BSEE Panel Report 2018-002

Investigation of November 12, 2016 Fire with Multiple Injuries
Lease OCS-30206, Grand Isle Area-Block 115

Gulf of Mexico Region, New Orleans District
Off Louisiana Coast

August 29, 2018

U.S. Department of the Interior
Bureau of Safety and Environmental Enforcement

BSEE's National Investigations Program is administered by its Safety and Incident Investigations Division in Washington, D.C. Panel investigations, an integral tool for safety improvement, are chaired by division and regional staff, and conducted in coordination with region and district staff.

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Abbreviations and Acronyms

AIT– Autoignition Temperature
ANSI– American National Standards Institute
API– American Petroleum Institute
ASME– American Society of Mechanical Engineers
BOEM– Bureau of Ocean Energy Management
BPVC– Boiler & Pressure Vessel Code
BS&W– Basic Sediment & Water
BSEE– Bureau of Safety and Environmental Enforcement
BSL– Burner Safety Switch – Low
CFR– Code of Federal Regulations
ESD– Emergency Shutdown
EW– Ewing Bank
FRC– Flame Retardant Clothing
GI– Grand Isle
GOM– Gulf of Mexico
HSE– Health Safety and Environmental
I&E– Instrumentation & Electronics
IP– Injured Person
JSA– Job Safety Analysis
LACT– Lease Acquired Custody Transfer
LFL– Lower Flammable Limit
LSL– Level Safety Switch – Low
LSH– Level Safety Switch – High
MC– Mississippi Canyon
NFPA– National Fire Protection Association
NTL–Notice to Lessees
OCS– Outer Continental Shelf
OEM– Original Equipment Manufacturer
OIM– Offshore Installation Manager
PE– Professional Engineer
PIC–Person in Charge
POB– Personnel on Board
PPE– Personal Protective Equipment
PSI– Pounds per Square Inch
PTW– Permit to Work
PV– Pressure Vacuum
RIO– Remote Input/Output
RP– Recommended Practice
RUE– Right-of-Use and Easement
SAFE– Safety Analysis Function Evaluation
SDS– Safety Data Sheet
SDV– Shutdown Valve
SEMS– Safety and Environmental Management Systems
SimOps– Simultaneous Operations

SOP– Standard Operating Procedure
SSE– Short Service Employee
STD– Standard
SWA– Stop Work Authority
SWP– Safe Work Practice
TSE– Temperature Safety Element
TSH– Temperature Safety Switch – High
UFL– Upper Flammable Limit
USC– United States Code
UWA– Ultimate Work Authority
VRU– Vapor Recovery Unit
WTL– Work Team Leader

Executive Summary

On November 12, 2016, three Wood Group Operators contracted by LLOG Exploration Offshore, L.L.C. (LLOG) at their Grand Isle Area (GI) Block 115 "A" platform (the platform) suffered burn injuries while preparing to eliminate an emulsion pad that formed in the platform's heater treater. The injuries occurred due to a fire that began in the vicinity of the heater treater when a flammable gas mixture migrated into the area and reached a heat source, completing the necessary requirements for ignition and sustainment of fire.

Since resuming production in March 2016 following structural modifications, excessive basic sediment and water (BS&W) caused frequent issues with maintaining production on the platform. In early November 2016, LLOG installed a steam unit, which resolved some of their BS&W issues. However, on the day of the incident, a mechanical malfunction occurred to the steam unit, resulting in an excessive emulsion pad in the heater treater that prevented LLOG and Walter Oil & Gas (WOG) from producing sales quality oil. To address this issue, crews usually drained the emulsion pad from the heater treater to one of the oil tanks on the cellar deck below, and then used a bucket to batch treat the emulsion with a chemical emulsion breaker.

The crew involved in the incident was preparing to troubleshoot the emulsion pad when the fire occurred. They made no attempt to isolate the heater treater, nor did they secure the fire tube burners. Without draining the emulsion pad, one operator, located adjacent to the heater treater flame arrestors on the platform's main deck, prepared to batch treat the dry oil tank using a hose from a chemical tank on the main deck to the dry oil tank located on the cellar deck below. Another operator opened a hatch on the top of the dry oil tank to receive the hose. This action released a flammable vapor cloud that extended upward to the main deck.

Within a minute of the hatch being opened, the operator on the main deck, as well as another operator who had just walked up to him, described witnessing a flame coming from the general location of the heater treater flame arrestors. The flame ignited the existing flammable vapor cloud in the vicinity of the heater treater flame arrestors.

The operator preparing to batch treat was engulfed in flames, but managed to escape the fire by running toward the southwest corner of the platform. The operator on the cellar deck felt the flame around him before closing the hatch and jumping down to safety. The operator who had just arrived fell backward, got up, pushed the platform emergency shutdown (ESD) button and announced the fire over the radio. Both operators on the top deck, as well as other personnel on shift throughout the platform, responded to assist with extinguishing the fire. Individual accounts indicated that the fire lasted anywhere from a few seconds to several minutes.

The three injured operators suffered a combination of first and second degree burns to their hands, arms and face; the most severe of which were to the operator preparing to batch treat. Platform personnel assisted with first aid treatment while the Person-in-Charge (PIC) called for evacuation of the injured employees to a hospital on shore. All three were treated and released within two days of the incident.

The Bureau of Safety and Environmental Enforcement (BSEE) convened a panel to conduct an investigation into the cause(s) of the incident and issue a report of its findings, conclusions and recommendations. The panel, comprising BSEE professionals, identified the following direct and indirect incident-causal-factors that may have contributed to the direct causation and totality of the incident:

Direct Cause

- The fire occurred when a flammable gas mixture, which was released through the thief hatch on the dry oil tank, migrated into the left fire tube of the heater treater, where it contacted either the left fire tube flame or the left burner pilot flame. This flame likely propagated through a gap in the mating flange between the left flame arrestor housing and the heater treater, igniting the flammable gas mixture in the surrounding atmosphere.

Indirect Causes

- Personnel failed to sufficiently mitigate hazards.

- Lack of sufficient engineering controls.

- The gap in the flame arrestor/heater treater mating flange was likely caused by improper installation and/or assembly of the mating flange.

Contributing Factors

- Failure to follow OEM recommendations, industry recommended practices, and industry standards.

- Personnel failed to adhere to permitting requirements.

- The hazard analysis performed for the work to eliminate the emulsion pad was insufficient, as the incident crew not only neglected to perform a JSA, but also failed to hold a pre-job safety meeting.

- The improper use of PPE resulted in injuries that may not have occurred had proper PPE procedures been followed.

- Daily safety meeting failed to sufficiently address operations and hazards on the day of the incident.

- Insufficient supervision.

- Poor communication.

- Unfavorable environmental conditions.

- Equipment failure

The BSEE Panel makes recommendations in an effort to further promote safety, protect the environment, and conserve resources on the U.S. Outer Continental Shelf (OCS). The following listing contains some of the key recommendations identified as a result of the investigative findings detailed within this report:

- Consider the location(s) of fired elements relative to potential gas releases when performing facility-level hazard analyses.

- Consider the use of permanent containment systems for vessel draining and chemical treatment.

- Consider conducting visual inspections of natural draft burners, ensuring airtight integrity between flame arrestors and fire tubes.

- Consider the use of a portable gas detector when operating in the vicinity of fired vessels.

- Consider increasing operator supervisory presence when using contractor-employed supervisory personnel during non-routine operations.

- Consider ensuring production SOPs are used for site specific equipment and/or conditions.

- Ensure operators are familiar with, and adhere to, OEM instructions regarding start-up, operations, maintenance, and inspection of fired vessels and associated safety devices.

- Consider instituting applicable industry standards into inspection programs, SOPs, and SWPs.

- Ensure all contractor personnel engaged in production operations are knowledgeable regarding operator SWPs.

- Ensure that all company, contractor, and visiting personnel properly wear PPE where the potential exists for thermal exposure from fire, and that the PPE selected for the job reflects the probable and possible hazards of the job.

Introduction

Authority

Pursuant to 43 United States Code (USC) § 1348(d)(1), (2) and (f) [OCS Lands Act, as amended] and 30 Code of Federal Regulations (CFR) Part 250 [Department of the Interior regulations], the BSEE is required to investigate and prepare a public report of this incident.

BSEE's Gulf of Mexico (GOM) OCS Region, New Orleans District office was notified of the incident on November 12, 2016. By memorandum dated November 15, 2016, the investigation panel (the panel) was formed and initiated its investigation of the incident. The panel included:

Harold Griffin – Chairman, Petroleum Engineer, Office of Incident Investigations, GOM OCS Region;

Ashton Blazquez – Petroleum Engineer, Production Operations Section, New Orleans District, GOM OCS Region;

Ross Laidig – Special Investigator, Safety and Incident Investigations Division, Headquarters;

Pierre Lanoix – Inspector/Accident Investigator, Production Operations Inspection Unit B, New Orleans District, GOM OCS Region;

Simon Zippert – Petroleum Engineer, Office of Safety Management, GOM OCS Region.

Background

The incident occurred on LLOG's "Seahorse" Platform A (the platform), situated in Grand Isle (GI) Block 115, surface lease OCS-G 35612. The surface lease covers approximately 5,000 acres on the OCS, within the GOM, off the Louisiana coast (*see Figure 1*). The surface lease was purchased in 2015 by Apache Shelf Exploration LLC (Apache) as the 100 percent working interest owner and lease group operator. While the surface lease was owned by Apache, the platform was maintained by LLOG under a Right-of-Use and Easement (RUE) authorization (OCS-G 30206) approved by BOEM since April 2012 in order to process production.

