Date: October 22, 2018

To: Mark Hysell
Director, OSHA Eau Claire Area Office

Ruth "Mitzy" Wright
Assistant Area Director, OSHA Eau Claire Area Office

From: OSHA Health Response Team

Reason: Inspection of an Explosion with Multiple Fires that Resulted in Injuries at Superior Refinery in Superior, WI

On April 27, 2018 the HRT was asked to assist the Eau Claire Area Office with an inspection at a refinery in Superior, Wisconsin where an explosion and multiple fires injured several employees and contractors on April 26, 2018.

This incident inspection also included a PSM inspection in accordance with CPL 03-00-021, dated January 17, 2017.

Following is a report of the incident inspection as well as of the PSM inspection with observations, findings and recommendations from the HRT.

If there are any comments or questions, please feel free to contact (b)7(C) by email or by phone at (b)7(C) respectively.

Attachment: HRT-2018-SLS-07
DATE: October 22, 2018

REPORT NUMBER: HRT-2018-SLS-07

PREPARED BY: [b](C)
OSHA Health Response Team
OSHA Salt Lake Technical Center
Sandy, UT 84070

INSPECTION NUMBER: 1312169

FACILITY: Superior Refining Company – Superior Refinery
4210 Hill Avenue
Superior, Wisconsin  54880

NAICS: 324110 – Petroleum Refineries
EXECUTIVE SUMMARY

Superior Refining Company was shutting down in preparation for a plant turnaround on Thursday, April 26, 2018, when two absorber vessels in the gas concentration unit of the refinery exploded. The explosion resulted in injuries to 36 Superior Refining Company employees and contractors at the refinery.

Following the explosion Superior Refining Company’s Emergency Response Team (ERT) was able to extinguish an ensuing fire in the area. However, the explosion also sent debris, including metal pieces of the vessels into the surrounding area. One projectile hit an asphalt storage tank, penetrating the metal tank and releasing hot asphalt, which continued flowing from the tank after the first fire was extinguished.

When the asphalt level in the tank lowered to where air could enter the tank, an asphalt fire began, starting from the hole and following the asphalt spill locations. This fire continued for hours after the initial explosion and fire, and led to multiple explosions from drums and small tanks located in the areas around the spilled asphalt. Emergency response teams from the site and from the surrounding communities were ultimately able to extinguish the fire. No ERT members were injured during the response.

The HRT proposes 12 findings and 5 recommendations based on this inspection, in accordance with the following OSHA and industry standards and recommended practices.

- American Petroleum Institute (API) 510, Pressure Vessel Inspection Code: In-service Inspection, Rating, Repair and Alteration, 2014
- API 520, Sizing, Selection, and Installation of Pressure-relieving Devices, 2014
- API 521, Pressure-relieving and Depressuring Systems, 2014
- API 537, Flare Details for Petroleum, Petrochemical, And Natural Gas Industries, 2017
- API 570, Piping Inspection Code: In-service Inspection, Rating, Repair, and Alteration of Piping Systems, 2016
- American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code (BPVC), 2017
- ASME BPVC, 1968
- API 579-1/ASME FFS-1, Fitness-For-Service, 2016
# TABLE OF CONTENTS

<table>
<thead>
<tr>
<th>Section</th>
<th>Page</th>
</tr>
</thead>
<tbody>
<tr>
<td>EXECUTIVE SUMMARY</td>
<td>3</td>
</tr>
<tr>
<td>TABLE OF CONTENTS</td>
<td>4</td>
</tr>
<tr>
<td>BACKGROUND</td>
<td>5</td>
</tr>
<tr>
<td>INCIDENT DESCRIPTION</td>
<td>8</td>
</tr>
<tr>
<td>POST INCIDENT EVENTS AND RESPONSES</td>
<td>9</td>
</tr>
<tr>
<td>INCIDENT INSPECTION INFORMATION</td>
<td>14</td>
</tr>
<tr>
<td>INCIDENT OBSERVATIONS AND DISCUSSION</td>
<td>15</td>
</tr>
<tr>
<td>PSM INSPECTION INFORMATION</td>
<td>23</td>
</tr>
<tr>
<td>PSM OBSERVATIONS AND DISCUSSION</td>
<td>23</td>
</tr>
<tr>
<td>CITATIONS AND RECOMMENDATIONS</td>
<td>32</td>
</tr>
<tr>
<td>ATTACHMENT 1, PSM NEP PRIMARY AND SECONDARY QUESTIONS</td>
<td>37</td>
</tr>
<tr>
<td>ATTACHMENT 2, ASTM A-212 PRESSURE VESSEL STEEL – A CASE AGAINST CONTINUED USE</td>
<td>45</td>
</tr>
</tbody>
</table>
BACKGROUND

Superior Refinery (Figure 1) began operations in 1950 as Lake Superior Refining Company. Ownership of the refinery changed in 1958 to Murphy Oil until 2011 when it was purchased by Calumet Specialty Products. Additional units and modifications to existing facilities occurred through the years as demand for products increased and changed.

In 1961, a Fluid Catalytic Cracking Unit (FCCU) was added, which also included a Gas Concentration Unit (GCU) and an Alkylation Unit (Alky). A FCCU cracks long chain hydrocarbons into shorter chain hydrocarbons (i.e., cracks liquids into both gases and liquids). A GCU separates liquids and concentrates gases produced in the FCCU for further processing. An Alky Unit takes liquids and concentrated gases from the GCU and other units and converts them to alkylates, which include high octanes used for gasoline production.¹

In 2015, a Green Gas Unit (GGU) was added at the refinery. The GGU removes sulfur and benzene from gasoline products to meet EPA regulations for commercial fuel products.

In November 2017 Husky Energy completed acquisition of Superior Refinery from Calumet Specialty Products. The refinery primarily produces gasoline, diesel, fuel oils, asphalt and sulfur.

¹ Alkylates are hydrocarbons with alkyl groups (-(CH₂)n-CH₃) attached. Attaching these alkyl groups to hydrocarbon chains increases the number of carbons on the molecules, thus making it possible to produce higher molecular weight hydrocarbons from lower carbon number feedstock. At Superior, the alkylation unit reacted isobutane with mixed olefins from the FCCU to produce alkylate gasoline blending stock.
from its processes. The refinery has the capacity to process approximately 50,000 barrels per day of crude oil, which is received from two main oil reserves, North Dakota Bakken crude and Canadian oil sands syncrude.

In late April 2018, Superior Refining Company began shutting down the Superior Refinery for a planned major turnaround. Major turnarounds at this refinery occur every five years. Units of the refinery were being shut down in sequence, while tools and equipment were being staged in preparation for the turnaround. On Monday, April 23, the Alkyl Unit first began shutting down in accordance with the refinery’s shutdown procedures.

For this turnaround a chemical clean was planned for the GCU, so a revised operating procedure for shutdown had been developed and temporary piping for the chemical clean had been laid down throughout the unit.

Fluid Catalytic Cracking Unit and Gas Concentration Unit Shutdown
Beginning at approximately 0530 on Thursday morning, April 26, the Alky Unit was down, and the FCCU and GCU, began their shutdowns in accordance with the new procedure. Among other steps being performed that morning, the FCCU reactor was shut down and residual hydrocarbons in the FCCU and GCU began to be cleared (referred to by workers as “de-inventorying the systems”). [Note: Activities in other areas of the refinery were also happening as well but were not considered to be directly associated with this incident.]

With the FCCU reactor shut down, sometime between 0600 and 0610 operators closed the spent slide valve that separated catalyst from the reactor and the regenerator. The Main Blower was left running to lower temperatures in the regenerator (Figure 2).

(b) (4)

2 See “SUPERIOR003361-SUPERIOR003381,” FCCU, Gas Con, Merox, and C3C4 Splitter Shut-Down Procedure, dated 4/25/2018. The date this procedure was issued was the day before this shutdown began.
Sometime after shutting the spent slide valve, catalyst above the spent slide valve was either dumped by operators or fell through holes in the spent slide valve into the regenerator.\textsuperscript{3}
INCIDENT DESCRIPTION

This incident description is primarily based on employee interviews. Those interviewed indicated that at two separate times before the incident, at times between 0830 and 0930, two booms were heard from the FCCU Control Room. The source of the first boom could not be determined until later but dust was observed coming off a pipe rack near the control room after the boom occurred. The source of the second boom was from a line to the flare located in the pipe rack. The flare was also observed to light off at approximately 0930 (the approximate time of the second boom). 6 There was a limited search for the cause after the second boom, but the exact cause of the boom and of the flare lighting off was not determined and shutdown continued, which is surprising to the inspection team.

