U.S. DEPARTMENT OF ENERGY

Strategic Petroleum Reserve
Project Management Office
New Orleans, Louisiana

SHELL PIPELINE COMPANY LP FY 2018 ANNUAL LEASE PERFORMANCE EVALUATION OF THE BAYOU CHOCTAW PIPELINE (REDSTICK) (DE-RL96-97PO70011)

October 24 & 25, 2018

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SECTION A – INTRODUCTION

In accordance with the lease agreement between the Department of Energy (DOE) and Shell Pipeline Company LP (Shell), the Annual Inspection of Lessee’s activities at the Bayou Choctaw Pipeline was conducted on October 24 and 25, 2018. The purpose of the inspection was to assess the operation and maintenance condition of the facility to support the DOE Strategic Petroleum Reserve (SPR) program mission of readiness for drawdown, and to ensure Shell’s compliance with the terms and conditions of the lease agreement.

The SPR normally utilizes a three-year lease evaluation matrix for determining the scope of areas to be assessed. But due to the nearing of the end of the lease period, December 31, 2017, (Note: lease extended 2 years until December 31, 2019) all item areas listed for all 3 years listed on the matrix were assessed. The assessment areas are listed below.

1. Bayou Choctaw Pipeline

- Cathodic Protection
- Mitigation of Corrosion
- Pipeline Contents/Pressures
- Physical Inspection Records
- Documentation of Repairs and Construction
- Operation & Maintenance Records
- Environmental Reporting
- Managing System Integrity for Hazardous Liquid Pipeline (API 1160)
- Qualification of Liquid Pipeline Personnel (API 1161)
- Pipeline Physical Inspection

This evaluation was conducted by a joint team of DOE and Fluor Federal Petroleum Operations Company (FFPO) personnel. The Lease Agreement was the principle document used to conduct this evaluation. Interviews were conducted with Lessee’s personnel (see Appendix A), a Lease Evaluation Matrix is included as Appendix B, and Lessee’s site documents were examined along with physical observations made by team members during the evaluation.

The following is the complete documentation of the findings of the evaluation team. **Bold font indicates corrective action per finding.** Per the Lease Agreement, Shell must respond to DOE with a corrective action plan within 30 working days from the date of receiving this report.

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SECTION B – DESCRIPTION OF PROPERTY

BAYOU CHOCTAW PIPELINE

The Bayou Choctaw pipeline is DOE's 37.2-mile pipeline, 36-inch crude oil pipeline from Bayou Choctaw to St. James Terminal. Shell leases this pipeline from DOE and operates it under the name Redstick Pipeline.

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SECTION C – EXECUTIVE SUMMARY

A preliminary in-briefing was held with Shell personnel at St. James Terminal for Bayou Choctaw Pipeline/Red Stick Lease (PO 70011) at the beginning the evaluation. At the completion of the evaluation, an out-briefing was held to discuss evaluation findings and the status of pending actions. DOE noted their appreciation of time and effort Shell expended working with DOE.

In addition, DOE and Shell briefly discussed the completion of corrective actions from previous assessment along with Facility Condition Assessment findings and Shell status of restoration activities.

All past restoration activities complete.

2017 Lease Assessment Corrective Actions from previous year, addressed by Shell.

NONE

The following is a summary of the effectiveness of Shell's management control systems for all functional areas evaluated.

Those findings with effective performance are not bolded.

Findings requiring corrective action by Shell are in bold font.

Shell must respond to DOE with a corrective action plan within 30 working days from the date of receiving this report.

1. Areas of Effective Performance

- Cathodic Protection
- Mitigation of Internal Corrosion
- Pipeline Contents/Pressures
- Physical Inspection of Records
- Documentation of Repairs and Construction
- Operation & Maintenance Records
- Environmental Reporting
- Managing System Integrity for Hazardous Liquid Pipeline (API 1160)
- Qualification of Liquid Pipeline Personnel (API 1161)

2. Areas that include items Needing Corrective Action

- NONE

Listing of Items Needing Corrective Action

None.