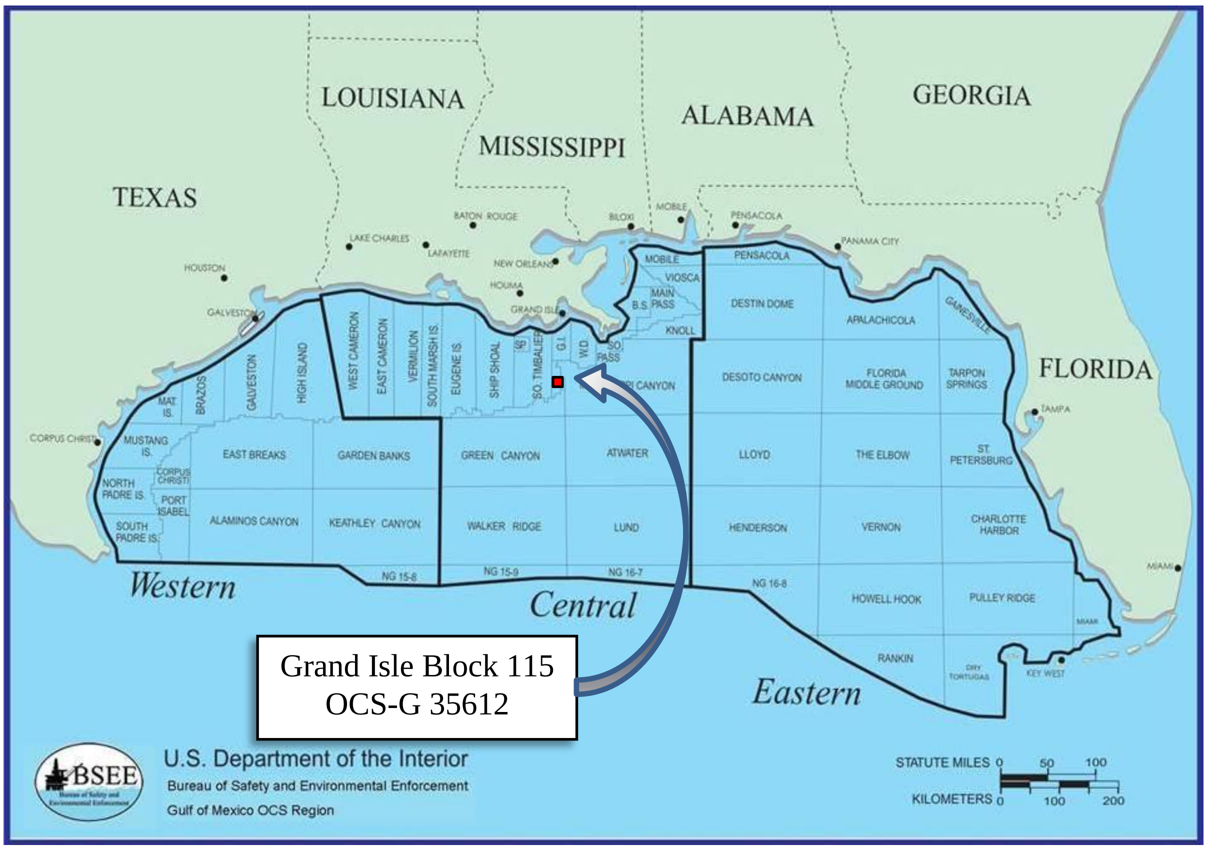

Figure 1: Location of Lease OCS-G-35612, GI Block 115

The platform is a four pile, fixed steel structure with four well slots. It was originally installed in 1997 by British-Borneo Exploration, Inc. The water depth at the GI Block 115 location was approximately 366 feet, and the distance from shore was approximately 54 miles.

LLOG's production to the platform came from three subsea (SS) wells located in three different blocks and bottom leases in the Mississippi Canyon (MC) area, all operated by LLOG (see *Figure 2*). Walter Oil and Gas Corporation (WOG) also used the platform for production operations, producing from one subsea well located in Ewing Bank (EW) Block 878.

Area	Block	Well	Bottom Lease No.	Lease Operator
MC	705	SS001	G31521	LLOG Exploration Offshore, LLC
MC	707	SS001	G25103	LLOG Exploration Offshore, LLC
MC	751	SS001	G33175	LLOG Exploration Offshore, LLC
EW	878	SS003	G18169	Walter Oil & Gas Corporation

Figure 2: Relevant Lease Details

All oil production left the platform via a pipeline owned by Shell Pipeline Company LP. A crossing gas pipeline also ran through the platform. LLOG, as the RUE holder and operator of the platform, was responsible for ensuring all operations performed at the platform were conducted in compliance with all applicable regulations.

Companies Involved

LLOG used contractors to perform all of its operations and did not have a company employee on the platform on November 12, 2016. At the time of the incident, a total of 17 contractor personnel from seven different companies were aboard the platform. The primary contracted service provider companies involved with relevant operations were:

- Danos, who provided Persons-in-Charge (PICs) for the platform;
- Wood Group Production Services Network (WGPSN), who provided operators and mechanics for LLOG;
- NALCO Champion, who provided flow assurance support for LLOG;
- Island Operating Company, who provided A/B/C Operators for WOG production;
- Canal Energy Services, who provided steam unit operators.

Production Operations

Production operations on the platform were conducted on a 24-hour basis using two primary 12-hour shifts, with shift changes scheduled at *06:00 am (*day shift) and *06:00 pm* (night shift). One of the operators was performing a supplemental rotation, and was working from noon until midnight. The PIC, employed by Danos, was the designated Ultimate Work Authority (UWA) for the platform. The remainder of LLOG's production team (one mechanic and five operators covering day and night shifts) was employed by WGPSN. WOG's production team, employed by Island Operating Company, monitored operations for the 878 well.

LLOG documentation depicts the relevant supervision and organizational structure at GI Block 115 "A", as shown in Figure 3. The Compliance Manager and Health, Safety and Environment (HSE) Specialist work out of LLOG headquarters office. They manage compliance policies and personnel issues for field operations. The Compliance Technician (CT) assigned to the platform, who primarily handles American Petroleum Institute (API)

Recommended Practice (RP) 14C[1] compliance issues for multiple facilities, was not present on the platform at the time of the incident.

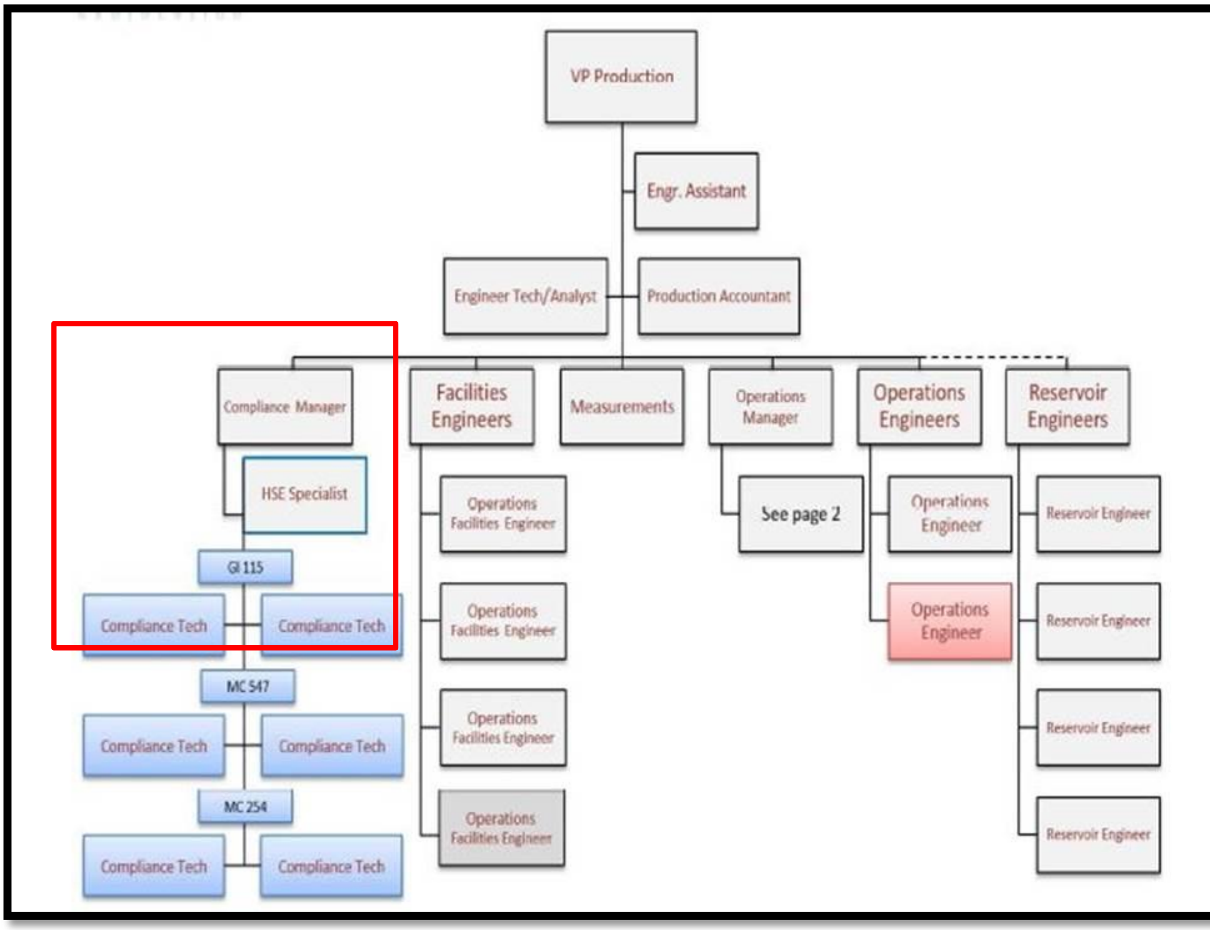

Figure 3: LLOG Organizational Structure for GI Block 115 "A"

Relevant Production Equipment

<u>Heater Treater</u>: When a crude oil is produced from a reservoir, the reservoir often contains water. The water must be separated from the oil, treated, and disposed of properly. Since sellable crude oil specifications limit the amount of allowable basic sediment and water (BS&W), further separation of water from crude oil may be required. Under certain conditions, water and oil will form an emulsion, which is the dispersion of droplets of one liquid in another insoluble or immiscible liquid.

