the probability of leaks from storage tanks to the environment. The guidelines set forth in this program apply to EMPCo and/or contract tank inspection personnel and are intended for use by qualified and/or API certified personnel responsible for the inspection and documentation of AST facilities.

Scheduling of required AST inspections will be administered within SAP PM, Action Tracker, or other scheduling tool and be maintained by a local Field Steward. These scheduling tools will ensure that adequate controls are in place to manage and maintain required inspection intervals.

The inspection schedule and frequency will be entered according to the intervals listed below, unless regulatory requirements or previous inspection reports indicate that an earlier inspection must be conducted. Inspection frequency shall not be exceeded, unless an extension meets the criteria listed in API STD 653, and is confirmed by a Tank Maintenance Specialist (TMS) or Engineering Tank Specialist (ETS).

At least monthly, Operations personnel shall perform a routine in-service inspection of each tank. The intent of the inspection is to monitor the tank's exterior surfaces by close visual inspection from the ground. Personnel performing the inspection should be looking for evidence of leaks; shell distortions; signs of settlement; corrosion; and the conditions of the foundation, paint coatings, insulation systems, and appurtenances.

At least once per year, but not to exceed fifteen months between inspections, all DOT regulated tanks shall be inspected by a DOT OQ qualified Tank Inspector. Personnel performing this inspection will perform a more comprehensive/close-up inspection of the physical tank components.

Where exterior tank bottom corrosion is controlled by a cathodic protection system, periodic surveys and inspection of the system shall be conducted in accordance with API 651.

- Bi-Monthly, not to exceed 2 ½ months, on rectifiers and impressed current sources
- Annual surveys, not to exceed 15 months, of structure soil potential

API 653 requires a visual external inspection by an Authorized Inspector who is certified in API 653. This inspection must be conducted every 5 years or at the quarter corrosion rate life of the shell, whichever is less. This inspection can be conducted in-service.

API 653 requires that tanks be given an internal inspection by an Authorized Inspector who is certified in API 653. This inspection is primarily conducted to ensure that the bottom is not severely corroded and leaking. The inspections must be conducted, at intervals defined in API 653 section 6.4.2.1. The frequency for an internal out-of-service inspection is generally based as follows:

- At least every 20 years if the corrosion rate is known, unless the bottom minimum thickness will be less than required at the 20 year interval
- Within 10 years if corrosion rates are unknown

Deficiencies found during inspections shall be forwarded to and addressed by a Field Steward, with input from the Facility Supervisor, and corrective measures must be implemented to resolve the problem.

If deficiencies found are of a nature that requires technical or regulatory guidance, requests for such guidance should be directed to a Program Steward, TMS, Engineering, and/or Environmental Advisors.

5.5 Damage Prevention Program

EMPCo has developed a Damage Prevention Program that describe the minimum requirements for aerial right-of-way inspections to ensure EMPCo remains in compliance with applicable regulations and satisfies local requirements. Furthermore, these procedures are intended to assist EMPCo in identifying ROW encroachments, impending work near its facilities, and detection of pipeline leaks.

The primary method for inspecting rights-of-way is aerial patrol at regularly scheduled intervals. DOT 195.412(a) requires inspection twenty-six (26) times per year at intervals not exceeding three weeks.

The Pilot/Observer shall report all observations in accordance with the following three categories. If no hazards are observed during a flight, the Pilot/Observer should indicate on the patrol report "No Reportable Activity on Right-of-Way".