At approximately 1000 on April 26, 2018 most of the workers at the refinery were on break in various break areas, but a few contractors and a few Superior Refining Company employees were still in the general GCU area, when both the Primary and Sponge Absorbers exploded almost simultaneously. 6 The explosion knocked several workers in the area to the ground. One worker noted that while he was on the ground he looked up and saw a flash blow over him. 7

6 See (b)(7)(C) dated 5/1/2018, and (b)(7)(C) dated 5/2/2018.
6 Most workers described the explosion as one big boom but a few described it as two booms almost occurring at the same time.
7 See (b)(7)(C) dated 5/2/2018.
Video surveillance cameras in the area captured the flash from the explosion, which is seen with debris still in the air (Figure 5).

The explosion occurred within less than 100' from the control room and did not affect the integrity of the structure. The control room was an explosion-proof structure recently installed as the result of a facility siting study.

Six Superior Refining Company employees were injured: one with compound fractures of the back; another with lacerations above the knees; a third with ruptured eardrums and a possible concussion; and the other three with minor cuts and bruises. Thirteen contract employees were also injured: one with a hemorrhage in the lung; another with head lacerations; a third with a ruptured eardrum and sprained ankle; and the other ten with minor cuts and bruises. No burn injuries were reported.⁸

POST INCIDENT EVENTS AND RESPONSE

Events following the initial explosion and fire are also based primarily on employee interviews. Several Superior Refining Company employees were in the FCCU Control Room at the time of the explosion and looked out to see what had happened. A fire was localized around the absorber area and debris was still falling from the air. A hole was observed in an asphalt tank located opposite the control room and hot asphalt was flowing out this hole (Figures 6 and 7). This asphalt tank (T101) was approximately 200 feet from the explosion but was hit with a piece of debris with enough force to penetrate the tank.

The hole in the asphalt tank was big enough to allow large amounts of hot asphalt to flow out, hitting and breaking through an earthen berm, and quickly spreading along roads and low-lying areas along the ground. Wet weather resulted in steam generation as the hot asphalt hit and

---

⁸ See "Injuries — Superior Refinery Shutdown and Fire."

Page 9 of 52
travelled along the ground. The total amount of asphalt released was estimated at over 15,000 barrels (greater than 630,000 gallons).\textsuperscript{9}
Employees in the control room exited as quickly as they could to avoid running through hot asphalt, which was quickly covering the area. Evacuation alarms sounded initially in just the FCCU and GCU but ultimately a total plant evacuation resulted.

Superior Refining Company’s Emergency Response Team (ERT) responded quickly while other employees and contractors mustered at their locations.

The ERT was able to extinguish the initial fire around the absorbers within approximately 45 minutes, but during this time hot asphalt from the punctured tank continued to flow from the tank and was spreading through the tank farm and into the FCCU and GCU areas. Approximately one hour after the initial fire was extinguished, the asphalt level in the tank dropped low enough to allow air to enter the tank through the punctured location.

When air entered the asphalt tank, a fire started almost immediately. Witnesses observed the fire follow the asphalt from the hole and to the ground. Within minutes, fires had erupted almost everywhere there was asphalt and a black plume covered the air over the fires (Figure 8).

Both the Superior Refining Company ERT and nearby community fire departments responded to the asphalt fire, which continued for hours before it could be extinguished. Response to this fire was hindered due to:

- Blasts that occurred during the fire as drums, mini-bins, and other small containers that were enveloped in the flames exploded,
- Asphalt as deep as one to two feet in some areas prevented access to many of the fire locations.

Fortunately, no large tanks in the tank farm failed, and no fire or projectile damage occurred to the Alky Unit hydrogen fluoride (HF) system from this series of incidents. Projectiles and fires did however seriously damage many areas of the refinery including the electrical system as well as much of the equipment in the damaged units. The refinery will remain shut down for months as the damaged units and equipment are redesigned, fabricated and rebuilt.

Figure 8: Asphalt fire at Superior Refining Company Superior Refinery on April 26, 2019 (ABC News).
Figures 9 through 18 show some of the damage done by the explosion and fires shortly after the incident.

Figure 9: What was left of the Primary and Sponge Absorbers.

Figure 10: Stripper tower next to the absorbers.

Figure 11: Large dent in the stripper tower.
INCIDENT INSPECTION INFORMATION

An Assistant Area Director (AAD) and Compliance Safety and Health Officers (CSHOs) from the Wisconsin Eau Claire Area Office, upon learning of the incident, responded immediately to the refinery. On April 27, 2018, the HRT was contacted to assist with the incident inspection and to also assist with a PSM inspection in accordance with OSHA directive CPL 03-00-021, PSM Covered Chemical Facilities National Emphasis Program, dated January 17, 2017.

Both (b)7(C) from the HRT arrived on site on Monday, April 30, to work with Ruth (Mitzy) Wright and (b)7(C) AAD and CSHO from the Eau Claire Area Office. During this week-long visit, documents were requested and interviews were conducted. However, an inspection of the fire-damaged areas could not be conducted at that time due to explosion and fire damage and associated safety issues with entry. A later trip was planned once the site could be cleared for entries.
While on site, other inspectors and visitors also arrived, including Husky Energy corporate personnel and executives, the U.S. Chemical Safety and Hazard Investigation Board (CSB), the City of Superior Mayor, and the Wisconsin Governor.

During this week, a draft site preservation document and an asbestos cleanup and remediation plan were also prepared and submitted to involved parties for approval.

Following this visit, the AAD and CSHOs from the area office remained on site to monitor tear-down and cleanup activities. Document reviews continued following this visit as well.

The week of June 4 through 8, 2018, the same members of the HRT and Eau Claire Area Office revisited the site to perform refinery walk-arounds and to conduct additional interviews. Since this visit, document reviews have continued as Superior Refining Company continues to provide requested documents. Over 100 documents have been requested to date, the majority related to completion of the PSM inspection.

INCIDENT OBSERVATIONS AND DISCUSSION

The following observations and discussions are the cumulative result of onsite walk-arounds, interviews, discussions, and document reviews related to this incident.

Cause of This Incident
This is not a discussion of the root cause and/or causal factors but a discussion of how the incident occurred on April 26, 2018.

Between 0600 and 0610 on April 26 operators closed the spent slide valve separating the FCCU reactor from the regenerator as part of the newly revised shutdown procedure. It had been 5 years since this spent slide valve had been repaired (during the last turnaround in April 2013). This valve had been known to leak, especially towards the end of 5-year turnarounds. According to interviews and records, holes were found in the spent slide valve on two past turnarounds (April 2008 and April 2013), and those interviewed indicated that they were aware that this valve could leak because of catalyst erosion on the leading edge of the valve gate and seat ring. The spent slide valve gate seat ring was repaired during the 2013 turnaround by stick-welded overlays as seen in Figure 19. Similar damage was seen during the 2008 turnaround and a rebuilt valve was used on that turnaround. The welded overlay used a stainless steel weld rod (E309-16) with a 1/8" thick stainless finish.

Repairs and inspections of the spent slide valve in both 2008 and 2013 were performed by Houston Services located in Bixby, Oklahoma. However, no documented inspections of Houston Services’ repairs were made by Superior Refining Company inspectors. As well, no documented preventive maintenance work (PMs) was performed from 2008 to present.

Interviews of Superior Refining Company employees and managers confirmed that inspections

12 See particularly Brian McCusker interview dated 6/7/2018.
and PMs had not been done. Further, there was no indication that the spent slide valve was evaluated on either occasion for continued fitness-for-service as a result of the damage and the repairs.

During normal operations a level of catalyst is kept above the spent slide valve gate but on this turnaround there was no catalyst left above the slide gate after it was closed.\textsuperscript{14} In fact, as noted earlier in this report, the shutdown operating procedure states that catalyst should be cleared from above the spent slide gate after the gate is closed.\textsuperscript{15}

![Figure 19: Spent slide valve gate seat ring indicating that repair was made to the seat ring by stick welding – overlaying rows of weld beads.](image)

With the Main Blower operating, the spent side valve leaking, and no catalyst above the spent slide valve, air was able to travel through the spent slide valve into the reactor and then into the Main Column. Air from the Main Column then travelled to the Main Column Overhead Receiver (Figure 3) and then through the operating gas compressor. [Note: The Main Column Overhead Receiver has two pressure relief valves (15F-SV047A and B, both set at 20 psig). The inspection team believes these reliefs lifted twice between 0830 and 0930 when the booms were initially heard in the vent line to flare.]

From the compressor, high pressure air that had entered the gas system travelled through the High Pressure Receiver and into the Primary Absorber and Sponge Absorber. [Note: There is one pressure relief valve located on the High Pressure Receiver, 15G-SV006, set at 250 psig, with no pressure relief devices on the absorbers.]

Once the air-to-gas ratio dropped into the flammable range due to continued air flow into the absorbers, diluting the gas concentration, all that was needed was an ignition source to ignite the mixture. Iron sulfide, known to be present in many refinery units and known to be present in

\textsuperscript{14} See "DJI 0118," "DJI 0467," "DJI 0469," and "DJI 0473." Borescope videos of the slide valve gate inside the column.