Demulsification, the process of breaking emulsions, consists of two distinct steps. The first step is coagulation, where the droplets clump together, forming aggregates. The second step is coalescence, an irreversible process in which the aggregates fuse together,

[1] API RP 14C, "Analysis, Design, Installation, and Testing of Safety Systems for Offshore Production Facilities"

forming larger droplets. Eventually, the droplets will become large enough to separate from the immiscible liquid.

Of the methods used to break emulsions, chemical treatment is the most common. Another method is the addition of heat. Heating increases the frequency of coalescence, thereby accelerating the demulsification process. A heater treater, like the one used on the platform (*see Figure 4*), provides a means of heat and separation, with chemical treatment occurring in separate oil tanks. The heater treater on the platform uses two natural draft heaters, each of which consists of an air intake (which houses a flame arrestor), a burner assembly, a fire tube, and an exhaust stack (which houses a stack arrestor). In addition to the flame arrestors and stack arrestors, the heater treater on the platform contains all safety devices required by 30 CFR 250 Subpart H.

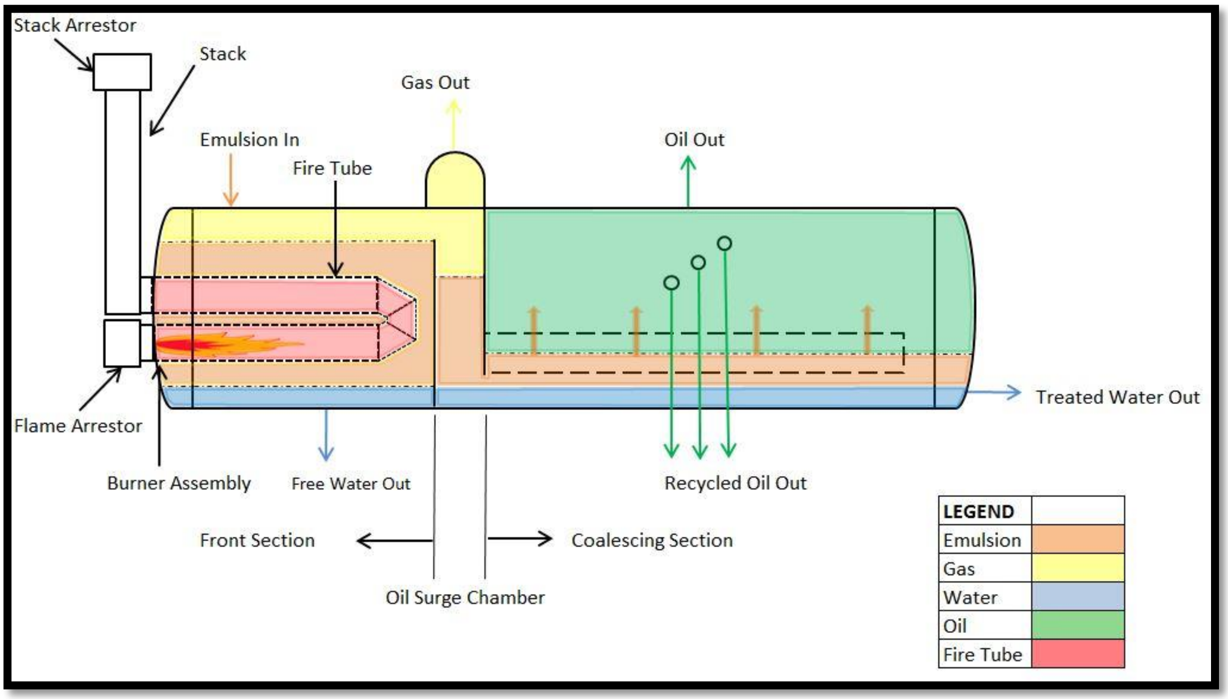

Figure 4: Representative Illustration of Heater Treater

The burner assembly in each fire tube (*see Figure 5*) sits just behind the flame arrestor. It consists of a mixing chamber, fuel gas inlet, nozzle, and pilot assembly. The pilot flame is ignited through the use of a piezoelectric push button connected to an ignitor rod. The pilot assembly contains its own fuel source apart from the burner assembly. Air is drafted in through the flame arrestor and enters the mixing chamber, where it is combined with fuel gas to create a flammable mixture, which is then ignited using the pilot flame.

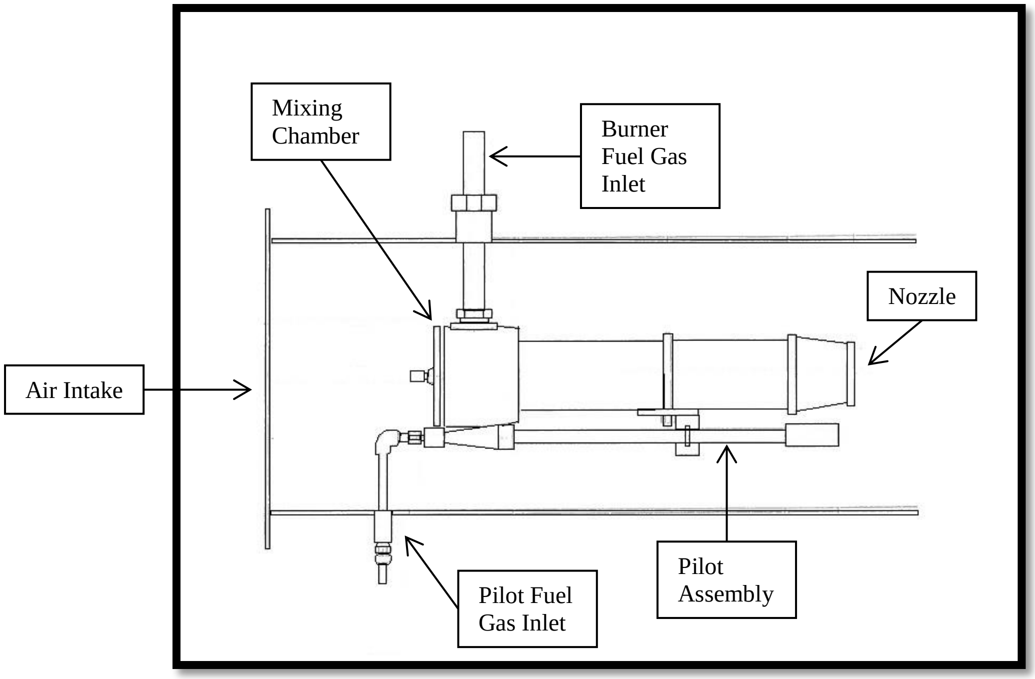

Figure 5: Representative Illustration of Burner Assembly

The exhaust gas travels through the fire tube, and upward through the associated stack. From there, it passes through another flame arrestor (often called a stack arrestor) that allows the exhaust gas to exit while preventing flames from propagating through the top of the stack. The top of the stack is further protected from weather and outside forces by a housing assembly.

Dry & Wet Oil Tanks: A dry oil[2] tank is an atmospheric tank used as a crude oil collection point prior to shipping it off of the platform via the pipeline pumps. Normally, crude oil entering a dry oil tank has been sufficiently processed and treated to reduce the amount of BS&W below prescribed levels. A wet oil tank is normally used as a collection point for crude oil that requires additional treating for excessive BS&W (*see Figure 6*).

Both tanks may be accessed through a gauge (thief) hatch, located on the top of each tank. The thief hatch serves a dual purpose: (1) to prevent the loss of vapors in the tank, and (2) to provide pressure and vacuum relief for the tank. In the event of an emergency, the thief hatch may be used to relieve pressure caused by abnormal conditions (i.e., external fire).

On this platform, both tanks are identical in size, shape, and design specifications. They are used interchangeably as dry and/or wet oil tanks due to the equalizing liquid and gas connections.

[2] Dry oil is also referred to as "clean oil."