SECTION D – SPECIFIC FINDINGS

Those findings with effective performance are not bolded.

Findings requiring corrective action by Shell are in bold font.

1. OPERATIONS

A. ANNUAL CATHODIC PROTECTION SURVEY RESULTS (DOT 195-573 a)

1. Requirements:

(a) Each operator shall conduct tests on the protected pipeline at least once each calendar year, but with intervals not exceeding 15 months. However, if tests at those intervals are impractical for separately protected short sections of bare on ineffectively coated pipelines, testing may be done at least once every 3 calendar years, but with intervals not exceeding 39 months.

(b) Identify before December 29, 2003, or not more than 2 years after cathodic protection is installed, whichever comes later, the circumstances in which a close-interval survey or comparable technology is practicable and necessary to accomplish the objectives of Paragraph 10.1.1.3 of NACE Standard RP0169-96.

2. Findings:

Positive Findings:

(1) ine potential readings were reviewed for the past two years. Inspections were performed in February 2017 and February 2018. All readings were within acceptable limits. No major shifts in protection were noticed over this time.

(2) Potentials along the pipeline remain well above the target level.

(3) Close interval survey was performed by Shell previously with a CPCM pigging tool. Inspection Services were performed by Baker Hughes in August 2010. This inspection has not yet been repeated as of 10/25/17. However, an Instant Off survey was performed in 2016 and 2017. CP readings taken at same points as annual survey, but with rectifiers cycled off. This test establishes the potential for the line.

Findings Requiring Corrective Action: None.

B. RECTIFIER AND OTHER DEVICES (DOT 195-573 c)

1. Requirement:

c) *Rectifiers and other devices*. You must electrically check for proper performance each device in the first column at the frequency stated in the second column.

Device	Check frequency
Rectifier	At least six times each calendar year, but with intervals not exceeding 2½ months.
Reverse current switch	
Diode	
Interference bond whose failure would jeopardize structural protection	
Other interference bond	At least once each calendar year, but with intervals not exceeding 15 months.

2. **Finding:**

Positive Finding:

(1) Inspections at rectifiers were reviewed over the past two years. Shell has installed Watchdog Remote Monitoring Units (RMU) on their rectifiers but since 2014 has been slowly replace those with the new Abriox Remote Monitoring Units as the older Watchdog failed. This allows them to review readings twice per month, in addition to annual inspections. Readings have been reviewed to determine if any major shifts or changes in protection have occurred over the past year and none was found. Present output readings on the pipeline are meeting the requirements.

Findings Requiring Corrective Action: None.

C. ENVIRONMENTAL REPORTING (BAYOU CHOCTAW PIPELINE)

1. **Requirement:**

40 CFR 110 – Discharge of Oil

Spill Releases – The discharge of oil in quantities harmful to the public health or welfare or to the environment is prohibited if it violates an applicable water quality standard or causes a film, sheen, sludge, or emulsion to form on the water surface.

2. **Finding:**

Positive Finding:

(1) There have been no spills releases or notifications for the Bayou Choctaw 36-inch pipeline (Redstick).

Findings Requiring Corrective Action: None.

D. HIGH CONSEQUENCE AREAS (DOT 195.452)

1. Reference:

High Consequence Areas (DOT 195.452)

2. Requirements:

(1) Has Shell identified all pipeline segments that could affect a high consequence area for Redstick 36-Inch Pipeline based on smart pigging and inspections (DOT 195.452 (b)(i))?

(2) Has Shell completed a Base Assessment Plan for the Redstick 36-Inch Pipeline (DOT 195.452 (b)(ii)?

(3) Has Shell conducted risk analysis for the line segments that could affect the HCA (DOT 195.507 (a) through (b))?

(4) Has Data Integration been completed (DOT 195.452 (f)(3))?

