SPCC INSPECTION RESULTS IN IMPROVED CORROSION PROTECTION AT MAJOR REFINERY

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ABSTRACT

EPA Region 3 conducted an SPCC/FRP inspection in late 1997 by at a major east coast refinery, situated along Curtis Bay in Baltimore MD. Curtis Bay drains into the Chesapeake Bay and a release from the site could severely impact a sensitive ecological area. During the inspection, the inspectors observed evidence of deterioration in the concrete foundations of several of the tanks. A Notice of Non-Compliance was sent to the company outlining deficiencies noted during the inspection and from the SPCC plan review. The company addressed the SPCC plan deficiencies but failed to address issues regarding the tank foundations, periodic integrity testing and protection of buried piping. An Administrative Complaint was issued under Section 311 of the CWA. The company denied the allegations and asked for an administrative hearing. An Alternate Dispute Resolution (ADR) process was arranged. One result of the ADR was that the Facility agreed to further assess the cathodic protection system and soil corrosivity, and to evaluate the foundations of five of the ASTs. Simultaneously, EPA arranged for an expert to provide technical consulting support in the area of American Petroleum Institute (API) 653 inspections and compliance procedures. When the company submitted the results of their API inspection, they indicated that the ASTs were safe and calculated the remaining service life to exceed the 20 year inspection interval requirement. They proposed the next inspection interval to be the maximum of 20 years. EPA's consultant was able to demonstrate that the company had made incorrect assumptions about the as-built tank foundation design. This resulted in incorrect calculations regarding the degree of existing cathodic protection. As a result, EPA prevailed in recalculating a service life/internal inspection interval of 4.58 years and requiring some additional corrective measures to be taken at the facility. The result of EPA's action is that the ASTs located at the site will be operated with a higher degree of safety and environmental protection.

INTRODUCTION

EPA Region 3's Hazardous Site Cleanup Division, Removal Branch, Removal Enforcement and Oil Section is responsible for the management, oversight and implementation of the Region's Oil Enforcement Program. The Section implements an aggressive program that includes conducting inspections pursuant to Facility Response Plan (FRP) regulations (40 CFR 112.20 and 112.21, including Appendices B through F) and Spill Prevention Control and Countermeasure (SPCC) regulations (Title 40, Code of Federal Regulations, Part 112 (40 CFR 112)) at targeted facilities throughout the region.

With limited resources, the Region's practice is to generally target facilities for inspection in a particular area or zip code, as determined on a yearly basis. Targeting facilities within a previously defined zip code provides a neutral scheme and should avoid any abuse of Agency discretion or the appearance of arbitrary behavior. In addition to geographic targeting, the following criteria may be considered prior to inspecting facilities for compliance with the SPCC/FRP rule: Spill History; Emergency Response; Referrals from other agencies or the public; Initiatives based on geographical, environmental or multi-media concerns; and Significant and Substantial Harm from facilities subject to FRP requirements requiring EPA approval. In addition to the criteria noted above, facilities may be identified as possible inspection candidates based on field observations during other operations conducted by Agency personnel. In recent years, over 150 inspections have been completed annually.

Region 3's enforcement procedures establish a consistent approach for determining the appropriate response for failure to comply with prevention requirements established by applicable regulations. Industry outreach and other forms of compliance assistance have traditionally been used prior to identifying regulatory violations, and compliance assurance efforts will continue to be employed to correct minor facility inadequacies. However, it is recognized that a strong enforcement program is necessary to assure timely compliance and to eliminate any economic advantage received by the violator for failure to comply. More detailed information regarding the Region's oil program and its activities can be found on our web site at *www.epa.gov/reg3hwmd/oil/*.

The purpose of this paper is to discuss the issues involved in a particularly complex inspection and administrative followup process, to demonstrate how a potentially catastrophic release was prevented. In order to protect the confidentiality of the owners of the facility where this incident occurred, it will be referred to simply as the "Facility" throughout the paper.

Background

The main requirement of facilities subject to SPCC and FRP regulations is the preparation and implementation of a Plan to prevent any discharge of oil into waters of the United States or to immediately respond to any discharges that may have occurred. However, the main thrust of the regulations is the prevention of a discharge as opposed to the "after-the-fact" or reactive cleanup measures commonly described in spill contingency plans.