- Imminent Danger - Pilot/Observer shall proceed immediately to a safe location (if not already in one) as determined by him/her and report items that present an imminent danger to the appropriate EMPCo representative. These items consist of, but are not limited to, the following list:
  - Any suspicion of a leakage or break in the pipeline (spills, stains, film or sheen on water surface, etc.)
  - Any dirt moving/excavation or boring equipment whether active or idle (includes farm tractors using plow type equipment) on the ROW
  - Fires of any nature on or adjacent to an ExxonMobil ROW or facility
  - Storm or other damage to any ExxonMobil facility/equipment
  - Any active logging operation in the vicinity of the ROW

- Potential Danger - The following list of items observed near the ROW, shall be reported by the Pilot/Observer when he/she deems conditions are safe enough to do so along the normal route of flight, or at the next intended point of landing (whichever comes first):
  - Dirt work/construction
  - Building construction
  - Surveying activity that may indicate plans to do work
  - Construction or maintenance of pipeline or other facilities whether operated or supervised by ExxonMobil or others
  - Ditching (excavation) for any reason
  - Construction of drainage, irrigation, or canals
  - Clearing of timberland
  - Road grading (or maintenance of existing roads)
  - Vessel under tow
  - Any other activities that may damage the pipeline
  - Camps, recreational vehicles (RVs), mobile homes, or portable buildings

  - Where telephone lines or power lines follow pipelines, report broken poles or cross arms, downed wires, burned poles, and broken branches of trees on pipeline which may disrupt service.
  - Report condition at river and creek crossings such as debris collection, erosion, or sagging or exposed pipelines
  - Oil or excessive water buildup on top of external floating roof tanks
  - Waste oil or salt water pits or drainage on line
  - Report any activity on ROW that might cause hazards or restrictions to the operation of the pipeline

- ROW/Marking Conditions - The following list of items shall be reported by the Pilot/Observer to the appropriate EMPCo representative. Following the initial report, the aerial patrol service provider will only report repeat items on a quarterly basis (February, May, August, and November) until the item is satisfactorily resolved.
  - Overhanging tree growth preventing effective aerial patrol inspections
  - Rutting caused by machinery crossing ROW
  - Markers down
  - Erosion over pipelines
  - Excessive vegetation
  - Deposits of debris on ROW
  - Fallen trees in the ROW
  - Report vandalism damage to telephone, fences, or other facilities
  - Report open fences or gates down
  - Dirt stockpiled on or near the ROW

5.6 Integrity

5.6.1 Hydrostatic Pressure Testing Program

EMPCo has a Hydrostatic Pressure Testing Program and Hydrostatic Test Manual that outlines the minimum requirements for hydrostatically testing EMPCo facilities. Hydrostatic pressure testing is important to establish an integrity level for the existing condition of facility piping. It is also a requirement of the Department of Transportation, Office of Pipeline Safety (OPS), and state regulatory agencies. Hydrostatic pressure testing provides a means to ensure compliance with applicable DOT and State Regulations and OIMS requirements, and to provide information to support risk assessments and risk management decisions.

Hydrostatic pressure testing is a requirement to establish initial pipeline integrity in DOT Regulation Title 49 CFR Part 195.302 and Part 192.503, Pressure Testing General Requirements, for liquids and gas lines respectively. Hydrostatic testing is also addressed as a continual integrity assessment method in 49 CFR Part 195.452 and Part 192.937, Pipeline Integrity Management in High Consequence Areas. When an operator chooses to use hydrostatic testing as its integrity assessment tool to comply with integrity management within a High Consequence Area (HCA), the quality and effectiveness of the pipeline corrosion control program must be demonstrated. This includes review of data such as release history, cathodic protection annual survey results, pipeline current demand, results of cathodic protection close interval survey data, coating integrity, results of open hole reports, and internal corrosion monitoring and inhibition results.

Hydrostatic pressure testing is applicable to the following:

- Newly constructed steel pipeline systems and additions to existing pipeline systems.
- Existing steel pipeline systems that are relocated, replaced or otherwise changed. This includes cases in which there is 1) an increase in established operating pressure, 2) a service change such as gas to liquid or Hazardous Liquid to Highly Volatile Liquid service in which the existing test does not meet the requirements of the new service.

- Existing pipeline systems to re-establish system integrity or to maintain current operating pressures in accordance with regulatory requirements.