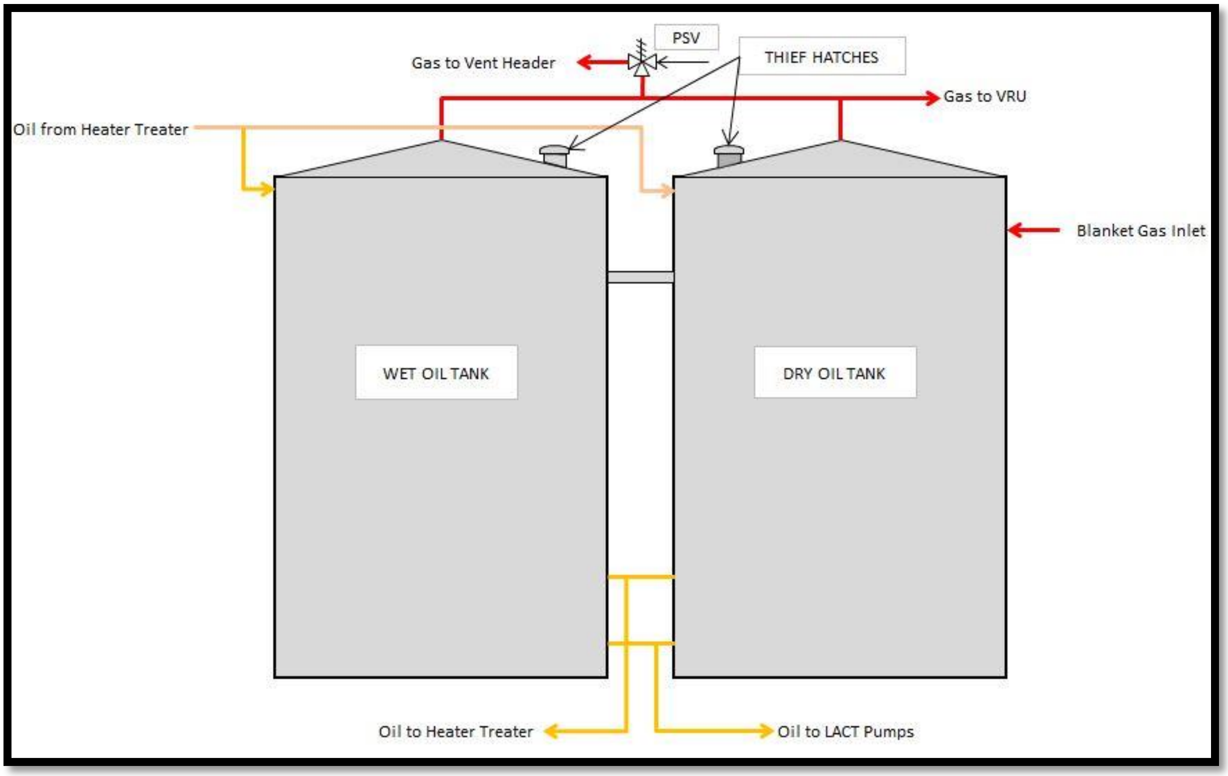

Figure 6: Representative Illustration of Dry and Wet Oil Tanks

Temperature Safety Element (TSE) Zones

The platform uses TSE fusible plugs to shut in the platform if excessive temperature exists in the vicinity of production equipment. The platform safety shutdown system logs a fusible plug failure event according to a specific zone. The zones affected by the incident (Zones 1 & 3) are depicted in Figure 7 for the main deck and cellar deck, respectively.

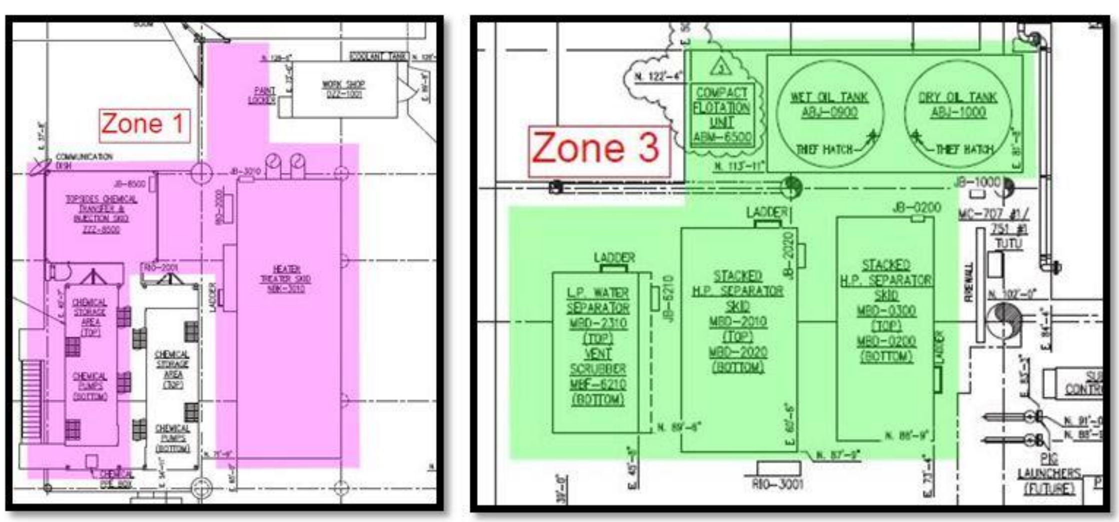

Figure 7: TSE Zone 1 (left) and TSE Zone 3 (right)

Basic Sediment & Water (BS&W) Troubleshooting

On the day of the incident, an emulsion pad formed in the heater treater on the platform due to high BS&W. Operators described that prior to this instance, the general process for troubleshooting an emulsion pad involved the following steps, in sequence: (1) shutting in the wells and relevant topside production equipment, (2) draining the emulsion pad from the heater treater into the dry oil tank, (3) batch treating the emulsion pad in the dry oil tank with a chemical demulsifier, and (4) circulating the treated emulsion back to the heater treater. At the time of the incident, LLOG did not have a written SOP outlining the steps of this process.

Sequence of Events

From April 2015 until March 2016, the GI Block 115 platform was shut in while structural and platform modifications were taking place. Included in those modifications was the purchase of the packaged, skid-mounted heater treater in April 2014 that was installed on the platform on August 6, 2015.[3] Two exhaust stacks were then installed on the heater treater on August 26, 2015; with two exhaust stack support braces added on October 30, 2015.

The following sequence of key events, reflecting activity since the platform resumed production in March 2016, was developed from a combination of documentation and witness accounts provided to the panel throughout the course of its investigation into the November 12, 2016 incident (times are approximate, in 24-hr format).

May – October 2016

Shortly after the platform came back online, excessive BS&W levels began to affect oil production at GI Block 115, believed to be attributed to MC Block 751 well. During this time period, excessive BS&W also started to affect production from the MC Block 707 well and the EW Block 878 well. Both LLOG and WOG attempted multiple chemical treatment options to address the issues.

Platform personnel continued to address BS&W issues with the MC Block 707 and MC Block 751 wells. They attempted to troubleshoot those issues by temporarily shutting in some of the wells, using chemical treatment processes (including batch treatment) and/or draining emulsion pads from the heater treater. In addition, they continued to use heat from the heater treater and retention time in an attempt to address the BS&W problems. These attempts sometimes provided brief relief from the BS&W issues, but they did not provide a permanent resolution.

Personnel indicated that the task of shutting in and treating with chemicals and/or draining the heater treater occurred frequently, sometimes daily. Personnel described chemical batch treatment methods of either pumping it into the heater treater and circulating, or manually dumping buckets of chemical into the wet or dry oil tanks.[4] They explained the process for draining the heater treater as draining it with a hose to either cuttings boxes or the dry oil tank.

[3] A picture of the skid-mounted heater treater at an onshore location prior to transportation showed the burner assembly already bolted to the heater treater vessel.

[4] One common method for batch treating described by some operators was to carry a bucket of chemical from the main deck to the cellar deck, climb the ladder to the platform between the wet and dry oil tanks, open the tank's hatch, ground the bucket and pour it inside. At least one operator indicated that they sometimes had to do this between one and four times per day. They indicated that they did not turn off the heater treater burner when opening the dry oil tank hatch and batch treating.

November 1 – 11, 2016

To provide more heat to the wells, LLOG employed a rental steam heat media system at the platform. The additional heat improved the BS&W problems and for the most part resolved their flow assurance issues. However, personnel indicated that they still occasionally drained the heater treater and/or batch treated the dry or wet oil tank to improve their BS&W, including in the days leading up to the incident.

LLOG also instituted the use of a new emulsion breaker (EB) for batch treating. The new EB was placed on a small skid on the main deck, a few feet northwest of the heater treater. One of the operators indicated that the chemical injection tubing going into the heater treater was of insufficient diameter (1/2 inch) to allow the EB to flow because of the higher viscosity of the new EB. This required operators to batch treat by draining the fluids from the heater treater to the dry and wet oil tanks via a hose and manually dumping the EB into the tanks using buckets.

A day shift operator said there was a pad in the inlet side of the heater treater on the night of November 11, 2016. He indicated that before he went off shift, he connected one end of a hose to the heater treater and threw the other end over the side of the platform where another operator got it and put it in the oil tanks through a thief hatch, where they drained between four and ten barrels from the heater treater to the dry oil tank. The same operator described that he later found out that the PIC and the night shift decided to empty the whole heater treater into the dry and wet oil tanks that night.

November 12, 2016 (Day of Incident)

General Activity and the Loss of Steam

One of the Nalco representatives stated that they were awake at about 0500, fighting high water cuts and a pad that was forming in the heater treater. He said they were looking at different scenarios and which option to choose, doing BS&W shake outs every 30 minutes to every hour beginning at about 0500 or 0600.

The PIC and some other personnel indicated that they held a morning safety meeting to discuss operations at the GI Block 115 platform. Some personnel onboard (POB) reported that they were not in attendance because they were unaware of a morning safety meeting. Although LLOG provided several job safety analyses (JSAs) to the panel for work activities for this day, none were involving batch treatment or circulating from the heater treater.

Most personnel interviewed indicated that platform operations were proceeding normally that morning. However, estimated at between 0730 and 0900, the steam unit failed which resulted in a loss of steam generation, removing heat from the produced oil. The steam technician worked to repair the unit, but while it was inoperable for about 1.5 to 2.5 hours, personnel identified that their BS&W was climbing and an emulsion pad appeared to be building in the heater treater.

