United States Environmental Protection Agency / Region 4

Clean Air Act Section 112(r), Risk Management Program Inspection Report

W&T Offshore Inc. – Onshore Treating Facility
Theodore, Alabama

July 29, 2021

1.0 Introduction

The U.S. Environmental Protection Agency's efforts to reduce the likelihood and severity of chemical accidents includes planning and legislative initiatives such as the National Contingency Plan, the Emergency Planning and Community Right-to-Know Act (EPCRA), and the Accidental Release Prevention requirements under Section 112(r) of the Clean Air Act (CAA), as amended in 1990. This report outlines an inspection of the Risk Management Program (RMP) as mandated by Section 112(r)(7) of the CAA.

The focus of this inspection was to assess compliance with RMP requirements at the W&T Offshore, Inc. Mobile Bay Onshore Treating Facility ("the Facility," or "the W&T Onshore Facility") located at 6000 Deakle Road in Theodore, Alabama. The inspection consisted of an examination of program documentation as well as site reviews of various aspects of facility operations. Personnel from the facility participated throughout the onsite portion of the inspection. Numerous documents were provided for review offsite by facility personnel. This report will provide background information about the facility and a listing of observations from the walkthrough.

2.0 Background

The W&T Onshore Facility receives raw field gas from the Gulf of Mexico via pipeline extracted from wells owned and operated by W&T Offshore, Inc. The gas received by the Facility is then passed through several separation stages to remove sulfur compounds and bring the inlet gas to proper sulfur specifications before being transferred offsite to one of two downstream facilities (the nearby DCP Midstream and Williams Mobile Bay gas processing plants) via pipeline. Facility personnel indicated that inlet field gas can be received at up to 2.2% by weight hydrogen sulfide (H_2S). Gas sent offsite by pipeline must be less than 5 parts per million (ppm) H_2S; however, processed gas typically meets a 2 ppm H_2S specification. After the initial separation stages, H_2S-rich acid gas is processed through one of two parallel Claus Unit/Tail Gas Unit trains (the "105 Train" and the "104 Train") which each consist of multiple reactors, heat exchangers, and contactors. H_2S-rich gas entering the Claus Unit/Tail Gas Unit processing trains is typically between 50% - 70% H_2S. Molten sulfur is recovered and stored in either the sulfur storage tank or one of two sulfur storage pits before being trucked offsite to customers. The sulfur plant has a rated processing capacity of approximately 630 million standard cubic feet per day (mmscfd) of gas, and the Facility can produce up to 220-long-tons per day of sulfur; however, Facility personnel reported that they currently process between 130 – 170 mmscfd of gas and produce approximately 105-long-tons per day of sulfur.

Inlet gas first passes through the slug catcher (approximately 2,500 barrels [bbl]), which acts to remove entrained condensed liquids and solids from the well field. The gas then passes through the “Primary Unit” area of the plant which consists of two amine contactor towers operated in parallel to remove H_2S followed by two triethylene glycol (TEG) dehydration wash towers operated in parallel to remove moisture (water). Processed gas is sent downstream via pipeline to the DCP Midstream and Williams Mobile Bay gas processing plants. Liquids from the bottoms of the amine contactor towers are sent to an amine flash vessel, amine heat exchanger, and an amine stripper tower to recover the amine liquids (methyl diethanolamine [MDEA]) and produce a H_2S-rich acid gas stream. Moisture-rich TEG from the wash towers is sent to a reboiler to boil-off water and recycle the lean TEG back into the dehydration system.

Acid gas generated from the amine contactors is processed through two more iterative “Flexsorb” separation stages in the Tail Gas Unit section, which consist of contactor towers and heat exchangers, before the gas is sent to the Claus Unit section. Both the 104 Train and 105 Train include a thermal reactor and a series of iterative condensers and reactors that separate out molten sulfur from the processed acid gas. Tail gas streams from each Claus Unit are redirected back as an inlet stream to the Tail Gas Unit Flexsorb contactor towers to recover residual H_2S. Residual gas streams from the 104 Train and 105 Train are each sent to a dedicated thermal oxidizer for combustion.

The Facility was originally constructed between 1991 and 1993 by ExxonMobil. W&T Offshore, Inc. acquired the Facility from ExxonMobil in mid-2019 and took over full day-to-day Facility operations in late-2019. Facility personnel reported that the Facility underwent “turnaround” events in 2010 and 2016, and that the acid gas flare tip was replaced in 1999/2000. Facility personnel were not aware of any other process equipment replacements or upgrades at the Facility.

The Facility has a total of 45 onsite staff, 20 of which are board operators. Five employees are employed as maintenance staff, and an additional six employees are employed as Instrumentation/Electrical (I&E) technicians. The Facility operates 24 hours per day, 7 days per week with five operators, between 2 to 3 maintenance staff, and 3 I&E technicians staffed actively on a particular shift. No labor union is present at the facility.