Any new or changed pipeline system shall be properly tested to prove system integrity before being placed in service. Qualified personnel shall perform all testing in accordance with EMPCo standards and specifications. Any failures that occur during pressure testing must be promptly repaired and documented prior to resuming testing. Normally, the tested section of pipeline must be depressurized, and in some cases purged, prior to attempting repairs. The repairs and repair documentation must be in accordance with applicable codes and standards as well as Company requirements as detailed in the Facility Repair and Modification Manual.

5.6.2 In-Line Inspection Program

EMPCo has an In-Line Inspection Program that describes the minimum requirements for EMPCo in-line inspections. It provides general guidelines for the proper selection of devices used for in-line inspections of pipelines, ranging from simple "gauging plate" pigs to more sophisticated instrumented tools known as "smart pigs." These devices are utilized to detect anomalies (corrosion, defects, dents, etc.) in pipelines without the need to remove the pipeline from normal operating service.

The ILI Program provides a framework to ensure compliance with applicable Department of Transportation, State Regulations, and OIMS requirements, and to provide information to support risk assessments and risk management decisions.

The preferred integrity assessment method within EMPCo is ILI, which is used where possible. The base function for ILI tools are to detect corrosion anomalies and deformation anomalies.
ILI "smart pig" tools travel through the pipe and measure and record irregularities that may represent corrosion, cracks, laminations, deformations (e.g. dents, gouges, etc.) or other anomalies. Smart pigs are inserted into the pipeline at a location such as a valve or pump station that has a special configuration of pipes and valves where the tool can be loaded into a launcher, the launcher can be closed and sealed, and the flow of the pipeline product can be directed to launch the tool into the main line of the pipeline. A similar setup is located downstream, where the tool is directed out of the main line into a receiver, the tool is removed, and the recorded data retrieved for analysis and reporting. Smart pigs can use a combination of technologies such as caliper and magnetic flux leakage (MFL) functions in a single tool.

After the initial or preliminary survey results are obtained, either on site following the inspection run or within a few weeks, they must be reviewed and categorized so that the major anomalies are corrected according to highest risk prioritization. Additionally, 49CFR195.55, Reporting Safety Related Conditions and 49CFR195.452, Pipeline Integrity Management in High Consequence Areas, requires immediate repair or corrective/mitigative action(s) be taken for some anomaly conditions. In the gas code, the applicable sections are 49CFR192.949 and 49CFR192.933. Anomalies identified in the final internal inspection report must be addressed and corrected according to a defined repair schedule prioritized by risk. This repair schedule must also meet the special requirements for scheduling repairs in HCAs as defined in 49CFR195.452 and/or 49CFR192.933.

5.6.3 External Corrosion Direct Assessment Inspection Program

EMPCo has an External Corrosion Direct Assessment Inspection Program that describes the minimum requirements for EMPCo's ECDA inspections. It also provides guidelines for the proper selection of techniques used for ECDA inspections of pipelines. These techniques are utilized to detect potential integrity threats without the need to remove the pipeline from normal operating service.

This program provides the minimum requirements for compliance with applicable Department of Transportation, State Regulations, and OIMS requirements, and to provide information to support risk assessments and risk management decisions.

The ECDA methodology is a four-step process that requires the integration of data from multiple indirect field inspections and from direct pipe surface examinations with the pipe's physical characteristics and operating history. The four steps of the process are:

1. Pre-Assessment
2. Indirect Inspection
3. Direct Examination
4. Post-Assessment

Each step of the ECDA Process should validate the process that precedes it such that confidence is increased during each step of the process and high confidence is achieved as a result of assessment by ECDA. This could mean that an ECDA project could come completely to the end of the Post-Assessment phase of the project and ultimately fail to produce adequate confidence and as such be rejected as a valid integrity assessment.

An ECDA program that exceeds the requirements of NACE Standard Practice 0502- 2010, Pipeline External Corrosion Direct Assessment can be used in lieu of the DOT hydrotest or In-Line Inspection requirements, and is an excellent option if a pipeline cannot tolerate any sizable amount of downtime, as would be the case of a hydrotest, and is not smart pig compatible (and cannot be feasibly modified to become smart pig compatible) such as a dual diameter line or very short pipeline segment.