\textsuperscript{15} See "SUPERIOR004732-SUPERIOR004776 Filled Out SOPs – Log Sheet 04262018," FCCU, Gas Con, Merox, and C3C4 Splitter Shut-Down Procedure, page 3 of 23, step 6. [Pg 27 of 45 of the document.]
this system,\textsuperscript{18} is extremely reactive with air (pyrophoric) and once exposed to air in these vessels (that are normally kept free of air) was the most likely ignition source. But regardless of the ignition source, the air/gas mixture did ignite in these two absorbers and the absorbers exploded.

**Spent Slide Valve Condition**
The spent slide valve was removed and inspected on site in early July and then sent to a testing laboratory (Zimmermann & Jensen Engineering) near Houston, TX, on July 17, 2018 for further analysis. Figures 20-22 are pictures of the valve while still at the Superior site, which showed significant erosion to the gate seat at both sides of the leading edges (i.e., edges first exposed when the gate is slid open). Since this valve is only partially opened most of the time (only enough to allow catalyst flow through the valve while still maintaining a catalyst level above the valve), the erosion in these areas is not surprising.

![Figure 20: Spent slide valve with holes on opposite sides of the valve gate seat ring.](image)

![Figure 21: Close up view of damage to one side of the seat ring.](image)

![Figure 22: Close up view of damage to the other side of the seat ring.](image)

\textsuperscript{18} (b) (4) in the feed stream to the GCU. See for example "SUPERIOR005123-SUPERIOR005124 GCU Process Description." Iron reaction with (b) (4)
Analysis by Zimmermann & Jensen Engineering provided the following results.

- Positive material identification (PMI) indicated that weld repairs performed in 2013 were performed with materials specified for the spent slide valve.  
- Clearances measured with a feeler gauge indicated that the leading edges of the valve gate (referred to in the Z&J report as the “disc”) were washed out and that the gap was too large to measure with the feeler gauge.  
- Photos of the cleaned spent slide valve gate and seat ring (Figures 23 and 24) confirmed what was seen at the site. Damage was significant to both the gate and seat ring, easily allowing catalyst to seep through the gaps from the reactor into the regenerator. Also easily allowing air to flow from the regenerator into the reactor once the catalyst above the spent slide valve was gone.

![Figure 23: Light shining through the gap between the spent slide valve gate and seat ring.](image1)

![Figure 24: Damage to the spent slide valve seat ring once disassembled.](image2)

Failure to retain sufficient catalyst level during standby operations due to worn slide valves was also found in an FCCU explosion in California in 2015 that was investigated by Cal OSHA and the CSB.  

Absorber Materials of Construction  
The absorber shells were made of American Society for Testing and Materials (ASTM) A-201 (Sponge Absorber) and A-212 (Primary Absorber) carbon-silicon steels and were installed in 1961. The ASTM standard for A-212 metal production was withdrawn in 1967 after problems and failures of this metal occurred due to metal embrittlement. Both materials were removed

---


18 See "SUPERIOR013492-SUPERIOR013494 - Clearance Inspection Report - Superior Spent Slide Valve 235726888_1."

19 See CSB report of Exxon/Mobile Torrance Refinery incident.


21 See: https://www.astm.org/DATABASE_CART/WITHDRAWN/A212.htm

22 See Attachment 2, ASTM A-212 Pressure Vessel Steel – A Case Against Continued Use, Dated June 20, 2011.
from the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code, Section VIII in 1968 as being unfit for thermal cycling. The following excerpt from the conclusion in Attachment 2 is particularly concerning:

"Pressure vessels manufactured from ASTM A-212 are still in use and the re-assessment for use under Fitness-for-Service rules requires that MDMT [minimum design metal temperature] be calculated under the newer ASME Code rules. Such evaluations will render the vessels, in all likelihood, not suitable for service under their original design specifications. The use of A-212 vessels under these temperature conditions is therefore not recommended and should only be pursued through the use of extensive risk assessment and additional hazard mitigation practices, such as employing operational controls (engineering and administrative) by limiting personnel exposure to the area of probable hazard and containing the effects of such a hazard if it were to occur. The question of continued use should not be considered on the basis of need, but rather personnel safety and liability."

Metallurgical testing of pieces of the failed absorbers, performed by the OSHA Material Failure Team in October, 2018, positively identified them as A-212 (Primary Absorber) and A-201 (Sponge Absorber), and also indicated the presence of metal embrittlement (Figure 25).

![Figure 25: Metal fatigue cracking evident on the metal shell.](image)

Chemical analysis of scale deposits on pieces of the metal (performed by Baker Hughes) identified high concentrations of sulfur and iron, suggesting the presence of iron sulfide deposits in these vessels before the explosion and fire.

The National Board Inspection Code (NBIC), requires internal inspections or complete in-service evaluation of pressure-retaining items not to exceed one-half of the estimated remaining service life of the vessel or ten years, whichever is less. The NBIC further states regarding brittle fracture:

"Determining susceptibility to brittle fracture should be required as part of the overall assessment for evaluating remaining service life or to avoid failure of the pressure-retaining item during a pressure test. In order to carry out brittle fracture assessment,

---

23 See ASME BPVC 1968, Subpart C, Requirements Pertaining to Classes of Materials, pp 100-113. UCS-5(a) states: "All carbon and low-alloy steel material subject to stress due to pressure shall conform to one of the specifications given in Section II of the Code and shall be limited to those listed in Table UCS-23 except as otherwise provided in Pars. UG-10 and UG-11." ASTM A-201 (ASME SA-201) and ASTM A-212 (ASME SA-212) are not listed in the table or per Pars. UG-10 and UG-11, nor are they listed in subsequent revisions to the code.

24 See the National Board Inspection Code, 2013, Part 2, Inspection, Section 4.4.7(a).
mechanical design information, materials of construction and materials properties are to be determined. This information is required for pressure-retaining components in order to identify the most limiting component material that governs brittle fracture. Design information, maintenance/operating history, and information relating to environmental exposure shall be evaluated to determine if there is a risk of brittle fracture. When brittle fracture is a concern, methods to prevent this failure shall be taken. These methods could include changes to operating conditions and further engineering evaluations to be performed by a qualified engineer (metallurgical/corrosion/mechanical). Engineering evaluation methods to prevent brittle fracture shall be reviewed and accepted by the Owner-user, Inspector, and Jurisdiction, as required.\textsuperscript{25}

There is no indication that Superior Refining Company performed an assessment at any time of the vessel’s susceptibility to brittle fracture. Non-destructive testing by Wet Fluorescent Magnetic Particle (WFMT) was performed in April 2013 on top head/shell welds of the Primary Absorber,\textsuperscript{26} but this would not have identified brittle fracture issues with the A-212 metal (although this testing did find six linear indications in the welds tested that had to be ground out).

**Newly Revised Shutdown Operating Procedure Dated April 25, 2018**

As noted above, a revised shutdown procedure for the FCCU and GCU had been issued only a day before this incident. Operators interviewed indicated that since this was the first use of this revision they were not very familiar with the changes and had not been trained to the procedure. In fact, the morning of the incident is when they were first given a copy of the revised procedure and were assigned to perform specific tasks in the procedure.

A few steps in the procedure were likely factors related to this incident.

(b) (4)

In fact, based on interviews with the person on duty the day of the incident,\textsuperscript{27} was not aware that spent slide valve differential pressure (D/P) was an important parameter to monitor during the shutdown, and\textsuperscript{28} was not closely monitoring this D/P that morning during the shutdown.

\textsuperscript{25} See the National Board Inspection Code, 2013, Part 2, Inspection, Section 4.4.8.2(a) and (b).
\textsuperscript{26} See "SUPERIOR004667-SUPERIOR004670 15G-V08 Pri Absorber UTs 2013."
\textsuperscript{27} See "SUPERIOR002476-SUPERIOR002495 SOP Shutdown Steam Purge."
\textsuperscript{28} See "SUPERIOR001797-SUPERIOR001819 Shutdown Procedures."

\textsuperscript{27}(b)7(C)

Page 20 of 52
Further, the Universal Oil Products (UOP) operating procedure (the FCCU and GCU were UOP design), Section XI. *Normal Shutdown*, addresses the importance of spent slide valve D/P as follows:

(b) (4)

UOP, Section XII, *Emergency Procedures*, explains further:

(b) (4)

Having a means of confirming the presence of catalyst above the spent slide valve should also be critically important to confirm that the catalyst hasn’t drained through the worn spent slide valve, thus removing a safety-critical seal between the regenerator and the reactor (and of course equipment downstream of the reactor).