3. Findings:

Positive Findings:

(1) An HCA analysis is performed every year on Shell DOT regulated assets. The HCA's are identified and reported to PHMSA via the Annual Report. The last ILI was done this year on 9/13/18. The final report has not yet some back from the ILI vendor. Final report is due 11/17/18. Prelim report received 10/12/18 showed no immediate condition.

(2) A baseline inspection was completed in July 2008, which is within the DOT 180-day review requirement from the date survey report was received. The baseline inspection confirmed that 5 dents were called below the reporting

criteria of <2% reduction of diameter but with metal loss. A technical evaluation of the 5 dents with corrosion were performed by professional engineer in Louisiana and determined not to require additional analysis. Dents were less than the 2% required reduction in diameter and corrosion has been mitigated.

The January 2008 smart pig survey report also included 2 corrosion anomalies with corrosion greater than 50% wall loss. Dig inspection were performed on these locations on 4/21/08. Both locations required installations of 2-foot pressure-retaining sleeves. The next survey was performed in April 2013 to meet the DOT 5-year inspection plan. Results of the 2013 smart pig indicated 2 internal corrosion anomalies with corrosion greater than 50% wall loss. Additional analysis concluded that the two anomalies are non-injurious and exhibited no sign of geometric change. The 2008 data indicated 30%-40% and 39%-49% and the 2013 data indicated 50% and 53%. The percent change may be differences in tool settings. Both of these anomalies are not in an HCA segment. The 5 dents reported in 2008, fell below the reporting criteria in 2013.

(3) A risk analysis was completed on July 2008, August 2012 and Spetember 2015 and 2018 on the Shell 36" pipeline. The Shell risk program calculates threat, probability, and consequence.

(4) Shell has completed the data integration as part of the risk analysis from September 2015 and will be performed again in March 2019.

<u>Findings Requiring Corrective Action</u>: None.

E. HIGH CONSEQUENCE AREA - INTEGRITY MANAGEMENT PLAN (DOT 195.452)

1. Reference:

High Consequence Areas (DOT 195.452) – Integrity Management Plan

2. Requirements:

(1) Develop a written integrity management program that addresses the risk of each segment of the pipeline for Category 1 operators by March 31, 2002.

(2) Include in the program an identification of each pipeline or pipeline segment for Category 1 operators by December 31, 2001.

(3) Include in the program a plan to carry out baseline assessments of the line pipe.

(4) Include in the program a framework that address the element of integrity management program including continual integrity assessment and evaluation and initially indicates how decisions will be made to implement each element.

(5) Implementation of the program.

(6) Have the facilities been considered in the risk analysis for the pipeline?

(7) Have you developed a process for the qualified personnel reviewing assessment results?

(8) Have you developed a specification sheet for tools, both caliper pigs and smart pigs?

(9) Has Shell provided an Emergency Flow Restriction Device (EFRD) analysis on each pipeline and was it documented?

(10) Does the Shell IMP require the repair matrix as identified in the DOT regulations?

3. Findings:

Positive Findings:

Shell has confirmed that their integrity management program has assessed the baseline schedule for the DOE pipeline, and an internal inspection tool was performed on March 20, 2003; the second inspection was performed in January 2008, and the most recent was performed in April 2013.

(1) Shell has provided documentation that the integrity management program has been written and is in place. The document was reviewed and updated in 2005.

(2) As part of the program, a detailed list of all the pipelines has been identified, and the DOE Redstick pipeline is included in the matrix. The schedule to perform the inline inspection on the DOE pipeline is listed above.

(3) The plan to carry out the inspection is to perform an in-line inspection with a corrosion tool and a geometry tool. Last inspection was performed in April 2013. Inspection reports were received by DOE and have been uploaded to SharePoint.

(4) The Shell document Section 5.1, Criteria for Determining Integrity Assessment Method, states that the only two methods that approved by the DOT to perform integrity assessments are the inline inspections and pressure testing. As such, they are the only methods addressed in its Integrity Management Plan. Present requirement is every 2 years and is revised to be performed on a 3-year plan.