High BS&W and Well Shut-in

NOTE: The injured personnel (IPs) are referred to as "IP-1," "IP-2," and "IP-3."

At approximately 1130, the PIC advised the operators on shift about a high BS&W issue, and that they were "shutting in." The Work Task Leader (WTL), IP-1, stated that he was informed of this over the radio, whereas IP-2 and IP-3 spoke with the PIC in-person. IP-2 and IP-3 indicated that they thought they would start troubleshooting the issue by draining the pad from the heater treater to the oil tanks. They did not indicate having any knowledge of a specific plan or task to add chemical or batch treat the oil tanks. Both the PIC and IP-1 indicated that they did not communicate about what specifically IP-1 would be doing.

While there was no indication provided to the panel that they performed a JSA or discussed specific job tasks, the PIC indicated that his expectation was that he would shut in the wells from the control room and then let the operators know they could start shutting down the associated process equipment on the topside, which was in accordance with LLOG's Normal Shutdown Operating Procedure. He identified the process equipment to be shut in as the heater treater, the reboiler, the compressors and the vapor recovery unit (VRU).

The PIC informed the Nalco representatives of the intent to shut in, and then the Nalco representatives went to the workshop on the north side of the platform to decide what chemical they were going to recommend to batch treat with or how much; but they had yet to give a recommendation prior to the incident.

The PIC shut in the LLOG wells at the following times: the MC Block 705 well at 1141; the MC Block 707 well at 1143; and the MC Block 751 well at 1144. WOG's operator indicated that he shut in the EW Block 878 well and had come back to the control room to get his readings when LLOG was in the process of shutting in their wells. At the time of the incident, none of the indicated topside equipment was shut in.

Operator Activities Prior to the Incident

Subsequently, with all of the topside equipment still on line, including the heater treater burner, IP-1 said he thought he could drop "a couple of inches" (about 20 gallons) of the new EB into the dry oil tank, turn on the lease automatic custody transfer (LACT) charge pump, and he could treat the dry oil tank and the heater treater "really, really fast with this chemical and maybe knock the BS&W out and come back on line." To make it even easier, rather than using buckets or routing a hose around the side of the platform, IP-1 said he intended to feed a hose through the grating from the chemical tank to the wet and dry oil tanks that were almost directly below it.

IP-1 indicated that he contacted IP-2 over the radio and told him to get on the oil tanks so he could drop him a hose. Under the impression that they would be draining the heater treater to the oil tanks, IP-2 went to the cellar deck. He then climbed up a ladder located between the wet and dry oil tanks to an access landing that was a few feet below the top of the tanks. He stood on the middle railing surrounding the access landing, where the thief hatch to the dry oil tank was at about eye-level.

IP-1 was on the main deck looking for a place in the grating wide enough to stick the hose through, and at one point was kneeling down. He was only a short distance above IP-2, and both said they could see and talk to each other easily through the grating. IP-1 was located between the chemical tank and the heater treater, only a few feet from each and almost directly over the dry oil tank.

Without an opening large enough for the hose to fit through, IP-1 grabbed a crowbar from the workshop, where the Nalco representatives were working, to pry the grating apart so the intended hose would fit. While prying, he broke a stem of the grating – which he described as occurring before the hatch was opened. IP-1 and IP-2 both indicated that IP-1 never attempted to put the hose end through the grating, but IP-1 said he thought the hole was big enough once the grating broke. IP-1 had not yet told IP-2 that the hose he was going to feed him was for a chemical, which he said he would have done once they bled the blanket gas pressure off the dry oil tank, and once he got the hose through the grating.

IP-2 unlatched the hatch and slowly let it open up as the pressure came off – until he felt comfortable with the pressure – and then let it open up all the way. He explained that he told IP-1 that there was more pressure on it than when he had opened the hatch in the past. IP-1 said it was going to have a little more,[5] so to just open it slowly. Once opened, IP-2 said the hatch stayed open on its own, but he stayed standing on the rail to catch the hose when IP-1 lowered it through the grating. He said his left arm was on the wet oil tank on the left, and his right arm was right by the hatch.

At about 1200 or 1205, IP-3 walked up to IP-1 on the main deck, and they engaged in a brief conversation about what they were doing. IP-1 believed that while talking to IP-3, he was squatting down near the hole in the grating he had made (represented by Δ in Figure 8), between the chemical tank and the heater treater, with his forearms on his knees and his palms faced down (wearing rubber chemical gloves). Facing each other, IP-3 had the heater treater to his left and IP-1 had it to his right (each represented by yellow circles in Figure 8).

[5] The shutdown valve (SDV) for incoming blanket gas, which is natural gas supplied from the fuel gas system, to the wet and dry oil tanks remained open until the incident.

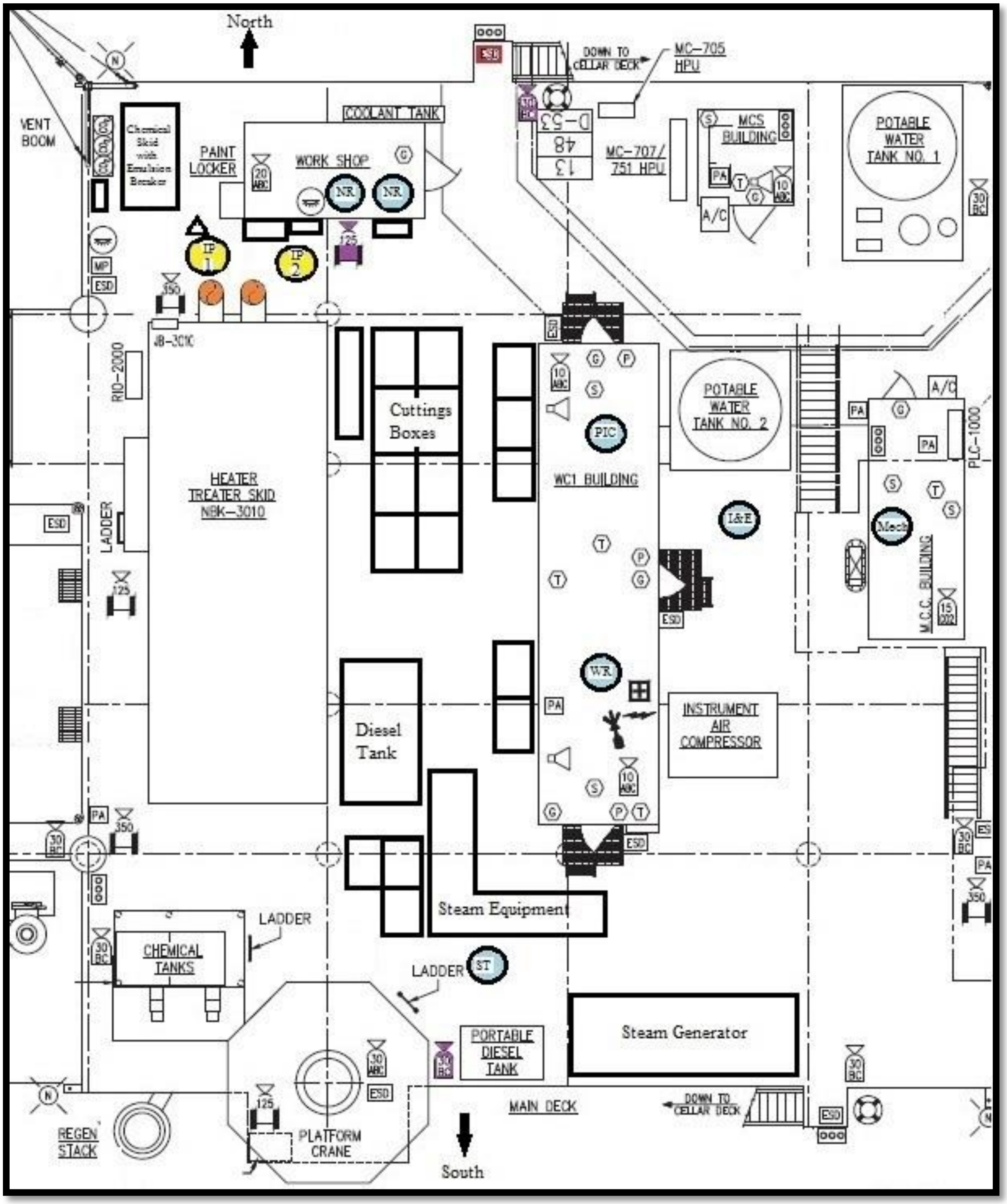

Figure 8: Approximate Personnel / Equipment Locations at the Time of the Incident

The Incident

At approximately 1206, IP-1 said he looked up at IP-3 and he got a stronger smell of gas than he expected, and both of their eyes got big. IP-1 said he was going to look down and tell IP-2 to close the tank, when he heard the heater treater burners (represented with orange in Figure 8) going full blast and catching another gear as the gas from the dry oil tank came through. IP-1 then heard a 'whoom-whoom' (like lighting charcoal fluid) and he saw a fire come from the heater treater burners and surround him. He described the flame as red and orange, followed by a little white flash like a strike of lightening or something. He then took off running south around the west side of the heater treater. He said that when he got in front of the Remote Input/Output (RIO)-2000 panel, still in the fire, he could feel the heat in his nostrils. He stated that he kept running south and away from the fire, exiting the flame in the vicinity of the heater treater access platform. He then continued south to distance himself from the flame.

IP-3 described hearing a flash that sounded like the igniting of the gas from a barbeque grill, and that he was looking at IP-1 when he heard it. He explained that he saw the flames come from the heater treater from a height a little bit lower than his face (corresponding with the height of the heater treater burners) and then crossed straight in front of him as it kind of rolled to the chemical tank on his right; between where he and IP-1 were located.