The Facility is subject to the RMP requirements of 40 C.F.R. Part 68 applicable to “Program 3” facilities as well as EPCRA Sections 302, 311 and 312. Additional background and Facility-specific details are summarized as follows in Table 1.

TABLE 1: Inspection Information Summary

Inspection Team

Lead Inspectors:	Mark Briggs, Eastern Research Group, Inc. (ERG) Zachary Good, ERG

Date of Facility Visit: July 29, 2021

Facility Identification

Name: W&T Offshore, Inc. – Mobile Bay Onshore Treating Facility (OTF)
Street Address: 6000 Deakle Road
City: Theodore County: Mobile State: Alabama Zip: 36582
EPA Facility ID No: 1000 0021 2584
Latitude: 30.429570
Longitude: -088.181880

Name, address and phone of corporate parent company:
Owner/Operator: W&T Offshore, Inc.
Mailing Address: 5718 Westheimer Road, Suite 700
City: Houston State: Texas Zip: 77057
Phone: (713) 626-8525
Webpage: https://www.wtoffshore.com

Name, title, and email of person responsible for 40 C.F.R. Part 68 implementation:
Name: Valerie Greeve
Title: Environmental Program Manager
Phone: (713) 626-8525
Email: vgreeve@wtoffshore.com

Name and title of emergency contact:
Name: Eric Harbison
Title: Operations Supervisor
Day phone: (251) 973-4601
24-hour Phone: (251) 973-4634
Email: eharbison@wtoffshore.com

Name and titles of stationary source personnel involved in site inspection *(accompanied site tours, provided documents and explanations):*

Name	**Title**	**Phone**	**Email**
Doris Leach	Administrative Coordinator	(251) 973-4364	dleach.consultant@wtoffshore.com
Terry Wilson	HSE Manager	(251) 973-4628	twilson@wtoffshore.com
Valerie Greeve	Environmental Program Manager	(251) 973-4627	vgreeve@wtoffshore.com
Eric Harbison	Mobile Bay District Supervisor	(251) 973-4601	eharbison@wtoffshore.com

Date and Program Levels of Submitted Risk Management Plan (RMPlan)
Date of most recent submissions: October 15, 2020

Process 1 as reported in RMPlan:
Process: Natural Gas Extraction
Process ID: 1000112322
Process Chemical ID: 1000140393 (Hydrogen Sulfide – CAS No. 7783-06-4)
Process Chemical Quantity: 20,287 pounds
Program Level as reported in RMPlan: 3
NAICS code: 21113 (Natural Gas Extraction)

3.0 Observations

The inspection of the facility evaluated compliance with various sections of the RMP regulations (40 C.F.R. Part 68, Subpart D – Program 3 Prevention Program) and the inspection checklist included in "Guidance for Conducting Risk Management Programs Inspections under Clean Air Act Section 112(r)." The inspection included discussions with the Facility personnel regarding a myriad of issues related to Facility operations, the Facility's RMP, a review of paperwork associated with the facility's most recent RMPlan, and a walkthrough of the facility. An inspection in-brief and out-brief were conducted. Observations from the RMP inspection at the facility are discussed below:

RMP Observations and Potential Areas of Concern (AOCs)

1. 40 C.F.R. § 68.15(d) requires the owner or operator of a stationary source with a process subject to Program Level 3 to do the following:
   (1) Develop and implement a management system as provided in §68.15;
   (2) Conduct a hazard assessment as provided in §§ 68.20 through 68.42;
   (3) Implement the prevention requirements of §§ 68.65 through 68.87;
   (4) Coordinate response actions with local emergency planning and response agencies as provided in §68.93;
   (5) Develop and implement an emergency response program, and conduct exercises, as provided in §§68.90 to 68.96; and
   (6) Submit as part of the RMP the data on prevention program elements for Program 3 processes as provided in §68.175.

   The Facility has implemented a Program 3 Prevention Program in an effort to comply with 40 C.F.R. Part 68 requirements based on the determination that the Facility has more than the RMP threshold quantity of H_2S (CAS No. 7783-06-4) toxic substance present onsite. The Facility has determined that it does not have regulated flammable substances onsite in quantities above the threshold quantity (i.e., 10,000 pounds). W&T Offshore, Inc. has claimed that "No flammable substances are subject to RMP at the Onshore Treating Facility as determined by the exemptions in §68.115(b)(2)(iii)." Specifically, the Facility has claimed coverage under the following exemption in 40 C.F.R. Part 68 to preclude flammables present in inlet gas streams received and processed by the Facility from being considered for RMP applicability:

> "*Naturally occurring hydrocarbon mixtures. Prior to entry into a natural gas processing plant or a petroleum refining process unit, regulated substances in naturally occurring hydrocarbon mixtures need not be considered when determining whether more than a threshold quantity is present at a stationary source. Naturally occurring hydrocarbon mixtures include any combination of the following: condensate, crude oil, field gas, and produced water, each as defined in § 68.3 of this part*."