Of concern also to the inspection team was the absence of an adequate MOC in producing the modified procedure for this shutdown, which should have included review of the hazards and consequences of deviation in the procedure. Since it was known by the procedure writers that the spent slide valve could leak through, especially if catalyst was not above the gate, a consequence following the procedure as written was that air could enter the system if the gate did not provide a positive seal – leading to the possibility of a fire and/or explosion event. A competent MOC program should have caught this and the operating procedure should have been revised accordingly.

**Lack of Adequate Training**

Operators in the control room and in the field were performing activities to this newly revised procedure without adequate training to the procedure. As noted above, most of the operators were given the new procedure the morning of April 26 and were assigned their duties per the procedure. Although many of the steps in the new procedure were the same as previous revisions, there were new steps (and deleted steps), which contributed to this event, including the dumping of all catalyst above the spent slide valve into the regenerator.

**Lack of Supervision and Oversight in the Control Room**

Based on interviews with supervisors and managers, from 0530 to 1000 the morning of the incident, the supervisors and managers were seldom in the control room, and when they were in the control room, they were not monitoring the control board. The shift supervisor had been recently promoted (one week before the incident) and had spent most of his time in the alky unit prior to his promotion. This was his first turnaround in the FCCU and Gas Con Unit, and from

---

30 See “SUPERIOR013120-SUPERIOR013491 - UOP Operating Procedure obtained from UOP 2018-07-30.”
0530 to 1000 the shift supervisor spent most of his time in the field helping operators perform shutdown tasks.

The operations manager indicated that he understood the importance of keeping catalyst above the spent slide valve and the importance of monitoring the differential pressure during the shutdown. However, he indicated that he was in and out of the control room the morning of the incident, primarily overseeing setup of the planned chemical cleaning, which was to occur immediately after shutdown.

As noted earlier, this was the board operator's first turnaround and first experience with the shutdown procedure. It was not monitoring the spent slide valve differential pressure, and there was not a step in the new procedure indicating that the D/P was important to monitor.

Lack of Adequate Investigation and Response to Pre-Incident Events
Two booms were heard in the control room and by some workers in the field prior to the 1000 explosion on April 26, 2018. After the first boom, operators and supervisors stepped out of the control room to look for the cause, which they attributed to contractor work in the area (like a crane dropping a load), but without investigating further. The second of the two booms was heard and seen by operators and was the result of flammable materials travelling through the flare line – resulting in the flare lighting off. This was attributed to problems the manager had heard about occurring in the boiler house and SRU and again, was not investigated further.

It is not clear to the inspection team why this second event was not of significant concern and was not investigated further in light of the shutdown, which is known to result in serious events if not adequately monitored and performed. In fact, in this case Superior Refining Company had a 2018 Spring Turnaround Safety Bulletin issued that included the following:

(b) (4)

The boom heard and seen from the vent line to flare (and the flare itself) should have resulted in alarms going off (such as a high pressure alarm) in the control room. However, operators interviewed did not know if an alarm had occurred.

Of interest though is that even though alarms may not have occurred or could have been missed, continuous emission monitoring (CEM) equipment at the stack experienced an increase in average stack flow beginning at approximately 0850 when the flow had been at a maximum of 290 scfm (standard cubic feet per minute), flow climbed to 1405 scfm at 0908am then gradually dropping to 785 scfm at 0935 before then climbing to 1180 scfm at 0946am (Figure 26). This indicated to the inspection team that reliefs had lifted somewhere in the refinery, which also should have been investigated by Superior Refining Company employees.

---

31 See photos taken by the CSHO on 4/29/2018 of the site and of the incident planning. Photo number IMG 0760.
PSM INSPECTION INFORMATION

Most processes and areas of a refinery are PSM-covered due to the large quantity of flammable gases and liquids being processed in them, and Superior Refinery is no exception. (b)(C) is also PSM-covered when in quantities greater than its threshold of 1,000 pounds.

Superior Refining Company provided a list of PSM processes and quantities of highly hazardous chemicals (HHCs) in each process. A total of 22 PSM processes were identified with total quantities of HHCs on site of:

- HF
- Flammable Liquids

The processes selected for this PSM inspection at Superior Refinery were the FCCU and GCU.

PSM OBSERVATIONS AND DISCUSSION

The following observations and discussions are the cumulative result of onsite walk-arounds, interviews, discussions, and document reviews related to PSM. All 14 of the PSM elements were reviewed during this inspection, with emphasis given to questions from the Chemical NEP (Attachment 1).

---

32 See "SUPERIOR005074."
33 See "SUPERIOR006506-SUPERIOR006547."
Employee Participation
Superior Refining Company has an employee participation plan and encourages employee participation in development and revision of procedures, PHAs, and technical documents. Superior Refinery also has an internal web site, called "Superior Information System (SIS)," where information about PSM elements (including PHAs and recommendations) is shared with employees.

Process Safety Information (PSI)
As noted above the units chosen for this inspection were the Fluidized Catalyst Cracking Unit (FCCU) and the Gas Concentration Unit (GCU or Gas Con). Superior Refining Company was able to provide flow diagrams, P&IDs, materials of construction, electrical classifications, and process chemistry information. The HRT selected areas outside of the FCCU to verify the accuracy of P&IDs due to the extensive damage and hazards present in the FCCU, so P&IDs were checked in the Green Gas Unit (GGU).

This FCCU was constructed under an original Universal Oil Products (UOP) design in 1961. As such it was constructed using the standards and materials available at that time including metal alloys ASTM A-212 and ASTM A-201, which were used in the Primary Absorber and the Sponge Absorber respectively. Since the original installation, ASME has changed its criteria for steel plate used in the construction of pressure vessels. In 1967 ASME withdrew the classification of ASTM A-212 steel for the construction of pressure vessels due to its susceptibility to low temperature brittle fracture (see the "Absorber Materials of Construction" section above).

The inspection team could not find any documentation that showed the testing and maintenance of the Primary Absorber was any different from other vessels not constructed of ASTM A-212 and no evidence that the minimum design metal temperature (MDMT) had been recalculated using the updated ASME criteria. In addition, due to the low resistance to pressure changes, it could not be determined that any upper and lower set-points or heating and cooling rates had been adjusted to accommodate the propensity for brittleness of ASTM A-212 steel.

When reviewing the U-1 and R-1 forms for the Primary Absorber (15G-V8) it was noted that the original U-1 form only accounted for 3 nozzles and 3 manholes, while the current P&IDs showed 10 nozzles and 3 manholes. The employer only reported two other forms since the original and they were R-1 forms for corrosion repairs on July 12, 2010 and on July 12, 2013. Comparison of the U-1 form for the Sponge Absorber (15G-V9) with the current P&ID noted the same discrepancy with only 3 nozzles and 1 manhole originally, but 8 nozzles and 1 manhole at the time of the explosion.

This discrepancy indicated that other changes had been made to the pressure vessels between 1961 and 2010, but no updated information and no additional updates to the original U-1 form were provided by Superior Refining Company.

Refer to Attachment 1, Chemical PSM Primary Questions #5, 8, and 9 for additional observations and discussions related to PSI.

34 See “SUPERIOR005203-SUPERIOR005206-a,” and “SUPERIOR006506-SUPERIOR006547,” pg 37 of 42.
35 See “HUSKY000991-HUSKY000992.”
36 See “HUSKY000989-HUSKY000990” and “SUPERIOR004672-SUPERIOR004672 15G-V08 Pri Absorber R-1.”
Process Hazard Analysis (PHA)
PHAs were reviewed for both the FCC and the GC units. The original PHA for the GCU was completed in June 1995. The last update and revalidation was completed in December 2014. The original PHA for the FCCU was completed in May 1995. The last update and revalidation was completed in October 2016. These PHAs utilized HAZOP methodology, and the revalidations included layer of protection analyses (LOPA) as well. Teams for these PHAs included engineers and operators with specific experience and knowledge of the processes and were led by an employee who had training in the HAZOP method.

PHA findings and recommendations are tracked and followed to completion. However, of concern on the original PHAs was the length of time required to complete some of these findings and recommendations. For example, two of the recommendations in the original GCU PHA were to review the sizing of relief valves on the High Pressure Receiver and on the Debutanizer and were assigned to the Reliability System Study. These two recommendations were not completed until May 2007. Many other recommendations were also not completed until years after the PHAs were performed (many between 1998 and 1999, with some completed as late as 2003 and 2007). However, this problem has apparently been corrected as PHA revalidation findings and recommendations reviewed have now been found to complete in a timely manner (i.e., only those requiring design and procurement have remained open for longer than 6 months).

The FCCU and GCU original PHAs and revalidations contained very little information associated with shutdowns, despite these being recognized as particularly hazardous operations. These revalidations do include a node for maintenance activities and include one item in the Global Issues node about getting foreign materials in the system but do not consider the potential for air entering the system on a startup or shutdown. Regarding air getting into the reactor, the FCCU PHA revalidation includes two items:

Refer to Attachment 1, Chemical PSM Primary Question #4, 8, 9, 13, and 15, for additional observations and discussions related to PHA.