After the initial program results are obtained and reviewed following the completion of the ECDA study, any major anomalies can be investigated with further investigative excavation and corrected according to the highest risk prioritization.

Whenever a covered pipeline is uncovered, a company representative at the site must thoroughly inspect the pipe. When there is evidence of corrosion, the person responsible for corrosion matters must be notified. The pipeline should then be examined circumferentially and longitudinally, on both sides of the affected area, until good pipe is visible. The responsible person investigates the extent of corrosion and determines if cathodic protection levels are adequate.

5.6.4 Low Flow Conditions

EMPCo recognizes low flow piping as any line with a flow rate less than 3 feet per second (FPS). Lines where the flow is less than 3 FPS allow pockets of water to drop out of entrained water in low areas thus providing optimum conditions for microorganisms like sulfate-reducing bacteria to grow, thus increasing the corrosion rate in those lines. At no or low flow conditions, low points in the piping/fittings, the bottom of a non-concentric reducer, etc., can create a condition for very high corrosion rates. Stagnant bacteria growth is dependent on velocity. Regular flushing of these no or low flow lines may help to flush out the bacteria but that is a difficult thing to accurately monitor, and very time consuming for Operations.

The corrosion associated with crude piping that is stagnant with no or low flow rates less than < 3FPS are identified as "dead legs" which should be mitigated.

When dead legs are thought to exist, there are several methods available to help mitigate these highly corrosive conditions and are listed as the following:

- For pipe segments that are not currently used but might be in the future, mothballing could be an acceptable choice. The segment would need to be cleaned, dried, and then properly sealed with an inert atmosphere. Pressure gauges at the mothballed segment could be used to monitor the presence of the inert atmosphere, e.g. nitrogen. If additional preservatives are used for the piping, flanges, pumps, etc., they must be carefully selected. There have been cases where some of these preservatives have actually promoted corrosion because water was present in the preservative.

- Periodic flushing of the segment in order to clean out "loose" deposits. Periodic flushing can be used to clean the segments and disrupt bacterial growth and works fairly well when the deposits are loose. In order to achieve a more effective flushing, the segment flushing needs to be surged or transition/turbulent flow needs to be used. Therefore, the flow rate should not be held constant but varied by opening and closing the valve. This surging will keep the solids moving.

- Pigging of the segment to achieve a more aggressive cleaning than just flushing. For adherent solids, a more aggressive method may be needed. Spherical pigs are typically used to dewater a pipe segment while versions of foam pigs are usually used for solids removal. In some piping cases both types of cleaning pigs might be needed to achieve the required level of cleanliness. If possible, a flow rate of 3 FPS or more is strongly desired in order to remove thick biofilms. The frequency of using these cleaning pigs would depend on the amount of water/deposits generated in the specific system.

- Chemical treatment of the segment with the possible use of biocides, corrosion inhibitors, and oxygen scavengers. Similar to wet layups of pipelines after hydrostatic testing and prior to actual startup, chemical treatment can be used to mitigate corrosion in stagnant areas. Typical recommendations from reputable chemical companies include additions of biocide and a corrosion inhibitor (dependent on the residence time of the water in the piping segment). In some cases an oxygen scavenger is also recommended to reduce the amount of corrosion products that accumulate in the piping prior to the entrained oxygen being completely consumed.

6.0 Operations

Operation of facilities within established parameters and according to regulations is essential. Doing so requires effective procedures, structured inspection and maintenance programs, reliable critical equipment, and qualified personnel who consistently execute these procedures and practices.

Whenever any condition is discovered that could adversely affect the safe operation of the pipeline, efforts must be made to correct the condition before the next scheduled maintenance or inspection activity. If it is not feasible to correct the deficiency before the next scheduled maintenance or inspection due to long lead purchase items, then efforts must be made to correct the deficiency as soon as it is feasible.