The subject of this paper (the Facility) is a major oil refinery with cumulative aboveground storage tank capacity of over 31 million gallons of oil, located within 1/4 mile of a tributary to the Chesapeake Bay. Storage tank dikes and surface drainage from undiked areas are drained through valved perimeter drains to three oil/water

separators. Effluent from the separators flows into a "navigable water of the United States," as defined by Section 502(7) of the CWA, 33 U.S.C. § 1362(7), and 40 C.F.R. §§ 110.1 and 112.2.

On September 22, 1997, representatives from EPA performed a Spill Prevention, Control, and Countermeasures ("SPCC") and Facility Response Plan ("FRP") inspection of the Facility. During the field inspection, several tank foundations appeared to be deficient. Gaps were present between the tanks and their foundations and/or the foundations were found to be eroded and cracked. Based upon the inspection, EPA determined that the Facility failed to perform periodic integrity testing upon the tanks, failed to maintain appropriate comparison records, and failed to inspect and repair tank foundations, as required by Sections 40 C.F.R. § 112.7(e)(2)(vi) and (viii).

Following the inspection, EPA sent the Facility a Notice of Non-Compliance ("NON") pursuant to Section 311 (j) of the CWA, 33 U.S.C. § 1321. On February 12, 1998, the Facility sent to EPA a response to EPA's NON. Although the Facility adequately revised the Facility's SPCC Plan, they failed to fix the tank foundations and piping systems cited as SPCC violations in EPA's NON. On July 1, 1998, EPA issued and filed an Administrative Complaint and Opportunity to Request Hearing and Conference, which initiated proceedings to assess Class II civil penalties under Section 311 of the CWA. On July 27, 1998, the Facility filed an Answer and Request for Hearing and Conference, denying and asserting various defenses to the bases for the violations set forth in the Administrative Order.

On January 26, 1999, representatives of EPA and its contractors conducted a second inspection at the Facility to further assess the Facility's cathodic protection system, collect samples to test for soil corrosivity and evaluate the foundations at the tanks in question During the inspection EPA learned that the exterior bottom plate extension for one tank was substantially corroded at three separate points along the perimeter at the foundation. This corrosion caused the exterior bottom plate to deteriorate so that the plate extended less than one inch from the shell of the tank at these three points. The deterioration of the exterior bottom plate extension impaired the integrity of the tank at a critical stress point between the tank floor and the tank shell wall. Upon discovering the corroded exterior bottom plate extension, representatives of EPA and its contractors informed facility personnel of this condition and the substantial threat of a release resulting from this condition. In addition, EPA and its contractors informed the Facility's personnel that the tank should be immediately emptied and taken-out of service so as to avoid and abate any further endangerment to public health and the environment and to allow for the tank's integrity to be more fully evaluated.

On 2/9/99 EPA issued a Unilateral Administrative Order (UAO) proposing civil penalties of $137,000 and with requirements to, among other things, take the tank out of service and prepare and implement a tank inspection and repair plan, consistent with American Petroleum Institute (API) 653 standards at a minimum, to restore the tank to a condition suitable for safe operation.

In response to the UAO, the Facility authorized and conducted an API 653 tank inspection on 4/28/99. The findings of this report included a calculation regarding remaining service life of the tank bottom based on API 653 Section 2.4.7, and concluded that the remaining service life exceeded 20 years. The inspection also identified two issues: 1)corrosion of the chime (bottom plate projection outside of the shell) at several locations where the thickness or width of the chime is less than the values recommended by API (minimum thickness of 0.1" and minimum width of 3/8" from the outside toe of the shell-to-bottom weld), and 2) some disintegration (spalling) the concrete ringwall. The Facility's finite element stress analysis of the shell-to-bottom junction showed that the corrosion had no effect on the structural integrity of the tank. However, the Facility proposed a chime weld build-up to satisfy the numeric values given in API 653. In addition, to further protect the chime from potential future corrosion and prolong the tank life, the Facility proposed to abrasive blast the outer periphery of the tank bottom and then caulk it to seal and prevent any ingress of moisture between the tank bottom and the concrete ringwall.