37 See "SUPERIOR004315-SUPERIOR004512."
38 See "SUPERIOR007635-SUPERIOR008003."
39 See "SUPERIOR007414-SUPERIOR004314."
40 See "SUPERIOR007033-SUPERIOR007474."
42 See "SUPERIOR007656-SUPERIOR007802 - Gas Con 2014 - Appendix E - PHA Worksheets" and "SUPERIOR007066-SUPERIOR007213 - FCCU 2016 - Appendix E - Sessions and PHA Worksheets."
44 See "SUPERIOR007066-SUPERIOR007213 - FCCU 2016 - Appendix E - Sessions and PHA Worksheets," pg 7107.
Operating Procedures
Superior Refining Company utilizes a computer based system for maintaining many of its process safety management programs. The Superior Information System (SIS) is used to store many of the process safety management procedures, including Standard Operating Procedure Policy/Procedure ADM – 0006,\(^{45}\) and the Standard Operating Procedures (SOPs). Each control room in the refinery has access to the SIS and any operator can access those programs by logging onto the system. Management and employee interviews all corroborate this practice. According to employee interviews, when a procedure is to be implemented the employees access SIS, print out the desired procedure(s), and then take the procedure(s) with them into the refinery.

Evaluation of the SOPs (such as the newly revised procedure in use during the shutdown, “FCCU, Gas Con, Merox, and C3C4 Splitter Shut-down,”\(^{46}\) listed step by step actions to be completed but only referred to the consequences of deviation and safe upper and lower limits located in a PSI document. These Safe Upper and Lower Limits tables and the consequences of deviation are located in SIS. ADM-0006, paragraph 4.0, C) states,\(^{(b)(4)}\)

The procedures rely on the DCS to provide feedback to the operators when upper and lower limits are reached by giving alarm and warning feedback to the Board Operator in the event that the process is approaching a limit or an emergency situation. The concern is that if there was a loss of power or instrumentation, would the SIS webpage be available and would any alarm setpoints still be able to be monitored and reacted to during upsets or emergency situations. The inspection team concluded that Superior Refining Company did not have a sufficient backup power system in place and that the SIS could be lost during power outages, and in the case of this incident and the SIS was not available in the FCCU control room for several days following power loss.

In addition to the above listed deficiencies, the newly revised shutdown procedure used for this shutdown was only approved the day before the shutdown began without the use of a Management of Change (MOC) process, with no training given to employees on the changes to the procedure (refer to the “Newly Revised Shutdown Operating Procedure Dated April 25, 2018” section above for more information).

Another issue of concern with the changes in the procedure was that new equipment and piping was staged in the FCCU in preparation for the new “green” shutdown (i.e., a new EPA requirement). Previously all leftover product that was still in the piping and vessels, that could not be sent to slop, was drained and/or vented to the atmosphere. The new procedure was to connect steam lines, purge the piping and vessels to slop, and then clean the system with a cleaning fluid to be collected in tanks for disposal. Employees interviewed stated that the area

\(^{45}\) See “SUPERIOR005207-SUPERIOR5211.”
\(^{46}\) See “HUSKY000526-HUSKY000548.”
\(^{47}\) See SUPERIOR003361-SUPERIOR003381.”
was very congested with the new equipment and piping, and that the new process required more contractors to be in the area.

Refer to Attachment 1, Chemical PSM Primary Questions #6, 7, 8, 9, 10, and 11 for additional observations and discussions related to operating procedures.

Training
Superior Refining Company had a written training procedure that addressed regulatory training, operator training and maintenance training, as well as specific procedures for training to different positions. Tests were administered for the positions, as well as refresher testing performed to ensure retention of competence. Tests must be passed with a minimum score of 85%. Area supervisors must also certify in writing at the end of the training that employees have the required knowledge, skills, and abilities to perform their job.

Emergency response team members received initial 40-hour HAZWOPER training with 8-hour refreshers each year, as well as extensive training in response to a variety of possible emergency events including fire response, spills and releases, injuries, security, radiation, rescue, and other events/responses.

Refer to Attachment 1, Chemical PSM Primary Question #12, for observations and discussions related to maintenance training.

Contractors
The facility has a Contractor Safety Supervisor whose duties are to coordinate contractor safety using ADM-0008 — Contractors. The company relies on the services of ISNetworld for a preliminary contractor safety review of basic safety and health programs, injury and illness rates, and experience modification rate (EMR). Once a contractor clears the ISNetworld criteria the refinery coordinates directly with the company for more particular training, certifications, and qualifications of the contract employees. Depending on the frequency of the contractors used by the refinery, the company or the refinery does the initial orientation followed by specific training requirements needed such as [b] (4) personal protective equipment use, etc. No specific issues were found with contractor safety in regards to Process Safety Management; however, sometimes the results of incidents, investigations, and/or complaints were not being reported timely to the contractors.

The maintenance department utilizes both Superior Refining Company employees and embedded contractors. Embedded contractors receive the same initial training as other contractors that are used at the site but then are supervised by Superior Refining Company supervisors thereafter. Once on site these embedded contractors receive the same training as Superior Refining Company employees.

---

48 See "SUPERIOR005220-SUPERIOR005226 - d & e" and "SUPERIOR001077-SUPERIOR001092."
49 See for example "SUPERIOR00862-SUPERIOR00865 - d - FCCU1STASSISTANTTRAINEECHECKLIST,"
"SUPERIOR008066-SUPERIOR008071 - d - FCCU2NDASSISTANTTRAINEECHECKLIST,"
"SUPERIOR008072-SUPERIOR008081 - d - FCCU2NDASSISTANTTRAINEECHECKLIST,"
"SUPERIOR008082-SUPERIOR008094 - d - FCCU3RDASSISTANTTRAINEECHECKLIST, and"
"SUPERIOR008095-SUPERIOR008099 - d - FCCUHEADOPERATORTRAINEECHECKLIST,"
50 See for example "SUPERIOR008944-SUPERIOR008949 - d - KN FCCU Operator Training - HO 3 YR 120312."
52 See "SUPERIOR005227-SUPERIOR005232."
Refer to Attachment 1, Chemical PSM Primary Questions #16 through 25, for additional observations and discussions related to contractors.

Pre-Startup Safety Review (PSSR)
Superior Refining Company conducts Pre-Startup Safety Reviews (PSSR) for every MOC, including for turnaround maintenance and repairs. The PSSR has a required checklist as part of the PSM Policy Procedure ADM-009, Pre-Startup Safety Review.\(^{63}\) No issues of concern were found with the PSSR process.

Mechanical Integrity
Superior Refining Company procedure ADM-0010, Mechanical Integrity,\(^{64}\) is the overriding procedure for their mechanical integrity (MI) program. The MI program includes the following:

(b) (4)

Superior Refining Company's program applies to all process equipment listed in the PSM standard (1910(i)(i) through (vi)).

Maintenance workers include both Superior Refining Company employees and embedded contractors. The embedded contractors are discussed in the contractor section above.

The refinery utilizes a computerized maintenance management system (CMMS, in this case the software used was SAP) to document and track all maintenance work performed. The work process requires preparation and approval of work orders before work begins. Review of work orders requested by the inspection team\(^{65}\) indicated that work orders provided adequate details and information for crafts to perform their work. Work orders were generated for preventive, predictive and breakdown maintenance and were categorized and prioritized for safety, shutdown, and other reasons.

Inspections and testing activities were performed under predictive maintenance work orders (PMs). These PMs were programmed in CMMS to open at prescribed frequencies based on manufacturer, regulatory and company experience. Review of PMs performed and based on employee interviews, open PMs have been completed at the required frequencies, are reviewed and further actions taken when necessary, and are documented in the CMMS program for historical purposes.

Relief devices have been repaired or replaced during major turnarounds every 5 years. Superior Refining Company contracts out some repairs but also has a certified relief device inspection and repair shop at the refinery. Inspection and repair documents provided by Superior Refining

\(^{63}\) See "SUPERIOR005233-SUPERIOR005234."
\(^{64}\) See "SUPERIOR005241-SUPERIOR005262 - k."
Company indicated to the inspection team that these inspections, repairs and replacements were occurring every five years according to their schedule.\textsuperscript{56}

The inspection team could find no instances other than with the spent slide valve leakage, where equipment deficiencies occurred and were not corrected before operation beyond acceptable design limits continued.

An MI deficiency found by the inspection team was in the quality control of maintenance materials, spare parts, and equipment used on repairs and replacements in the refinery. Superior Refining Company could not demonstrate that they have an adequate process in place to ensure the right materials, parts and equipment were being specified, purchased, provided to, and used by the crafts for repairs and replacements of PSM equipment.