IP-2 estimated that the fire ignited within about 25 to 45 seconds after opening the hatch. He described it as a whoosh that felt like it was all around him for a split second, but he did not know where it came from. He said he knew the fire's fuel was coming from the tank, so he quickly shut the hatch and then jumped down off the approximately 15 foot tank by hanging from the inside of the squirrel cage on the ladder and then dropping to the cellar deck from there. IP-2 said he looked back at the tank and could see a small yellow flame or a small ball of flames right on the hatch, which looked like it was already starting to burn out. He said it didn't seem as big as it felt when he was on the tank.

When the fire started, IP-3 explained that he started backing up and then fell over; not because of any pressure wave from the fire, but because he was backing up. When he fell, his glasses flew off and then his hard hat hit the grating. He got up, got his hard hat and went to and pushed the emergency shut down (ESD) at the station at the top of the north staircase (outlined with red in Figure 8), while also using his radio to yell, "fire, fire." IP-3 thought someone else might have already pushed the fire alarm because the alarm had already started to go off.

The Nalco representatives did not see the fire or hear any alarms from inside the workshop (represented by a blue circle with "NR" in Figure 8)[6], but a couple of minutes after IP-1 grabbed the crowbar from the workshop, they saw IP-3 run past a window in the workshop toward the ESD. One of them exited the workshop and heard IP-3 yell 'fire.' When he looked at the heater treater, he saw flames as high as the two yellow support beams on the sides of the heater treater, estimated at 20 to 30 feet; but he did not notice any smoke. He went back into the workshop to get his coworker, and by that time, he stated, "it started going down, but it was still coming out pretty good at about six feet." They said the PIC and other operators had grabbed the extinguishers and were fighting the fire, so they moved to the south side of the platform.

[6] They indicated that the Gaitronics speaker had not been working.

The steam technician was standing by the steam unit on the south end of the heater treater (represented by a blue circle with "ST" in Figure 8). He described hearing a boom from a loud explosion, feeling a pressure wave that shifted the platform and seeing a big, reddish-orange fire ball extend up around and above (but not out of) the heater treater's stacks, with black smoke.

Figure 9 depicts the alarm summary provided to the investigation panel covering the time of the incident on November 12, 2016. The Heater Treater Burner Low Flame #1 and #2 alarms equate to the Burner Safety Low (BSL) safety devices required by API RP 14C for fired vessels. Pursuant to API RP 14C, the BSL provides primary protection from excess combustible vapors in the firing chamber caused by a mechanical failure of the fuel control equipment. The sensor should detect a flame insufficient to ignite the entering vapors and shut off the fuel. On this heater treater, the BSL alarms required two conditions to activate (trip): (1) the pilot burner flame must be out, and (2) fuel gas is being supplied to the burner assembly. Upon activation, the BSL shuts down all incoming fuel gas and blanket gas sources to the heater treater. The shutdown valve (SDV) log provided to the investigation panel indicated that the fuel gas and blanket gas SDVs closed at 12:07 pm that day.

The alarm history also shows that TSEs in Zones 1 and 3 tripped 10 seconds apart at about 12:07 pm. The investigation panel was informed that two of the four TSEs located in Zone 1 (near the flame arrestors), and one TSE in Zone 3 (near the dry oil tank thief hatch) were melted. The PIC stated that the melted elements were discarded and replaced to maintain the integrity of the TSE fusible plug loop.

TIME	ALARM
12:06:52	HEATER TREATER BURNER LOW FLAME #2 TRIP
12:06:54	HEATER TREATER BURNER LOW FLAME #1 TRIP
12:06:56	EW-878 #3 FA1 ALARM TRIP
12:06:56	EW-878 #3 HPU CONTROLLED ESD/TSE ALARM TRIP
12:06:56	TSE ZONE 1 MAIN DECK LL TRIP
12:06:56	WALTER OG EW878 PROCESS S/D TRIP
12:06:56	WALTER OG EW878 EMERGENCY S/D TRIP
12:06:56	STEAM GENERATOR PROCESS S/D TRIP
12:07:01	ESD CIRCUIT PRESSURE LL TRIP
12:07:06	TSE ZONE 3 CELLAR DECK WEST LL TRIP
12:07:14	EAW-6420 NATURAL DRAFT BURNER LOW TRIP

Figure 9: Alarm Summary for November 12, 2016

Post-Incident Response

IP-3 said he grabbed the 30 pound fire extinguisher that was hanging on the railing near the ESD (highlighted with purple on the north side of the platform in Figure 8) and went back to the site of the fire. IP-3 estimated that at this time, the fire was easily over seven feet high, at least above the RIO-2000 panel and consuming the entire area. He said he couldn't tell what was actually on fire at all - it was just a wall of fire there. He described using the extinguisher until it ran out, then the PIC and IP-1 (after circling the entire way around the heater treater) used a wheeled 125 lb. fire extinguisher unit (highlighted with purple on the south side of the work shop in Figure 8) to put out flames coming up from below the main deck. IP-3 said he did not notice any smoke from the fire.

The Instrumentation & Electronics (I&E) Technician (represented by a blue circle with "I&E" in Figure 8) was not aware of the batch work that they were going to do or that operators were going to shut in the platform. He was walking around the platform when he heard a 'whoosh' noise and he took a few steps to look around a corner toward the heater treater to see a red flame flash upward toward the heater treater and then back down away from it. He then ran toward the heater treater but they already had a couple of operators there trying to put out what was left of the fire. He thought he remembered a little bit of flame at the hatch of the dry oil tank, but it was mostly out. He said he ran around to use a wheel unit on the southwest corner of the heater treater, but the wind was blowing the "Purple K" [fire suppressant] and was suffocating him, so he went into the control room.

The steam technician ran to the control room (identified as the "WC1 Building" in Figure 8) to notify the PIC and others, but he thought they were already coming out and the fire alarm was already going off. He grabbed a fire extinguisher from the handrail above the crane pedestal (highlighted with purple on the south side of the platform in Figure 8) and started helping a few other guys fight the fire, which was about half the height it had been when he first saw it. He said he did not get a good view of it due to the extinguisher smoke, but it looked like the fire was coming up to the main deck through the grating.

The PIC (represented by a blue circle with "PIC" in Figure 8) said he first learned about the fire when somebody opened the door to the control room and screamed "fire." He said he got up, ran out the door, and then he heard the fire alarm activate. When he got within sight of the incident location, he said all he saw was smoke or white dust from the fire extinguisher. He said the fire was already extinguished. He said he then "grabbed that 125 fire extinguisher and sprayed everything once again," but he did not see a flame or a fire – just melting plastic.

The WOG operator (represented by a blue circle with "WR" in Figure 8) said that after hearing someone yell 'fire,' he walked out of the control room toward the west side of the platform and saw orange flames extending just barely over the heater treater; and black smoke that seemed to be coming from the plastic that burned on the panel. There was a wheeled fire extinguisher engulfed in fire at the north end of the heater treater where the fire was, so he went around the other side of the control room to help, but by that time the fire was out. He then sprayed the beam in front of the heater treater where the fire seemed to come from with a water hose after they had it out, just to make sure everything cooled down.

The platform mechanic (represented by a blue circle with "Mech" in Figure 8), had not been told that the operators were shutting in the platform or that that they were going to drain the oil pad out of the heater treater; nor had he been told to shut anything down himself. He was in the nearby Motor Control Center (MCC) building when the incident occurred, and exited the building when he saw on his HMI screen that a compressor had shut down. Upon exiting, he saw powder from the dry chemical extinguishers. Operators had already put out most of the fire, but he assisted to extinguish a small flame coming from below the grating.

IP-2 ran up to the main deck and the first person he saw was IP-1. He then saw the I&E Technician, who had a fire extinguisher. He also saw a light gray smoke or extinguisher blast. But by the time IP-2 got up to the main deck he never even saw a flame up there. IP-2 said they had it burned off or they had it put out by the time he got up there. Personnel estimated the fire lasted anywhere from a few seconds to a few minutes.

IP-1, IP-2, and IP-3 then went to the control room where the mechanic and some of the operators assisted them with first aid treatment. The PIC quickly called for a helicopter. Personnel indicated that they heard alarms go off, but they did not muster after the incident, which the PIC said was because everybody was right there, and it was over.

LLOG reported that by approximately 1210, the PIC contacted LLOG's Operations Manager, advising him of the situation and requesting a helicopter flight for the injured personnel. After calling for the evacuation of the IPs, the PIC said they just kept dealing with the injured operators until the helicopter got there. Once the IPs were off the platform, the PIC said that the rest of the operators "went and assessed and make [sic] sure everything was down, killed everything and blocked everything in, just to make sure nothing could get back to it." The PIC moved the fire extinguisher hose for safety and later disconnected power to the RIO-2000. They indicated that they did not make repairs at that time except to replace the damaged TSEs, for which BSEE had given permission, in order to get the safety systems back up.

LLOG notified the BSEE New Orleans District immediately following the incident. BSEE investigators conducted an initial site visit to the platform on November 14, 2016. After the panel was formed, a preservation notice was issued and the incident area was cordoned off. The panel members conducted an additional site visit to the platform on November 18, 2016, followed by additional visits to perform investigative activities as needed.

The BSEE Investigation

Investigation and Process

The purpose and scope of the investigation was to identify the cause(s) of the operational incident which resulted in multiple injuries and to make recommendations from the investigative findings to reduce the likelihood of a recurrence or similar incident. The panel identified what it believes to be the direct and indirect causes of the incident, as well as causal factors which may have contributed to the totality of the incident.