6.1 Berth Operations

The primary reference for marine terminal operations is the Berth Operators Guide (BOG). The BOG has been adapted to EMPCo Marine Terminals through the addition of Sections 12 and 13. A copy of the BOG is maintained on the ExxonMobil Research & Engineering (EMRE) web site. The Terminal should have at least one hard copy at the dock.

The following procedures and reference materials are utilized for Marine Operations:

Procedure	Responsibility	Comments
Berth Operator's Guide	EMRE Marine Terminal Engineering	Copy maintained on EMRE Web Site. Terminal should have a hard copy at the marine dock.
BOG Section 12 and BOG Section 13	Local Terminal Superintendent	Section 12 of the BOG contains EMPCo exceptions/ adaptations to the BOG. This Section is revised as necessary by the Owner to reflect updates from EMRE. Each terminal has a unique Section 13 that reflects local terminal information and is updated by the Terminal Superintendent. Copy required at each marine terminal including posting at dock.

Marine Terminal Operations Manual	Terminal Superintendent	USCG required manual (33CFR 154-156); Copy required at each marine terminal.
Berth Operator's Training	EMRE, Local Terminal Management	EMRE Berth Operators Guide, EMRE Global Manufacturing Training (GMT) modules relevant berth operator training. Local berth operator familiarity training.
Vetting Manual	International Marine Transportation (IMT) / SeaRiver	Process for screening/vetting all tank vessels prior to arriving at terminals. Copy held by Owner.
Pollution Safety Advisor Manual (PSA)	SeaRiver	Procedures and criteria for use of PSAs and Person-in-Charge (PICs) at EMPCo Marine Terminals. Copy inserted in Section 12 of BOG.
International Oil Tanker and Terminal Safety Guide (ISGOTT)	Oil Companies International Marine Forum (OCIMF)	OCIMF manual relevant safety procedures, guidelines and industry best practices for marine tanker and terminal operations. Copy required at each marine terminal.

6.2 Terminal Operations

The primary reference for terminal operating procedures is the Terminal Operator's Guide (TOG). TOGs must be reviewed annually and Terminal Superintendent or Designee should document these reviews in the revisions pages at the end of the TOG. All updates must be posted on EMPCo's Reference Library.

Each terminal or storage facility will maintain its own TOG and must have content covering the operations as outlined in the Terminal Operating Guide Outline Requirements posted on the Reference Library in TOG. Terminal Operations References is also provided and posted in the Reference Library.

6.3 Pipeline Operations

The primary reference for pipeline operating procedures is the Local Operating Instructions (LOI) for each field location and the Operations Control Center (OCC) Operating Instructions (OI) for all pipeline systems. The LOIs are maintained at each field facility, pump station, meter site, etc. The OCC OIs are maintained in the OCC. Both are also maintained on the EMPCo Reference Library.

LOIs typically address the following information:

- System Description
- Products Transported Through the System
- Product Description
- General Line Parameters
- Operations with Normal Conditions
- Normal Startup Procedures
- Normal Shutdown Procedures
- Abnormal Operations
- Typical Abnormal Operations
- Response to Abnormal Operations
- Response to an Unintended Valve Closure or Shutdown
- An Increase or Decrease of Pressure or Flow Rate Outside the Normal Operating Conditions
- Operations of any Safety Device
- Loss of Communication

- Other Malfunctions or Deviations from Normal Operations
- Emergency Conditions
- Notification of an Emergency Condition
- Emergency Conditions Indicated by Alarms and Analysis
- Safety Critical Procedures
- Fire
- Loss of Power
- Other Health/Safety/Environmental Issues
- Explosions
- Pipeline Leaks
- Line Startup after Emergency Conditions
- Facility Component Information & Operation
- Local - Remote Control
- Major Equipment
- Pump Unit Operation
- Storage Tanks
- Valve/Manifold Operation
- Tank Gauging (Auto/Hand)
- Meter Proving & Operation
- Measurement
- Gravitometers
- Alarm Conditions and Response
- Equipment Controls
- Status Information
- Alarm Information
- Data and Software Alarms

Pipeline operators are required to periodically review work performed by operator personnel to determine effectiveness of the procedures used in normal operations and maintenance and to take corrective action where deficiencies are found.