Refer to Attachment 1, Chemical PSM Primary Question #1, 2, 3, 6, and 12 for observations and discussions related to vessel and piping inspections, emergency shutdown systems and controls, equipment taken out-of-service requirements, and maintenance worker training.

**Hot Work**

Superior Refining Company has two procedures related to hot work, Standard Practice Instruction (SPI) 23, Hot Work, and ADM-011, Hot Work Permits.\textsuperscript{57}

Hot work is divided into two groups, high energy and low energy hot work. Both types are included as part of the Safe Work Permit. High energy hot work requires a fire watch, inspection and cleanup of the area, a fire extinguisher, initial atmospheric monitoring, and "periodic testing of the hot work area as required by conditions."\textsuperscript{58} LEL must be below 5\% in order to perform high energy hot work. Low energy hot work has none of the listed requirements for high energy hot work, including no atmospheric monitoring or testing, only looking, listening, and smelling (referred to by Superior Refining Company as "LLS monitoring") throughout the duration of the low energy hot work. The procedures also list specific requirements for hot work in confined spaces and for hot work on vessels, exchangers, tanks and piping.

**Management of Change (MOC)**

Superior Refining Company has a procedure for the processing of MOCs – PSM Policy and Procedure ADM-0012.\textsuperscript{59} This procedure is kept on the SIS and is administered by the PSM Engineer.

\textsuperscript{56} See "SUPERIOR001834-SUPERIOR002475," "SUPERIOR003382-SUPERIOR003382," and SUPERIOR004546-SUPERIOR004612."

\textsuperscript{57} See "SUPERIOR001772-SUPERIOR001776 July 2016 Action Items."

\textsuperscript{58} See "SUPERIOR005381-SUPERIOR005381 Specification and Purchase Procedure" and "SUPERIOR005382-SUPERIOR005382 Warehouse and Inventory Control."

\textsuperscript{59} See "SUPERIOR001070-SUPERIOR001076 - SPI23 Hot Work" and "SUPERIOR005263-SUPERIOR005265 - I."

\textsuperscript{59} See "SUPERIOR001070-SUPERIOR001076 - SPI23 Hot Work" pg 1073.

\textsuperscript{59} See "SUPERIOR005235-SUPERIOR005240."
Although the MOC process as outlined in ADM-0012 appears to be adequate, two cases were found by the inspection team where the process was not used when it should have been.

- As discussed in the "Newly Revised Shutdown Operating Procedure Dated April 25, 2018" and the "Operating Procedures" sections above, a newly revised procedure, dated the day before this incident, was implemented for the FCCU, Gas Con, Merox, and C3C4 Splitter Shut-down. However, an MOC was not prepared and the MOC process was not followed for this revised procedure.
- The spent slide valve was operated for a period of time before this shutdown with leak-by due to erosion of the valve. This same condition had been discovered in 2008 and in 2013 during previous turnarounds. This represented a deficient condition, which should have been reviewed and evaluated by use of the MOC process before continuing operation, but was not.

Refer to Attachment 1, Chemical PSM Primary Question #6, for observations and discussions related to use of an MOC when the process is operated with a piece of equipment out of service.

Incident Investigation
Superior Refining Company follows an incident investigation procedure, which outlines the requirements for investigations of PSM incidents. Superior Refining Company has another procedure for investigating non-PSM incidents.

The PSM incident investigation procedure requires investigation of each process incident and a near miss is defined as...

A PSM incident is defined in the procedure as an...

Severity level guidelines are also included in the procedure and include accidents, injuries, near misses, equipment damage or failure, fire, release, and spill events.

Incident investigations must begin within 48 hours of the incident or near miss and must designate an incident investigation team leader. Team members...

Reports are filed in the PSM Incident Investigation software (part of the Superior Information System) and were provided to the inspection team.

---

62 See "SUPERIOR012640-SUPERIOR012646 - e - ADM-0013 Incident Investigation (2013-06-17)."
63 See "SUPERIOR009843-SUPERIOR009852 - SPI 20 Incident-Injury Reporting and Analysis (Non-PSM Incidents)."
Seven PSM incident reports were provided by Superior Refining Company, which were all of the PSM incidents that had occurred since 2015.\textsuperscript{64} This is significantly less incidents than at most PSM facilities inspected by the members of this inspection team. Reports of these incidents included required PSM information and were very thorough in their investigation.

Findings and recommendations are tracked on a PSM Incident Investigation Tracking Log\textsuperscript{65} and include more findings and recommendations than listed in the incident reports. These findings and recommendations are assigned to an individual with reasonable due dates, which all appeared to be completed by or before the due dates.

**Emergency Planning and Response**

Superior Refining Company has an extensive Emergency Response Action Plan\textsuperscript{66} which covers multiple emergency issues that may arise including, spills, \textsuperscript{b}(4) release, fires, and mutual aid responsibilities for oil spills. Superior Refining Company had in place pre-planned responses for fires in all areas of the refinery with equipment requirements and firefighting preferred methods.

Superior Refining Company provides various levels of firefighter training to all of the Emergency Response Team (ERT) members as well as 40 hour HAZWOPER training. On the day of the incident, the onsite ERT was pre staged for an upcoming blind flange installation as part of the shutdown procedure for the FCCU. After the explosion, the site ERT responded quickly, had the initial fire extinguished in under an hour, and were in the process of sweeping the initial explosion area when they observed asphalt flowing into the FCCU and Gas Con areas, including the area where the explosion occurred.

Immediately following the explosion all personnel, other than the ERT, evacuated their areas and assembled at their muster points. All personnel were accounted for quickly using the site badging computer systems. Alarms and radio communications to the operators were used for evacuating. Some workers were sent to other muster points due to the explosion and fires, and injured employees were transported by Superior Refining Company personnel to the awaiting ambulances for treatment.

During this process, asphalt from Tank 101 continued leaking out of the hole punctured in it by the initial explosion. Approximately two hours after the leak started, employees witnessed the asphalt fire start at the opening of the tank and spread along the already spilled asphalt. The site ERT utilized outside resources that arrived to assist firefighting efforts. One of those assets was a drone that the site ERT used in firefighting efforts for coordination of foam and water to extinguish the fire.

The response to this incident was excellent, and the ERT was commended for their efforts.


\textsuperscript{65} See "SUPERIOR012652-SUPERIOR012687 - e - PSM Incident Investigation Recommendation Tracking Log."

This system is good for providing information to Superior Refining Company employees but does not provide the information to contractors. As a result, contractors are not always informed timely of incident investigation results. This was confirmed by contact employee interviews.

\textsuperscript{66} See "SUPERIOR010056-SUPERIOR010202."
Compliance Audits
Compliance audits appeared to be done both comprehensively with all 14 elements of PSM reviewed, and thoroughly with an in depth review into many of the elements. Findings and recommendations were documented and tracked to completion. However, there are currently 9 of 32 open action items remaining from the July 2016 audit, with 8 of the 9 open beyond their due dates.  

- Tables for Instrumented Systems and their Functions like the one in the GGU unit Procedure 1309 should be incorporated in all procedures for consistency and easy reference. Due 12/31/2017.
- Emergency Operating Procedures were not found for the following areas: 93-Benzene, 99-Flare Caustic Scrubber.[1910.119(f)(1)(i)(E)] Due 6/31/2017.
- Develop and implement procedures for inspecting flare headers and vent lines. Due 10/1/2017.
- Document the rationale for the frequency of re-tubing or replacing of process heat exchanger tube bundles. Due 10/1/2017.
- Add minimum and maximum values to the MCC write-up forms. Due 10/1/2017.
- Document procedures used to assure maintenance materials, spare parts and equipment are suitable for the process. Due 10/1/2017.
- Verify that the appropriate authorizations and approvals have been obtained and documented to extend the inspection and testing of Pressure Relief Valve 93-SV-005 until the 2017 turnaround. Due 7/1/2017.
- Review the existing Hot Work Permit Procedure and evaluate the need for gas testing prior to allowing electrically powered and internal combustion engine driven equipment to enter a Class I Division 2 area. Due 11/1/2018.

Refer to Attachment 1, Chemical PSM Primary Question #14, for observations and discussions related to retention of the last two compliance audits.

Trade Secrets
Superior Refining Company has no trade secret issues but does have a manager assigned to this function in the event that they do change a process that might involve a trade secret. The FCCU is one of the original UOP designs and does not use a trade secret catalyst.

PROPOSED CITATIONS AND RECOMMENDATIONS

The following are HRT proposed citations and recommendations based on this report. The HRT recognizes that the AO in conjunction with the RO will decide and prepare the actual agreed upon citations and recommendations, along with proposed abatements as applicable.

(b) (5)

67 See "SUPERIOR001772-SUPERIOR001776 July 2016 Action Items."
(b) (5)
Attachment 1
Chemical PSM Primary Questions

Chemical List

1. Was the last inspection of each pressure vessel and piping circuit in the Selected Unit(s) conducted per its specific inspection procedure/plan? Select 3 pressure vessels and 3 piping circuits that contain HHC in the Selected Unit(s) for this evaluation. Yes, No, or NA. Comments.