(5) The risk assessment was last updated in September 2015 on the pipeline.

(6) The facilities were also included in the continual risk assessment based on the Integrity Management Plan. Risk assessment includes the pipeline and all facilities attached.

(7) A process for qualifying personnel is documented in the Integrity Management Plan Appendix H. The plan describes what minimum qualifications personnel are required to maintain to perform work in accordance with the Integrity Management Plan.

(8) Specification sheets have been reviewed.

(9) The complete risk assessment has identified the high consequence areas as required by the DOT regulation. Shell evaluates the need for pipeline block valves or check valves based (EFRD) on a number of factors called release potentials which include, location/spacing (rivers, critical), pipeline elevation profile, local or remote operation, accessibility (manual valves), closure time (local & remote). Shell's risk assessment performed on this pipeline has determined that motor operators or check valves were not required based on release from a full line rupture.

(10) Repair matrix has been reviewed and is provided in Section I of the Integrity Management Plan rule.

<u>Findings Requiring Corrective Action</u>: None.

<u>FFPO Person Responsible for Corrective Action Plan</u>: N/A

F. <u>DOT OPERATOR QUALIFICATION PROGRAM (49 CFR 195.505) & DOT OPERATOR QUALIFICATION RECORDKEEPING (49 CFR 195.507)</u>

1. Reference:

DOT Operator Qualification Program (49 CFR 195.505)
DOT Operator Qualification Recordkeeping (49 CFR 195.507)

2. Requirements:

(1) Identification of covered tasks that personnel perform on our pipeline facilities.

(2) Assurance, through evaluation, that individuals are qualified to perform covered tasks.

(3) Definition of the process by which non-qualified individuals may perform a covered task under the direct observation of a qualified person.

(4) Evaluation of an individual if there is reason to believe that the individual's performance of a covered task contributed to an accident as defined by DOT regulations.

(5) Evaluation of an individual if there is reason to believe that the individual is no longer qualified to perform a covered task.

(6) Assurance that changes affecting covered tasks are appropriately communicated.

(7) Identification of the intervals at which re-evaluation of an individual's qualifications is needed. Each operator shall maintain records that demonstrate compliance with this subpart.

(a) Qualification records shall include:

1) Identification of qualified individual(s);

2) Identification of the covered tasks the individual is qualified to perform;

3) Date(s) of current qualification; and

4) Qualification method(s).

(b) Records supporting an individual's current qualification shall be maintained while the individual is performing the covered task. Records of prior qualification and records of individuals no longer performing covered tasks shall be retained for a period of 5 years.

3. Findings:

Positive Findings:

(1) The comprehensive Operator Qualification program is structured to identify task, evaluate and document required qualifications, training, and safety for all operators. All of the operators are certified and at no time are there nonqualified personnel allowed to perform or supervise tasks. In addition, all work permits (task) identify the operator and their qualifications/credential in support of the Operator Qualification program. Shell uses IS Networld as a third-party Qualification Program for Operator Qualification.

(2) A random selection of personnel qualifications were reviewed and was found to be acceptable. No employee qualifications were expired. Employees are qualified for a 3-year period.

Findings Requiring Corrective Action: None.

II. MAINTENANCE

A. MITIGATION OF INTERNAL CORROSION (DOT 195-579 b INHIBITORS)

1. Reference:

Mitigation of Internal Corrosion (DOT 195-579 b)

2. Requirements:

(b) If you use corrosion inhibitors to mitigate internal corrosion, you must –

(1) Use inhibitors in sufficient quantity to protect the entire part of the pipeline system that the inhibitors are designed to protect;

(2) Use coupons or other monitoring equipment to determine the effectiveness of the inhibitors in mitigating internal corrosion; and

(3) Examine the coupons or other monitoring equipment at least twice each calendar year, but with intervals not exceeding 7½ months.