The Facility also stated that "The natural gas present at OTF is 'field gas' prior to entering a 'natural gas processing plant'." Based on documentation received from the Facility, the W&T Onshore Facility has historically considered all of its processing equipment "… 'one process' from inlet gas receiver to sales and the treating process" for the purposes of assessing RMP applicability. The Facility receives inlet gas streams via pipeline from offshore production platforms, and those gas streams immediately enter into the slug catcher to remove entrained liquids before entering several iterative separation stages that remove both H_2S and any remaining water. Raw field gas is extracted and present at production well pads and/or offshore platforms rather than the initial gas processing steps located at stationary gas processing facilities. The Facility may have misapplied the exemption criteria under 40 C.F.R. § 68.115(b)(2)(iii), and if so, has not properly conducted its threshold determination for flammable substances. The EPA notes that, when only considering the potential inventory of the slug catcher, the Facility's maximum intended inventory for flammables would be over 100,000 pounds of a flammable mixture.

The Facility has not done the following regarding the presence of flammable substance(s) in excess of the threshold quantity (10,000 pounds):

- Conducted a hazard assessment as provided in §§ 68.20 through 68.42.
- Submitted as part of the RMP the data on prevention program elements for Program 3 processes as provided in § 68.175.

2. 40 C.F.R. § 68.65(d)(2) and (3) requires the owner or operator to document that equipment complies with recognized and generally accepted good engineering practices (RAGAGEP) and for existing equipment designed and constructed in accordance with codes, standards, or practices that are no longer in general use, requires the owner or operator to determine and document that the equipment is designed, maintained, inspected, tested, and operating in a safe manner.

    - Localized corrosion and visible evidence of historical sulfur leaks were observed on piping associated with the residue gas scrubbing towers, Amine Contactor Towers, at the inlet to one of the Train 105 Sulfur Recovery Unit (SRU) reactors, on the Train 5 Claus Reactor 1, and on piping associated with the Train 105 SRU condensers. The high sulfur content of many of the process streams at the Facility may result in increased risk of service-specific and localized corrosion, as specified under Section

6.3.5 of API RP 574 (1998). The inspection team requested the Facility provide historical inspection records (external visual or internal) for process piping and pressure vessels, but the facility stated these records were not available. Section 5.1 of API RP 574 (1998) states that:

> "*The primary purpose of inspection is to perform activities using appropriate techniques to identify active deterioration mechanisms and to specify repair, replacement, or future inspections for affected piping. This requires developing information about the physical condition of the piping, the causes of its deterioration, and its rate of deterioration. By developing a database of inspection history, the user may predict and recommend future repairs and replacements. The user can then act to prevent or retard future deterioration and, most importantly, prevent loss of containment.*"

Without the historical inspection records, the Facility cannot verify the extent (or lack thereof) of corrosion in these locations and cannot appropriately plan for future inspections, repairs, and replacements of process piping.

- Piping throughout the W&T Onshore Facility is not consistently labeled in accordance with the requirements defined in ASME A13.1 related to pipe contents and direction of flow.

- Overhead process piping nearby the rich MDEA flash tank and one set of the Facility's Emergency Shutdown (ESD) buttons was observed to be bent and exhibiting excessive vibration. Inspectors observed that this section of piping was not adequately designed or supported to minimize vibration in accordance with Section 301.5.4 of ASME B31.3 (2006) which states, "Piping shall be designed, arranged, and supported so as to eliminate excessive and harmful effects of vibration which may arise from such sources as impact, pressure pulsation, turbulent flow vortices, resonance in compressors, and wind." Section 7.5 of API 570 (2009) also requires that piping be supported and guided such that it does not vibrate excessively.

- Inspectors observed vegetation growth in an "out of service" piece of equipment designated as the "Degassing Package" nearby the 105 Train SRU Reactor Area. Combustible materials such as grass and weeds should not be present in areas where such materials would present an unsafe risk for combustion, as required by Section 5704.2.6 of the International Fire Code (2015).

3. 40 C.F.R. § 68.73(d) establishes mechanical integrity (MI) inspection, testing, and recordkeeping requirements for process equipment in accordance with manufacturers recommendations, applicable RAGAGEP, and Facility procedures. While onsite, inspectors requested historical MI inspection and testing data associated with several process units: the Acid Gas Cooler, Acid Gas Surge Drum, and associated piping; the TEG Dehydration Columns; and piping associated with the Amine Stripper Towers. Facility personnel indicated that they had limited, if any, access to historical MI program documentation for Facility process equipment due to document transfer issues associated with the late-2019

acquisition from ExxonMobil. Documentation provided in response to EPA's post-inspection Request for Information (RFI) indicates that various API 510 external visual and internal inspections have been scheduled for the 4th Quarter of 2021. However, the Facility does not have records of any historical inspections or tests conducted on Facility process equipment. Based on the presumed original installation dates of much of the process equipment at the Facility (i.e., early-1990s), the Facility would have been required to conduct several rounds of external visual and internal inspections for pressure vessels (API 510) and process piping (API 570).

Inspection Report,

Prepared by:

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