The BSEE investigation process included notifying LLOG and its contractors to take all steps necessary to immediately identify, retain, and preserve all potentially relevant information related to the incident. The BSEE panel conducted multiple site visits, numerous witness interviews and requested and reviewed large volumes of documentary materials. The documentation provided by LLOG and its contractors included, but was not limited to, safety and environmental management systems, safe work practices, policies, procedures, equipment design and maintenance records, training records, and communications. This section of the report represents key focus areas and relevant findings identified during the investigation.

External Fire

Fires start when a combustible material (fuel), in combination with a sufficient quantity of an oxidizer (oxygen), is exposed to heat, and is able to sustain a rate of rapid oxidation (chain reaction). These four items – fuel, oxygen, heat, and a chain reaction – are commonly referred to as the "fire tetrahedron" (*see Figure 10*). All of these items are necessary for the existence of fire. For this report, the investigation panel focused on identifying the sources and causes of fuel and heat.

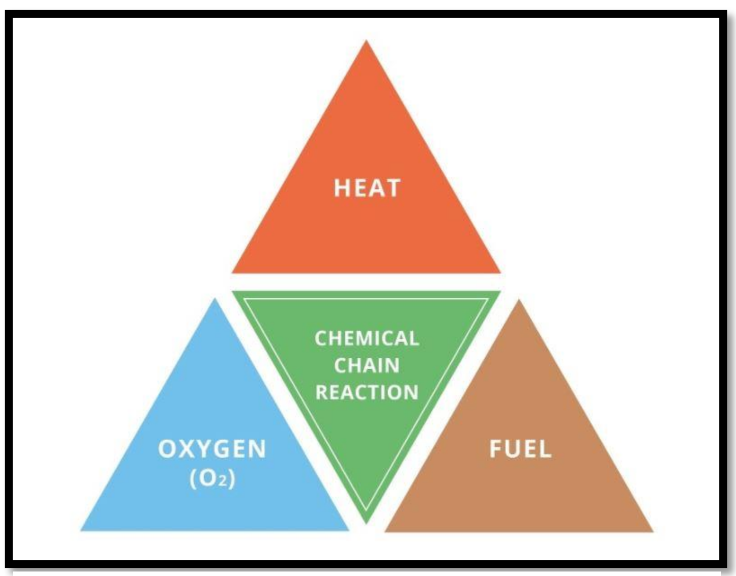

Figure 10: Fire Tetrahedron

Fuel

In this case, the fuel source originated from, and was continuously fed by, an open thief hatch on the dry oil tank, located on the cellar deck. When IP-2 opened the hatch, a cloud of natural gas dispersed into the atmosphere. The gas was a mixture of flash gas[7] from the crude oil in the tank and blanket gas,[8] provided by the platform's fuel gas scrubber. Blanket gas pressure is maintained by a regulating valve on the blanket gas inlet line set at 3 inches water column. However, when IP-2 opened the hatch, the regulator, sensing a pressure decrease, should have fully opened. This would have allowed more blanket gas into the tanks, providing a greater volume of gas to be released into the atmosphere. After the fire began, IP-2 attempted to secure the fuel source by closing the thief hatch.

Wood Group calculated and provided a dispersion model of the estimated gas cloud at the time of the incident (*see Figure 11*), based on an estimated wind speed of 9 mph and a specific gravity of 1.5, which is a conservative estimate based on the provided gas specific gravity at the VRU (1.2074). The dispersion model was produced using an estimated tank gage pressure of 0.7 pounds per square inch (psig).

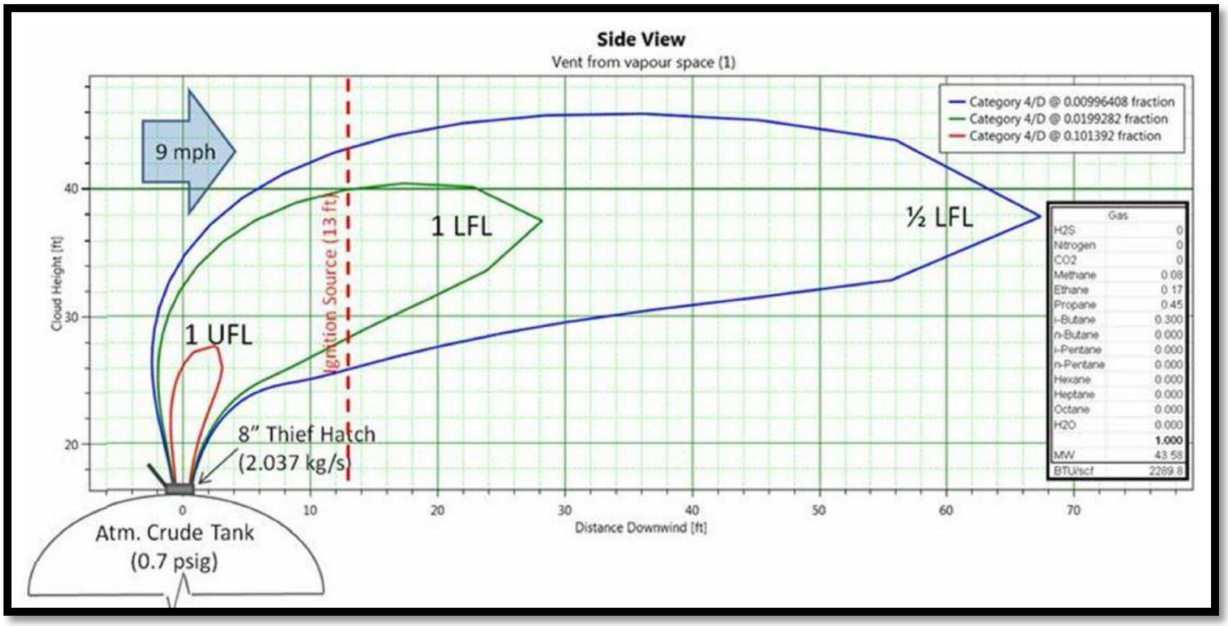

Figure 11: Gas Dispersion Model provided by Wood Group

Within the model, both the Upper Flammable Limit (UFL) and Lower Flammable Limit (LFL) are depicted. These limits are the maximum and minimum concentrations, respectively, of a combustible gas necessary to support its combustion in air. The presence of sufficient heat within the envelope of UFL and LFL equal to or greater than the flash point of the gas mixture would ignite the gas mixture. Using a 1:1 scale overlay of the Wood Group dispersion model and approximate wind conditions, Figures 12 and 13 depict the panel's estimate of the flammable envelope in relation to the platform and the related equipment.

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[7] Flash gas refers to the spontaneous vapor produced due to depressurization and/or heating of crude oil during processing.
[8] Blanket gas refers to the natural gas that is supplied to tanks/vessels in order to prevent tank/vessel collapse and oxygen intrusion.