Yes and No. Vessel inspection records were reviewed for the High Pressure Receiver, Primary Absorber, Sponge Absorber, FCC reactor and FCC regenerator. These are inspected during turnarounds on a five year or ten year frequency. However, in regards to the HP Receiver, Primary Absorber and Sponge Absorber, inspections did not include testing for brittle fracture qualities as required by the NBIC. This despite information that ASTM A-212 metal displayed brittle qualities with several failures having occurred in the industry. See the Absorber Materials of Construction section above.

Piping circuits were reviewed for pipe lines associated with the above vessels. Visual and UT inspections were last completed in 2016 and 2017. Isometrics were included with good thickness measurement locations (TMLs) selected. Visual inspections included review of pipe supports associated with the systems as required by API 570.

2. Do piping inspection procedures include appropriate piping inspection frequencies for each pipe or piping segment? Yes, No or NA. Comments.

Yes. Superior Refining Company PSM Policy and Procedure ADM-0010, Mechanical Integrity, 4.0(A), requires both piping and vessel inspections in accordance with API standards. As well, Superior Refining Company Quality Control Manual, Plant Inspection and Maintenance, dated 3/31/2017, discusses in detail the inspection procedures to be followed. Routine inspections were performed every five years in conjunction with the company's turnaround schedule. Inspections were more frequent for piping approaching end-of-life.

3. Do MI pressure vessel and piping inspection and test procedures specifically document the required qualifications of inspectors, examiners, contract inspectors, etc. that conduct vessel/piping inspections and tests? Yes, No, or NA. Comments.

Yes. Superior Refining Company Quality Control Manual, Plant Inspection and Maintenance, dated 3/31/2017 specifically lists the requirements:

(b)(4)

---

69 See "SUPERIOR005383-SUPERIOR005384" through "SUPERIOR005602-SUPERIOR005606."
70 See "SUPERIOR012545-SUPERIOR012617 - 1 FINAL QC Manual 2nd Ed uncntrid all Exhibitsigned 234868964_1."
This control manual is quite extensive and also lists the API, ASME and NBIC standards associated with the inspections and tests to be performed. Superior Refining Company is to be complimented for this excellent document.

4. Does the initial PHA of the Selected Unit(s) consider/address human factors during non-routine operations including deviations from steps of the written startup, shutdown, and online maintenance procedures? Yes, No, or NA. Comments.

Yes. The revalidated FCCU and GCU PHAs address human factors with an extensive checklist of questions including a list of questions associated with procedures.71 The checklist includes verifying that there are written startup and shutdown procedures that are updated, accurate, and easy to read. The checklist also includes questions regarding training of operators and maintenance workers via pre-job analysis meetings for non-routine tasks, as well as asking for assistance when needed and stopping work when safety is in doubt. However, a recommendation is in order to more specifically address the human factors in these situations.

5. Has the employer compiled information pertaining to relief system design and design basis? Yes, No, or NA. Comments.

Yes and No. The inspection team reviewed the design calculations for several relief valves in the FCCU and GCU. The design basis’s and design calculations appeared to follow ASME BPVC and API 520 standards. However, two problems were found with the calculations used on 15G-SV006, High Pressure Receiver Relief Valve.72

d) Based on P&IDs and flow diagrams, this relief valve protects piping and vessels from the discharge of the gas compressors to the stripper column (including the HP Receiver Condensers, HP Receiver, HP Receiver Water Knock-Out Pot, Primary Absorber, Sponge Absorber, and Stripper Column). However, the calculation sheets indicated that only the HP Receiver, Primary Absorber, Sponge Absorber and KO Pot were included in the calculation (and did not include piping systems). As a result, this relief valve was undersized for the required protection needed in an external fire event (which was one of the basis used in this case).73

e) The backpressure calculation performed included discharge piping and elbows only to the flare header (measuring less than 30 feet total length). However, the flare header continues for over 100 feet further to the flare and this piping should be included in the calculation. The backpressure calculation performed74 indicated a pressure drop of 11.7%, which is above 10% as required by API 520, and will be higher once recalculated with the flare header piping included.

The inspection team also reviewed an Inter-Office Correspondence dated June 3, 2009 that included design calculations for the flare.75 Since these calculations were done, it is possible that some processes could have been removed from service. As well, other processes have been added (for example the Green Gas Unit). The flare design calculations also consider outside fires in separate, different areas of the plant and may not include a worst case

71 See “SUPERIOR007372-SUPERIOR007382 - FCCU 2016 - Appendix I - Checklists” and “SUPERIOR007922-SUPERIOR007933 - Gas Con 2014 - Appendix I – Checklists.”
72 See “SUPERIOR008349-SUPERIOR008472 15G-SV006 SIZING.”
73 See calculations on pp 8405-8412 of “SUPERIOR008349-SUPERIOR008472 15G-SV006 SIZING.”
74 See calculation on pg 8411 of “SUPERIOR008349-SUPERIOR008472 15G-SV006 SIZING.”
75 See “SUPERIOR011840-SUPERIOR011846 - h - Flare Capacity Study.”
outside fire scenario that could affect two or more areas at the same time. Based on the calculations provided, the flare is under-designed for a worst case fire scenario (see API 521 and 537), has not been redone for many years, and does not include new processes installed since the design was completed.

6. **Is there a written operating procedure and MOC for when the Selected Unit(s) have been run when a relief device, flare, incinerator, thermal oxidizer or scrubber is out-of-service? Yes, No, or NA. Comments.**

   Yes. Superior Refining Company has a specific procedure addressing critical alarm and emergency shutdown device bypasses. Devices include safety interlock systems designed to shut down refinery equipment. This procedure requires the use of a Critical Alarm/ESD Bypass Form that must be approved and signed by the shift foreman or area superintendent. The procedure requires that the Head and Board Operators read and understand the form and any affected procedures, and that the form be posted in the operator logbook.

   Equipment such as relief devices, flares, incinerators, thermal oxidizers, and scrubbers can only be taken out of service by use of an MOC as explained in the Superior Refining Company MOC procedure, ADM-0012. The procedure defines a change.

   

   7. **Do the operating procedures and safe work practices for the Selected Units include FRC requirements when employees are exposed to flash fire hazards? Yes, No, or NA. Comments.**

   Yes. The minimum requirements for PPE, including FRCs, were listed in the SOPs, and any additional work outside the normal scope of the SOP required the use of a Safe Work Practices Procedure and possibly Confined Space Permits and Procedures and even Hot Work Procedures.

8. **Does the PSI, PHA, and operating procedures for the Selected Unit(s) address hazards/consequences of the loss of agitation for equipment that is designed to be agitated (e.g. reactors, storage tanks/vessels)? Yes, No, or NA. Comments.**

   NA. The selected units reviewed during this inspection (FCCU and GCU) do not include agitators, mixers, or other mixing equipment.

9. **Does the PSI, PHA, and operating procedures for the Selected Unit(s) address hazards/consequences of the loss of gas for purging, blanketing, or inerting of equipment (e.g. process equipment, storage and process tanks/vessels, etc.)? Yes, No, or NA. Comments.**

   Yes. The GCU PHA revalidation includes an item for loss of nitrogen but with no consequences listed. Both the FCCU and GCU PHA revalidations include a node for purging and inerting with one item listed for inadequate purging that could lead to possible fire and

---

76 See "SUPERIOR010023-SUPERIOR010026 - SPI54 CRITICAL ALARM ESD BYPASS."
77 See "SUPERIOR005235-SUPERIOR005240 - j."

Page 39 of 52
injury. Safeguards are to follow shutdown procedures, LOTO, and confined space monitoring.

10. Are there written operating procedures for when operations are routinely (normal operations) conducted under automatic controls but are then changed to manual mode? Yes, No, or NA. Comments.

Yes. These are done when needed as part of the MOC process. The MOC procedure Attachment B requires that three supervisors approve the emergency MOC for the changes to the process/procedure until the loss of controls problem can be fully identified. This may require additional operators until the problem is corrected.

General List
11. Do operating procedures address the elements required by paragraph (f)? Yes, No, or NA. Comments.

Yes. ADM-0012 Management of Change Procedure has a checklist at the end that references to each 29 CFR 1910.119 standard paragraph and identifies which section of the procedure covers that standard.

12. Does the employer train each employee involved in maintaining the mechanical integrity of the process in:
An overview of that process and its hazards? Yes, No, or NA. Comments.

Yes. All new employees receive training in the 14 elements of PSM before entering the refinery. An overview of the processes is then provided to maintenance craft, new hires and transfer personnel. Once working in the refinery, maintenance workers cannot perform work without completing a Safe Work Permit (SWP) with the operators in the area. The SWP process requires a discussion of the hazards in the area but does not include a discussion of the process itself. Maintenance workers interviewed demonstrated a good knowledge of the processes at the refinery.