Once per calendar year, not to exceed 15 months between, Field Operations shall conduct a group review meeting in each location and document accordingly on either the DOT 195 & LOI/TOG Annual Review Form, or the Company Safety Meeting Minutes Form. The latter form should be used when the DOT Annual Review is held in conjunction with a Safety Meeting. Supervisors will review the various routine normal operations and maintenance work and related procedures (LPS/LPO, Work Permitting, LPSA, OIMS Assessments, or Near Losses) conducted during the prior year and discuss any items that may require further explanation. If possible deficiencies are identified, the Company will review the recommendations and if appropriate, effect corrective actions. Such actions could include a change in procedures, training, and/or individual employee counseling/training.

6.4 Operation Control Center

EMPCo operates its trunk line network of crude, refined product, and chemical pipelines from a central Operations Control Center which is located in Houston, Texas.

The OCC SCADA (Supervisory Control and Data Acquisition) System operates American pipelines with three EMPCo IRIS computers.

- First computer is designated as the primary in operation
- Second runs as a hot backup
- Third computer is OCC's link to applications for EMPCo shippers and is also used for in-house applications that rely on SCADA data to perform functions

The SCADA system was designed in such a manner that all remote locations connected to the OCC are routed via communications with 99.9% reliability. The hub sites are tested bimonthly by SCADA personnel based on SAP PM scheduling.

In conjunction with the hub sites, the SCADA system also has a Disaster Recovery Center (DRC) located in the EMPCo Facility Administration Building located in Corsicana, Texas. The DRC has been designed and located such that it could assume OCC operation within 6 hours of the decision being made to activate the DRC. The DRC computer is updated continuously via a data link to the primary OCC system in Houston. When activated, the DRC has the same control and surveillance functions as the OCC system. The OCC Department Manager may activate the DRC anytime OCC operations are interrupted and restoration of the system is estimated to take in excess of 6 hours. The DRC may also be activated in advance of a pending natural disaster that is believed to threaten OCC operations. In this situation, the DRC would run in parallel with the OCC until the decision is made to shut down the OCC.

Additionally, the Auxiliary Control Center concept of using company issued laptops to access the OCC SCADA system from an alternate location to monitor/control the pipelines, is available.

The Operation Control Center provides round-the-clock monitoring of startup and shut-in operations in various pipeline systems within the Company through remote sensors transmitting the information to its central location. The OCC is manned continuously for surveillance and control purposes. Each pipeline facility has local manual operating instructions which describe the normal, abnormal, and emergency operation of that facility.

Any and all emergency and abnormal operating conditions occurring in, or involving, the OCC will be reported to the Department Manager. As a proactive approach to handle potential emergency and abnormal conditions, EMPCo has developed a Business Continuity Plan. It is the OCC Manager's responsibility to initiate the BCP and the OCC Area Supervisor will supervise the implementation of the Plan.

The BCP was developed to aid EMPCo's Houston operating management in dealing with problems associated with the partial or total disruption of communication and supervisory control from the EMPCo OCC due to fire, acts of nature, equipment failure, and/or sabotage. It provides a procedure to be executed by the OCC and Field Operation units to ensure that EMPCo will be able to provide the necessary transportation service required by each of its shippers in the event the OCC is disabled

Experienced, well-trained people are essential for successful implementation of this BCP. Exercises are performed to check the effectiveness of the training and to test the plan. An ongoing training and exercise program will be carried out for each area. In addition to maintaining maximum familiarity with all aspects of the BCP, the training and exercise program is intended to provide members of the Area Leadership and Area Resource Teams with the basic knowledge, skills, and practical experience necessary to perform safe and effective business resumption operations in accordance with the BCP.