Pipeline Pigging Frequencies (DOT 195-579 Guidance & DOT 195-452) Corrective Action (DOT 195-585)

3. Positive Findings:

1) Shell utilizes Multi-Chem Inhibitor MX6-1110, a water soluble, oil dispersible corrosion inhibitor. Chemical data sheet indicates it should be utilized at 3 to 5 ppm. Most recent report (September 2018) indicated an injection rate of 3.16 ppm. To determine if inhibitors are utilized in sufficient quantities the operator performs tests on any water samples that are removed from the pipeline. Residual water levels above 100 ppm indicate that

sufficient quantities of inhibitor are being injected. Shell recently changed their water sample and coupon analysis contract to Enhance Co. and has not performed water samples. Coupon readings detailed below indicated inhibitors were effective in mitigating the internal corrosion.

2) Coupons are utilized and evaluated every 6 months at the Placid facility. Readings are taken at Placid because it is at the end of the pipeline and any levels would provide insight to the condition of the Redstick pipeline along with the Placid line. Acceptable level of corrosion generated from coupon testing in crude oil pipelines is 1 mil per year (MPY) per Multi-Chem. Coupon analysis revealed corrosion rates of 0.10 MPY between 1/10/2018 to 7/23/18. The coupon was taken at a drop out station located in Placid facility. The station is intended to be a worst-case situation where the water would drop out and cause the highest amount of corrosion similar to a low spot in the pipeline. These readings were very good and indicated virtually no corrosion.
3) Corrosion coupons have also been installed in the 42-inch shipline to Dock 2 and the 20-inch barge line to Dock 1. These coupons are checked every 6 months and indicated no significant corrosion on these lines. Annual corrosion rate from corrosion coupon is 0.71 MPY.
4) Shell has established a target for running cleaning pigs through the Redstick pipeline once per month (schedule permitting) with a minimum frequency of once per quarter. No debris was found during any pigging operations over the last year.
5) An inline inspection (smart pig) is schedule to run on 10/25/18 on the 42-inch shipline from the terminal to Dock 1.
6) An inline inspection (smart pig) was run in September 2018 on the Redstick pipeline. No locations requiring immediate repairs were identified by the inspection. Final Report expected

in mid-November. Next smart pig inspection is planned for 2023.

7) No corrective actions due to corrosion were required, other than typical maintenance painting.

Findings Requiring Corrective Action: None.

B. CORROSION CONTROL OF ATMOSPHERIC CORROSION (DOT 195-583)

1. Reference:

Corrosion Control of Atmospheric Corrosion (DOT 195-583)

2. Requirement:

You must inspect each pipeline or portion of pipeline that is exposed to the atmosphere for evidence of atmospheric corrosion at least once every 3 years, but with intervals not exceeding 39 months. During inspections you must give particular attention to pipe at soil-to-air interfaces, under thermal insulation, under disbonded coatings, at pipe supports, in splash zones, at deck penetrations, and in spans over water. If you find atmospheric corrosion during an inspection, you must provide protection against the corrosion as required by 195.581. You must clean and coat each pipeline or portion of pipeline that is exposed to the atmosphere.

3. Finding:

Positive Finding:

Issues with valve stem covers and actuator from previous year's finding have been corrected. Maintenance painting is done every year as needed. Next Atmospheric Inspection is on schedule to be completed in 2019.

Findings Requiring Corrective Action: None.

C. OFFSITE BLOCK VALVE FUNCTION REPORT (BAYOU CHOCTAW PIPELINE)

1. Reference:

Regulation DOT 195-420

2. Requirement:

Regulation DOT 195-420 requires that each operator:

(a) Each operator shall, at intervals not exceeding 7½ months, but at least twice each calendar year, inspect each mainline valve to determine that it is functioning properly.