EPA obtained a consultant with expertise in corrosion and API inspection procedures, who provided an independent opinion of the API inspection in a report dated 6/15/99. His report disagreed with the remaining service life calculation of 20 years, which is based on the formula

$$Or1 = \frac{To\text{-}MRT1\text{-}GCa\text{-}StPa\text{-}UPm.}{StPr+UPr+GCr}$$

He argued that Upr (defined as the maximum underside pitting rate, in inches per year, if the tank bottom is cathodically protected) should not have a value of zero, as the Facility report assumed. While the tank bottom was protected with an impressed current system, this system is not very effective in protecting the tank bottom which is in contact with the concrete ringwall. This is especially true near the exterior (area at the shell) of the floor plates. This area is also subject to atmospheric corrosion which an impressed current system is not effective in preventing. Based on a revised Upr of 0.0019 inches/year, derived from the measurement of corrosion found during the API inspection, he calculated Or1= 4.58 years.

In a 6/28/99 response from the Facility, they challenging the findings of EPA's contractor regarding the service life calculation, but agreed to undertake the chime build-up and sealing of the joint between tank floor and concrete ringwall. Their challenge was based on a strict interpretation of API 653, which states that Upr shall be equal to zero if the tank is cathodically protected, and does not recommend the value of Upr be determined differently for a section of tank bottom that is cathodically protected and is located adjacent to a concrete ringwall. They also cited API 653, paragraph 2.4.7.4, which acknowledges that isolated pitting will not appreciably affect the strength of the plate. They also argued that while a traditional bottom inspection typically takes into account limited information from spot thickness readings and a visual evaluation, a magnetic flux leakage inspection, which was employed during the API 653 inspection, evaluates almost 100% of the tank bottom.

EPA responded to the Facility challenge by letter dated 7/27/99, noting that the API 653 inspection report indicates critical areas of the tank bottom have experienced localized corrosion, and the critical areas are at locations which are in contact with the concrete ringwall and not effectively protected by the impressed current system. Although utilizing a Upr value of zero may be in strict accordance with API 653, good engineering practices should be applied given the circumstances in this case, in particular the evidence of corrosion in areas without sufficient cathodic protection. Actual field measurements have shown that in the critical zone of the tank floor the value for Upr is not zero because underside corrosion has in fact taken place.

On 8/16/99 EPA received a letter from the Facility, which, after additional evaluation of EPA's argument, agreed to comply with the revised calculation of 4.58 years for the reinspection interval. They stated, however, that they were doing this primarily to facilitate the completion of the UAO, and that they continued to believe their calculation was correct.

On 10/7/99, EPA received a Final Report from the Facility pursuant to the UAO, documenting the completion of the required inspection and repairs and committing to a tank inspection interval of 4.58 years instead of the 20 that they had originally proposed. In response, EPA requested by letter dated 1/12/2000 additional clarification and more details on certain aspects of the repair and inspection process. The Facility provided the requested information on 2/10/2000.

On January 5,2000, EPA issued a Consent Agreement and Final Order (CAFO) with a final civil penalty of $28,000, and several additional Supplemental Environmental Projects (SEP) not otherwise required by law that the Facility agreed to perform. The SEPs included replacing underground lines running to various storage tanks with aboveground piping, installing a leak detection system beneath several other storage tanks, and performing "Tracer Tight" testing at an agreed upon schedule.

CONCLUSION

Region 3's goal is to increase compliance rates through an integrated program of active enforcement, compliance monitoring/ assurance and formal assistance. Implementation of enforcement action will compel a rapid return to compliance, penalize the violator and recover economic savings that may have accrued through non-compliance, and deter other members of the regulated community from violating the law.

As can be seen from the foregoing information, the culmination of the inspections that were undertaken, combined with the subsequent administrative and judicial processes that were followed, clearly resulted in a safer facility, with greater reliability and improved maintenance features. The benefit of EPA's action is that the ASTs located at the site will be operated with a higher degree of safety and environmental compliance, and with significantly lower potential for a major release of petroleum products to the environment.