The OCC BCP DRC Training is "hands on" and consists of traveling to the backup control center in Corsicana, Texas, taking ownership of the selected consoles from the DRC, printing normal reports and sending pipeline commands. Upon return to Houston, a report is created that lists all personnel (EMPCo and contract) who participated in the test, what commands were sent, other functions completed while there (replacing OCC OIs with current sets, running inventory of needed supplies, etc.) and documenting any operation that was not performed at 100%.

7.0 Integrity Management

ExxonMobil is developing cutting-edge technology to enhance the effectiveness of its pipeline inspections. Specifically, the technology improves the ability to detect and characterize pipeline cracks, which are caused by corrosion or other factors such as original fabrication flaws, service conditions, or other external conditions. The technology is designed to enhance the capabilities of inline inspection tools, such as those that travel through pipelines, which could significantly increase the ability of inspectors to interpret and verify the data. This can improve EMPCo's ability to maintain pipeline integrity.

EMPCo has created an Integrity Management Program which was developed for compliance with 49 CFR 195.452 *Pipeline Integrity Management in High Consequence Areas*. Under 49 CFR 195.452, the U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration (PHMSA) requires operators to develop an IMP for hazardous liquid pipelines and carbon dioxide pipelines that could affect a HCA, including any pipeline located in a HCA, unless the operator effectively demonstrates by risk assessment that the pipeline could not affect the area. The State of Louisiana Department of Natural Resources, Office of Conservation administers federal IMP requirements as the governing body for Louisiana intrastate pipelines.

Requirements for compliance with 49 CFR 192 *Pipeline Integrity Management in High Consequence Areas (Gas Transmission Pipeline)* are also described in Appendix D of the IMP. While the two integrity management rules are separate, EMPCo follows common practices for both rules to the maximum extent possible. Appendix D identifies any instance where the gas rule requires additional or different practices.

The primary objective of the IMP is to provide a structure for identifying, prioritizing, and managing pipeline risk. This is done through the use of integrity assessments, data integration, repair, and reassessment as it relates to regulatory requirements and EMPCo standards. The IMP manual describes all processes required to successfully implement integrity management and specifically how IMP processes are documented, including IMP change management. It serves as the single compliance document for both federal and state integrity management requirements.

The IMP also provides guidance and instruction for timely and consistent IMP implementation. Program results are routinely monitored and stewarded by EMPCo Management and the findings are used for continuous improvement.

EMPCo is committed to conducting business in a manner compatible with the environmental and economic needs of all communities where it operates and in a manner that protects the safety and health of employees, those involved in EMPCo operations, EMPCo customers, and the public. Commitment to safety, health, and the environment is a longstanding ExxonMobil core value. Continuously improving all aspects of environmental performance is a key business objective that is monitored at every level. This commitment forms the foundation for the IMP and ExxonMobil's Operations Integrity Management System, which has been in place since the 1990s. OIMS is a formalized, structured system designed to address:

- Compliance with all applicable laws and regulations
- Design and operation of facilities to high standards
- Systematic identification and management of safety, health, and environmental risks

Aspects of OIMS directly address many of the IMP regulatory requirements. This manual further defines specific requirements for compliance with 49 CFR 195.452 and other federal or state regulations that govern integrity management, and in turn, the ongoing OIMS evaluation and improvement processes support continuous improvement of the IMP.

This manual prescribes the minimum requirements for permanent repair and modification of pipelines owned and/or operated by EMPCo. It is intended that these requirements shall be equal to or exceed the mandatory requirements of regulatory rules, codes, and standards.

It also prescribes the minimum requirements for repairing, lowering, rerouting, and hot-tapping pipelines owned and/or operated by EMPCo for the transportation of liquids and gases.

The IMP manual describes EMPCo integrity assessment methods, including ILI, hydrotesting and Direct Assessment. The processes and procedures for these methods are outlined in detail in the corresponding Facilities Inspection and Maintenance Manual documents.