3. Findings:

Positive Findings:

(1) Valve inspections have been performed twice per year (April 2018 and Ocotber 2018) in accordance with the DOT regulations to verify the functionality of the valves. The reports indicate the satisfactory condition of the valve station and valve functionality. No discrepancies were noted.

(2) Stem protectors have been caulked to prevent water intrusion that had been noted in previous field inspections.

D. PRESSURE LIMITING DEVICE TEST REPORT (DOT 195-428 a, d)

1. Reference:

Pressure limiting device test report (DOT 195-428 a, d)

2. Requirement:

Section 195.426, Scraper and Sphere Facilities.

No operator may use a launcher or receiver that is not equipped with a relief device capable of safely relieving pressure in the barrel before insertion or removal of scrapers or spheres. The operator must use a suitable device to indicate that pressure has been relieved in the barrel or must provide a means to prevent insertion or removal of scrapers or spheres if pressure has not been relieved in the barrel.

(a) Except as provided in paragraph (b) of this section, each operator shall, at intervals not exceeding 15 months, but at least once each calendar year, or in the case of pipelines used to carry highly volatile liquids, at intervals not to exceed 7½ months, but at least twice each calendar year, inspect and test each pressure limiting device, relief valve, pressure regulator, or other item of pressure control equipment to determine that it is functioning properly, is in good mechanical condition, and is adequate from the standpoint of capacity and reliability of operation for the service in which it is used.

(b) After October 2, 2000, the requirements of paragraphs (a) and (b) of this section for inspection and testing of pressure control equipment apply to the inspection and testing of overfill protection systems.

3. Finding:

Positive Finding**:**

(1) Operator performs tests on the relevant pressure limiting devices at least once each calendar year. All devices, including the surge relief valve system were tested in November 2017 and will be tested again in November 2018. All tests indicated that devices were set at the correct pressures and were functioning properly.

Findings Requiring Corrective Action: None.

E. MAXIMUM OPERATING PRESSURE (DOT 195-406)

1. Reference:

Maximum Operating Pressure (DOT 195-406).

2. Requirements:

Except for surge pressures and other variations from normal operations, no operator may operate a pipeline at a pressure that exceeds any of the following:

(a) The internal design pressure of the pipe determined in accordance with Section 195.106.

(b) The design pressure of any other component of the pipeline.

(c) Eighty percent of the test pressure for any part of the pipeline which has been tested under Subpart E.

(d) Eighty percent of the factory test pressure or of the prototype test pressure for any individually installed component which is exempt from testing under 195.305.

No operator may permit the pressure in a pipeline during surges or other variations from normal operations to exceed 110 percent of the operating pressure limit established under paragraph (A) of this section. Each operator must provide adequate controls and protective equipment to control the pressure within this limit.

3. Finding:

Positive Findings:

(1) Electronic history graphs from Shell's operations control center from 10/24/17 to 10/24/18 were reviewed. Graphs indicated an average maximum operating pressure (MOP) of 250 psig. One pressure spikes over 600 was recorded on June 07, 2018 but determined to be a false pressure reading (could be a Rosemount Pressure Transducer being calibrated)

The established maximum allowable operating pressure (MAOP) of the pipeline is 335 psig.

Findings Requiring Corrective Action: None.

F. AERIAL INSPECTION REPORTS (DOT 195-412 a)

1. Reference:

Aerial inspection reports (DOT 195-412 a)

2. Requirement:

Each operator shall, at intervals not exceeding 3 weeks, but at least 26 times each calendar year, inspect the surface conditions on or adjacent to each pipeline right-of-way. Methods of inspection include walking, driving, flying, or other appropriate means of traveling the right-of-way.

3. Findings:

Positive Findings**:**

(1) Aerial inspections were performed every week (weather permitting) for the past year, with no more than 2 weeks between inspections. Approximately forty (40) flights were successfully performed. Inspection reports were reviewed which indicated any visible activity on the right-of-way, including construction equipment.