The procedures applicable to the employee’s job tasks to assure that the tasks can be performed safely? Yes, No, or NA. Comments.

Yes. Training is provided to maintenance workers and workers can progress to three different levels in their craft based on their skills, the highest being a “technician” level. Training is provided by completion of videos for certain activities, in-house technical training, and outsourced technical training. Technical operating and maintenance manuals are also available to the workers and work orders are issued with instructions on how to perform the job(s). Maintenance workers interviewed demonstrated a good knowledge of the jobs discussed with them by the inspection team.

13. Do employers provide access to PHAs and all other information required to be developed under the standard? Yes, No, or NA. Comments.

78 See "SUPERIOR005235-SUPERIOR005240
79 See "SUPERIOR005220-SUPERIOR005226 - d & e" pg 5221.
80 See "SUPERIOR005241-SUPERIOR005262 - k" pg 5245.
81 See "SUPERIOR005266-SUPERIOR005276 – m,” Safe Work Authorization.
82 See "SUPERIOR005241-SUPERIOR005262 – k,” Mechanical Integrity.
Yes. Superior Refining Company provides access to this information on a “Superior Information System (SIS)” website, available to all employees at the refinery. The inspection team reviewed the SIS on a local computer and found the information to be adequate. The page was also set up in a way that made it easy to find and access the information.

14. Has the employer maintained the two most recent compliance audit reports for the selected unit(s)? Yes, No, or NA. Comments.

Yes. The last two compliance audits for Superior Refinery were performed in August 2013 and July 2016. The audits in both cases were conducted by consultants from Professional Safety Services with one person from the refinery participating and providing the requisite knowledge of the covered processes.

15. Has the employer addressed facility siting in the most recent PHA? Yes, No, or NA. Comments.

Yes. Facility siting was also addressed on the original PHAs reviewed and performed in 1995. Recommendations from these original PHAs resulted in the performance of a facility siting study in 1998. As the result of the facility siting study, the FCCU control room was relocated and a new explosion resistant structure built. This structure was essentially undamaged from the explosions and fires associated with this event. Superior Refining Company has been highly complimented by the inspection team for this work.

Contractor List

16. Interview 1-2 contract employees from each contract employer performing covered work in/near the Selected Unit(s). Are the employees aware of and do they understand the hazards related to their work and the process? Yes, No, or NA. Comments.

Yes. The employer had written procedures and programs, including but not limited to, lockout, confined space, hot work, process opening procedures, etc. Including ADM-0008 Contractor PSM Policy and Procedure (SUPERIOR005227-005232) dated July 18, 2013 which covered how the facility implemented the required sections of 1910.119(h)(1)-(3). See this policy for more detailed information. Based on this inspection it was indicated that this policy was being adhered to and no citable deficiencies were noted.

Contractor’s safety and health procedures and written programs were reviewed by Superior Refining Company (SRC) prior to contractors working on-site. Additionally, SRC held initial and subsequent training for contractors working on-site. SRC provided to OSHA some information on contractor training as well as written programs and policies that included: Superior Refinery LDAR (leak detection & repair) Program, Life Saving Rules, Contractor Site Safety Orientation and Quiz, and the Contractor Safety and Procedure Manual. Interviews with contractor employees noted training annually on sulfur recovery unit, alkylation, fresh air (blinding and line breaking), LOTO, pre-job work, hydrofluoric acid (HF) hazards, evacuation, permit process, etc.

Training on potential fire, explosion, and toxic release hazards were covered with contractors. Emergency action plans were covered with contractors. Topics indicated as covered included site safety orientation and tests to include chemical safety; emergency action plan and entry/exit procedures; contractor safety procedure manual; pre-construction

---

83 See 4 documents, “SUPERIOR001730 through SUPERIOR001776.”

Page 41 of 52
unit safety review; additional training for sulfur recovery/tail gas unit (hydrogen sulfide); HF alkylation unit with test; pre-construction job hazard analyses as needed; and safe work authorization (SI01) to include the safe work permit system.

SRC had a safe work permit program (SWP) in which contractors would fill out a permit prior to being able to start work. These permits included hot work, confined space, LOTO, and any other work being performed. The operators were typically the ones to issue the permits. SWPs were to be filled out and turned in the day prior to work commencing so plant personnel could review ahead of time. Permits were provided from 4/20/18-4/26/18.

A sample of filled out confined space permits was provided from 4/9/18 to 4/20/18 with no issues noted

SRC utilizes two hot work programs, one for high energy hot work and another for low energy hot work. Low energy hot work requires no atmospheric monitoring or testing even though a fire or explosion can occur with low energy ignition sources in the presence of a fuel. It was identified that certain pieces of equipment such as vehicles were indicated as low energy which should be considered as high. Permits from 3/9/18 to 4/18/18 were provided. The inspection team recommends that initial atmospheric monitoring be required prior to utilization of low energy devices.

17. Have contract employers assured that each contract employee is trained in the work practices necessary to safely perform his/her job? Yes, No, or NA. Comments.

Yes. SRC evaluated their contractors initially prior to them performing work on-site and annually. The employer utilized ISNet to pick contractors based on their written safety programs; OSHA violations and history; safety and health records to include experience modification rate, days away restricted or transfer rate, fatalities, incident rate, insurance; and a Superior Qualification questionnaire was performed. Documentation for a random number of contractor evaluations was requested (evaluations were provided for Houston Services, Benson Electric, Stack Bros., and Jamar Company). SRC also kept OSHA injury and illness logs for contractor employees, which were provided from 2015 to the date of the incident. 1910.119(h)(3) elements were reviewed prior to contractors working on-site through John Rainha and the ISNet World System. Employers had to show they trained their employees and had safe work practices and procedures in place; additionally the refinery provided training as indicated above.

18. During walk-around inspections in the Selected Unit(s), observe contractors' entry and exits from the Selected Unit(s). Is the host employer effectively monitoring and controlling the entrance/exit and work ("presence") activities of contractors in the Selected Unit(s)? Yes, No, or NA. Comments.

Yes. Contractors are all issued badges that have to be scanned to enter and exit the facility. This system was tested as a result of the mandatory emergency evacuation when the muster point personnel made a physical count of the contractors who "scanned" in and out to verify all personnel were accounted for.
19. Randomly select 5 contract employees. Did the contractor employer document these employees’ training, including the means used to verify employees’ understanding of the training? Yes, No, or NA. Comments.

Yes. Training information for contractors was provided as well as the “Site Safety Orientation Quiz” that contractors take after their on-site training.

20. Does the host employer periodically evaluate the performance of contractors to assure that the contractor’s employees are following ALL the obligations required of contractors per 1910.119(h)(3)? Yes, No, or NA. Comments.

Yes. See question #17.

21. Identify two contractors currently working on the Selected Unit(s) or that have worked on the Selected Unit(s) in the past. Did the host employer obtain and evaluate the contract employer’s safety information and programs before allowing them to work on the Selected Unit(s)? Yes, No, or NA. Comments.

Yes. See question #17.

22. Has the contract employer assured that each contract employee is instructed in the known potential fire, explosion, or toxic release hazards related to his/her job and the process, and the applicable provision of the emergency actions plan? Yes, No, or NA. Comments.

Yes. See question #16.

23. Interview at least two contract employees, do they know and understand what the employee alarms mean at the facility? For example, a certain number of blasts of the facility employee alarm system mean one thing, while a different number of blats mean another. Yes, No, or NA. Comments.

Yes. See question #16. Employee interviews indicated they knew what the different alarms were and noted emergency response training was covered yearly with mock drills. Training muster point locations were reviewed. There were also different alarms used to identify different emergency events, which were tested monthly. Interviews also noted that orientation training covered emergencies for the sulfur recovery unit, fire watch, confined space, etc.

24. Has the contract employer assured that each contract employee follows the safety rules of the facility including the safe work practices required by paragraph (f)(4) of the PSM standard? Yes, No, or NA. Comments.

Yes. See #16 – Safe work permits section above.

25. Has the employer maintained a contract employee injury and illness log related to the contractor’s work in process areas? Yes, No, or NA. Comments.

Yes. Each contractor employer is required to maintain injury and illness logs and report them to the host contractor when required. These logs can be provided in person to the host
contractor safety liaison person and also through the ISNetworld service where the logs are posted as part of the evaluation of contract employers. See question # 17.
References:
10. SSC-204, Simulated Performance Testing for Ship Structure Components. Southwest Research Institute, 1970
13. ASME Section VIII, Div 1. Figure UCS-66.

Copyright Notice: Figures used in this publication are included under the "Fair Use" clause of the Copyright Act of 1976 as amended in 1992, within the context of non-profit, educational purpose use only.