- In-Line Inspection methods:
  - Caliper/Geometry
  - Magnetic flux leakage
  - Transverse flux inspection (TFI)
  - Ultrasonic crack detection (UTCD)
  - Ultrasonic wall measurement (UTWM)
  - Electro-Magnetic Acoustic Transfer (EMAT)
  - Inertial Navigation Survey (INS)
  - Other specialty tools as applicable (i.e. leak detection tools)
- Hydrostatic Pressure Test
- External Corrosion Direct Assessment and Modified ECDA

8.0 Training

ExxonMobil focuses on training employees in effective process safety procedures guided by OIMS, which serves as the foundation for consistently managing process safety risks at ExxonMobil.

Control of operations depends upon people. Achieving Operations Integrity requires the appropriate screening, careful selection and placement, ongoing assessment and proper training of employees, and the implementation of appropriate Operations Integrity programs.

The training, where relevant, includes operations and maintenance; Loss Prevention System; Safety, Security, Health, and Environment (SSHE) policies; SSHE leadership; communication and coaching; risk management; hazard identification; fundamentals of safety leadership; security awareness; safe driving; managing change; emergency preparedness and response; ergonomic awareness; hazard communication; food safety; regulatory compliance; cyber security; Industrial Control System Requirements (ICSR); and other job-specific training.

ExxonMobil has developed the Global Manufacturing Training Midstream Competency & Curricula Catalogue which defines the standard job requirements or Global Reference Roles (GRRs) applicable to Midstream.

Local roles are developed by the site referencing the GRRs where applicable. The differences in equipment and operation scope, organization, and contracting practices are also factored in. The differences are noted in a Mapping Reconciliation against the GRRs and are documented in an online based training system called WebCAT.

GMT/WebCAT is the primary tool to manage initial, ongoing, and refresher training for all personnel. It is also used to assess and document effectiveness of training and to identify deficiencies.

All GMT modules include online tests, practical demos, and/or interviews. Training conducted by vetted external parties may satisfy local training requirements.

Competency targets are developed by line management for the cluster and functions in EMPCo to meet operation needs. Targets are reviewed by cluster managers periodically to reflect changes in operations, organization, and demographics.

The key training focus areas stated in the system are mapped into the respective roles where relevant and available.

Local training requirements are an addition to the GRR requirement to address regional, cluster, and local needs in the form of Supplemental Modules assigned to each of the relevant local job roles.

Where required, Global modules may be localized and supplemental modules developed to meet site/country and regional needs. Cluster/Site Training Leader is responsible for reviewing and publishing localized and supplemental modules within AMFO/EMPCo as the Local Curricula Owner. Local and supplemental modules are reviewed with changes via the Management of Change process.

9.0 Notification List

CUSTOMER CONTACTS	

Emergency Contact List

Area Manager
Office
Cell

Area Supervisor
Office
Cell

First Line Supervisor
Office
Cell

Tech Leader
Office
Cell

ERST
Office
Cell

OCC
Office

10.0 History of Revisions

Rev. Date	Engineer	Typist	Description of Revision

APPENDIX G - Listing of Interconnect Agreements, Property Agreements and Amendments

G-1. LOCAP Tie-In Agreement Contract DE-FE93045 dated July 25, 2012 for LOCAP 24 inch and Plains 36 inch to the St. James Weeks Island Meter Station

G-2. Shell Tie-In at Bayou Choctaw (pending)

G-3. CAPLINE Tie-In Agreement dated December 3, 1987 for 30 Inch Tie-in to the St. James 30 inch Discharge 1 Header

G-4. Plains Marketing Tie-In Agreement Contract DE-AC96-06PO92433 dated May 10, 2006 for 36 inch to St. James 20 inch piping - Accelerator pumps and for a 36 inch connection to the Weeks Island Meter Station

G-5. LOCAP Land Lease Agreement and Draft Sub-Lease Template Contract DE-AC96-81PO10088 dated December 31, 1981

G-6. Shell Acadian River Terminal Tie-Ins at Discharge Header 1 and 2, Dock Lines 1 and 2 (pending)