(2) All reports of visible activity were addressed by Shell to identify the activity and to indicate that operators were aware of the activity.

Findings Requiring Corrective Action: None.

G. EXTERNAL INSPECTION REPORTS OF PIPE REMOVED (DOT 195-569)

1. Reference:

External inspection reports of pipe removed (DOT 195-569)

2. Requirement:

Whenever you have knowledge that any portion of a buried pipeline is exposed, you must examine the external corrosion if the pipe is bare, or if the coating is deteriorated. If you find external corrosion requiring corrective action under 195.858, you must investigate circumferentially and longitudinally beyond the exposed portion (by visual examination, indirect method, or both) to determine whether additional corrosion requiring remedial action exists in the vicinity of the exposed pipe.

3. Finding:

Positive Finding:

(1) No pipe was removed from service or uncovered over the past two years that would have required inspection of the pipeline for internal or external corrosion.

Findings Requiring Corrective Action: None.

H. <u>REFERENCE: PIPELINE PHYSICAL INSPECTION</u>

1. Reference:

Offsite block valve function report (DOE 195-420)

2. Requirements:

(A) Pipeline Physical Inspection:

(a) Scraper/Sphere facilities for pipelines.

(b) All block valves for pipelines.

(c) All rectifier stations.

(d) All fenced areas around valve stations.

(e) Pipeline right-of-way markers.

3. Finding:

<u>Positive Finding</u>:

All fencing, gates and out riggers were in place and vegetation inside most valve stations were clear. All pipe line ROW signs were in place.

Valve inspections have been performed twice per year (April 2018 to October 2018) in accordance with the DOT regulations to verify the functionality of the valves. The reports indicate the satisfactory condition of the valve station and valve functionality. No discrepancies were noted.

Stem protectors have been caulked to prevent water intrusion that had been noted in previous field inspections.

Findings needing corrective action:
none

VALVE STATION: BC2

Serial#: 30791 verified on valve

GID#: 400112 tag was placed on valve during review and verified.

ELN: BC2 verified at station.

Physical Location Notes: Off of Hwy. 1 on Bayou Jacob Road on right a little pass Enterprise road crossover.

VALVE STATION: BC3

Serial#: 30793 verified on valve

GID# 400010 tag was placed on valve during review and verified.

ELN: BC3 verified at station however on one side to the fly over marker the #3 was missing.

Physical Location Notes: Off of Belleview on the right next to Walmart across the street from Plaquemine High football stadium.

VALVE STATION: BC4

Serial#: 30787 verified on valve

GID# 400011 tag was placed on valve during review and verified.

ELN: BC4 – verified at station.

Physical Location Notes: Exit off Hwy 1 onto 69/Augusta Road cross over track about 1/3 mile on left side of road in cane field across the street from houses.

VALVE STATION: BC5

Serial#: 0788 verified on valve

GID# 400012 tag was placed on valve during review and verified.

ELN: BC5 verified at station.

Physical Location Notes: Off Hwy 943, in open lot on Myles Road on right side in the middle of cane field area.

VALVE STATION: BC6

Serial#: 30789 verified on valve.

GID# 400013 tag was placed on valve during review and verified.

ELN: BC6 verified at station.

Physical Location Notes: OFF Hwy 943, in open lot on left side next to Palo Alto Rifle and Pistol Club.

VALVE STATION: BC7

Serial#: 30797 verified on valve.

GID# 400014 tag was present and verified during reveiw.

ELN: BC7 verified at station.

Physical Location Notes: On open property on the right side of Hwy 1 between house address 6896 Hwy 1 and 6969 Hw1.

VALVE STATION: BC8

Serial#: 30786 verified on vale.

GID# 400015 tag was placed on valve during review and verified.

ELN: BC8 verification at station.

Physical Location Notes: On open property on left side of Hwy 308.

III. ENGINEERING

A. DOE LEASE AGREEMENT

1. Requirement:

Lease agreement requires lessee to obtain written approval from the government to make permanent alterations, additions, or betterments to or installations upon Lease property.

Finding:

Positive Finding:

Shell prepared and submitted an ECP to the government to propose taking the 42-inch shipline to Dock 1 out of service. The ECP was rejected. This line is currently idled and filled with inhibited water. Previous corrosion inspections and AUT scans indicated heavy corrosion on the line. As of 8/24/18, Shell will be running a smart pig on 8/25/18.

Foam dam on Tank 5 was removed in 2016 is being re-installed as of today 8/24/18.

Findings Requiring Corrective Action: None.

B. GENERAL RISK MANAGEMENT

1. Requirement:

DOE/FFPO excavated pipeline valves to remove & plug valve body drains. There is a risk of leakage on these drains due to water settling and causing corrosion of the small bore piping.

Finding:

Positive Finding:

Shell was asked if they have considered this risk and what, if any plans do they have to manage it. Shell indicated that they have had a couple of small leak incidents on valve body drains at the terminal. As a result, all but two (2) body drains plugging have been completed. No plan at this time to plug the drains on the remaining valves.

Findings Requiring Corrective Action: None.

FFPO Person Responsible for Corrective Action Plan: N/A

APPENDIX A – PARTICIPANTS

ASSET EVALUATION TEAM MEMBERS

Roark, Christopher	DOE	Crude Oil Mgt Team Leader
Pizzeck, Marc	DOE	Mechanical Engineer
Walker, Deanna	DOE	Realty Officer
Nguyen, James	FFPO	Principal Engineer, Pipeline
Fresneda, Patrick	FFPO	Manager Maintenance Projects
Briuglio, Brian	FFPO	Sr. Mechanical Engineer
Brown, James	FFPO	Manager Stennis Warehouse
Ian Walsdorf	FFPO	Sr. Mechanical Engineer
Dubuc, Matthew	FFPO	Air Quality Specialist
Ivanyisky, Stephen	FFPO	Air Quality Specialist
Steib, Rod	FFPO	Manager Property
Johnson, Christopher	FFPO	Property Analyst
Herman, Art	FFPO	Property Analyst
Booth, Carol	FFPO	Sr. Property Analyst
Carlson, Steve	FFPO	Fire Protection
Guillory, Thomas	FFPO	Security
Landry, Scott	FFPO	Director Operations & Maintenance
Hebert, John	FFPO	Operations, Senior Planner
Boudreaux, Denny	Garrison	
Narvagz, Jason		
Heltz, Darren		

SHELL PERSONNEL

Green, Chester	SPLC	USCGRS
Soape, Brad	SPLC	USJSOG
Jackson, Brent	SPLC	Facility Engineer, USBSAI
Majewski, Martin	SPLC	Marine Technical Advisor
Gates, Tom	SPLC	Asset Manager
Landry, Greg	SPLC	Terminal Manager
Poche, TorySPLC	Operations Supervisor	

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APPENDIX B – LEASE EVALUATION MATRIX

Leased Asset Evaluation Criteria Assessment Schedule
Bayou Choctaw Pipeline Lease/Redstick Pipeline
(DE-RL96-97PO70011)
October 2018

	CRITERIA	1 YEAR	2 YEAR	3 YEAR
1	Cathodic Protection Records	X	X	X
2	Mitigation of Internal Corrosion	X	X	X
3	Pipeline Contents / Pressures	X	X	X
4	Physical Inspection Records	X	X	X
5	Documentation of Repairs and Construction	X	X	
6	Operation & Maintenance Records	X	X	
7	Environmental Reporting	X	X	X
8	Managing System Integrity for Hazardous Liquid Pipeline (API 1160)	X		X
9	Qualification of Liquid Pipeline Personnel (API 1161)	X		X
10	Pipeline Physical Inspection	X	X	X

*Assessed all areas due to nearing the end of the Lease period.

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