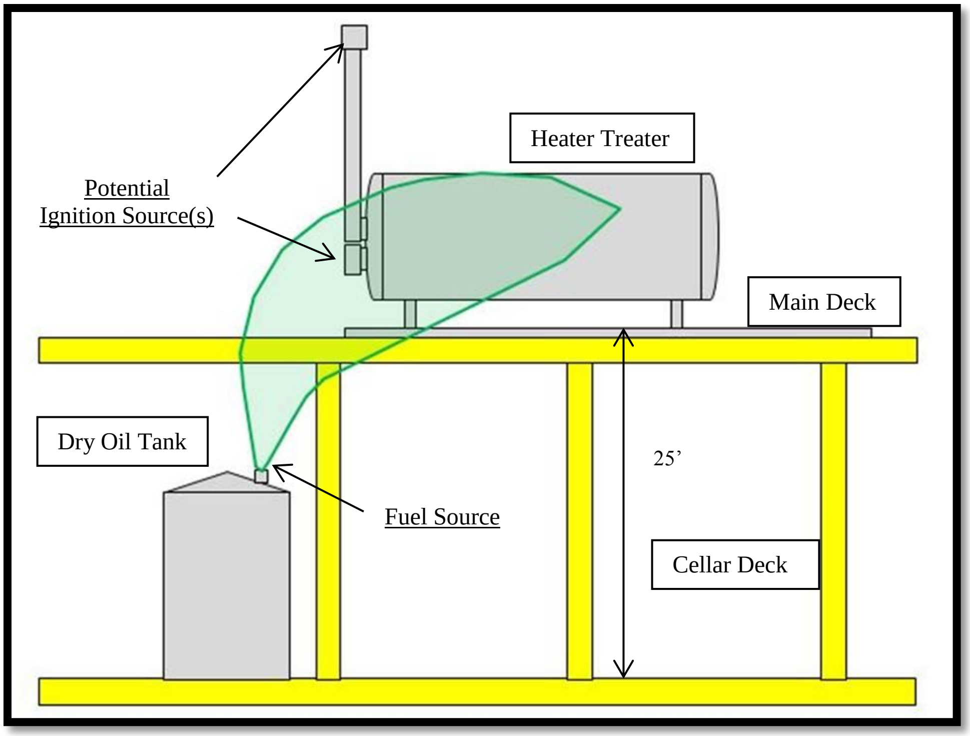

Figure 12: Side View of Estimated Flammable Gas Mixture

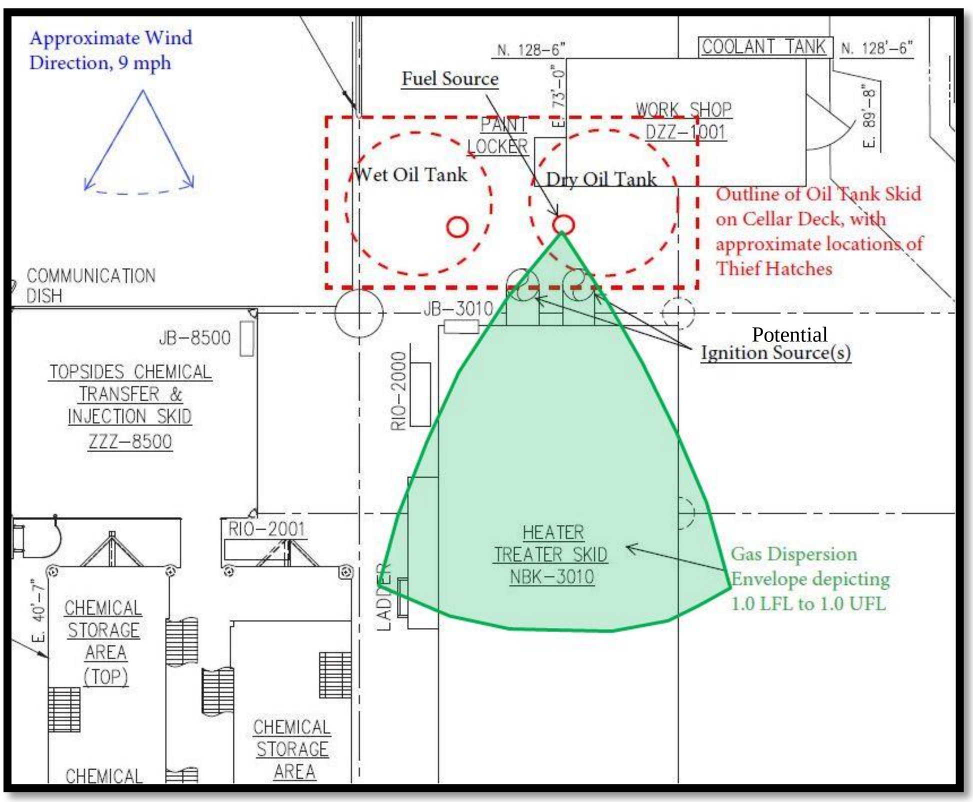

Figure 13: Top View of Estimated Flammable Gas Mixture

Heat (Ignition)

In analyzing potential ignition sources, it was necessary for the panel to consider the autoignition temperature (AIT) of the gas. The AIT is the lowest temperature at which a flammable substance can spontaneously ignite in a normal atmosphere, absent an external ignition source, such as a flame or spark.

In obtaining the AIT estimate,[9] the panel used Ryng's correlation to estimate the AIT of a gas sample taken downstream of the VRU on October 26, 2016. Based on the correlation, the estimated AIT of the gas mixture on the day of the incident was 939 degrees Fahrenheit.

The panel initially considered the following as possible ignition sources, among others:

1. *Exposed hot surface, other than the heater treater*
2. *Smoking*
3. *Spark caused from metal-to-metal contact*
4. *Static electricity / arcing*
5. *Excessive stack temperature (left or right)*
6. *Hot spark emission from stack (left or right)*
7. *Flame propagation outside of air intake/fire tube (left or right)*

Following site visits to the platform, the panel did not identify any exposed hot surfaces, apart from the heater treater and its related components, in the vicinity of the incident location (<u>#1 eliminated</u>). The panel received no indication that anyone was smoking in the vicinity of the incident area. The designated smoking area was also 60 feet away, so it was not likely that anyone would be smoking near the incident area (<u>#2 eliminated</u>).

Another key finding from interviews was that a crowbar may have been used in the performance of the task. One of the personnel interviewed stated that during post-incident conversations, some people thought that the "crowbar could have sparked [the fire]." IP-1 stated that he used a crowbar to pry open a gap in the main deck grating to route a hose down to the dry oil tank thief hatch on cellar deck (*see Figure 14*). However, he also stated that this action occurred well before the fire started. Furthermore, while multiple personnel witnessed the fire at one stage or another, only two personnel witnessed the onset of external flame propagation. Both personnel stated that the flame originated from the area around the

[9] William Harper, P.E, a Petroleum Engineer with BSEE, determined the methodology and completed the calculations for the panel's AIT estimate. Although not officially assigned to the panel, Mr. Harper's expertise in this area was necessary for a thorough analysis.

heater treater flame arrestors, which would eliminate the possibility of ignition due to metal-to-metal contact from the crowbar usage.

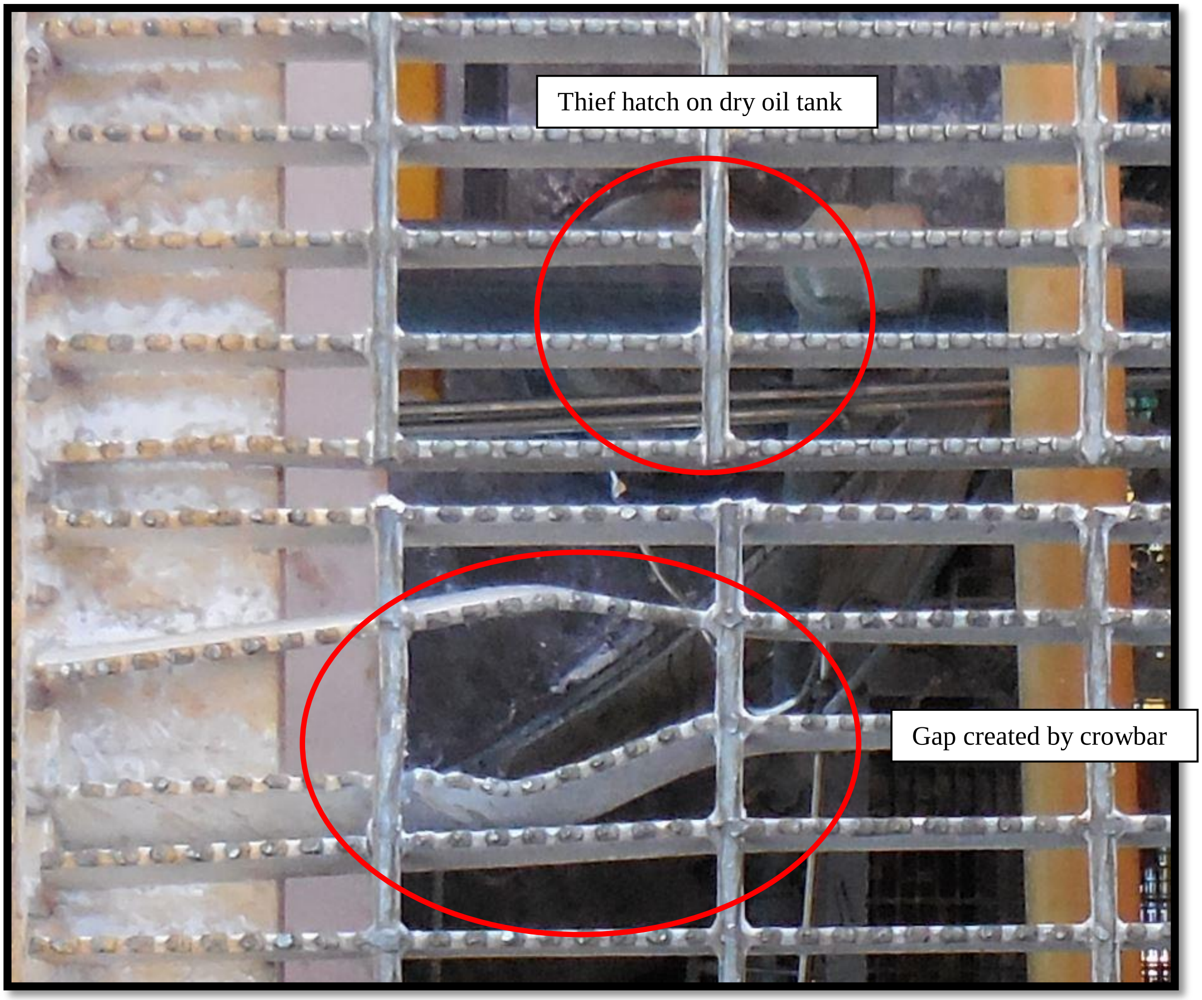

Figure 14: Gap in Grating Near Heater Treater

Another possibility for metal-to-metal contact was between a TSE and a thief hatch on top of the dry oil tank (*see Figure 15*), which LLOG identified as the most likely ignition source in their initial incident report. However, IP-2, stated that the thief hatch was open at the time of ignition. In that position, the hatch would not have been in contact with the TSE. This eliminates the possibility of metal-to-metal contact between the TSE and the thief hatch (#3 eliminated).

Figure 15: TSE Near Dry Oil Tank Thief Hatch

Of the personnel involved with the task, no one stated they were using any potentially charged equipment (i.e., bucket for batch treating, cellular phone, camera). At least one operator had been using a hand-held radio, but the radios in use at the platform were reported as being intrinsically safe. Although there was evidence of smoke, fire and heat damage to the RIO-2000 panel, wire bundle insulation, and polyflow connections (*see Figure 16*),[10] a visual inspection of areas where arcing would likely occur (RIO panel, burner control panel, heater treater control panel, wire bundles) revealed no indications of arcing damage. Static electricity can occur in most conditions; however, the panel found no evidence supporting static electricity as an ignition source (#4 eliminated).

[10] BSEE Investigators also noted heat damage to the eyewash station on the northwest corner of the main deck.

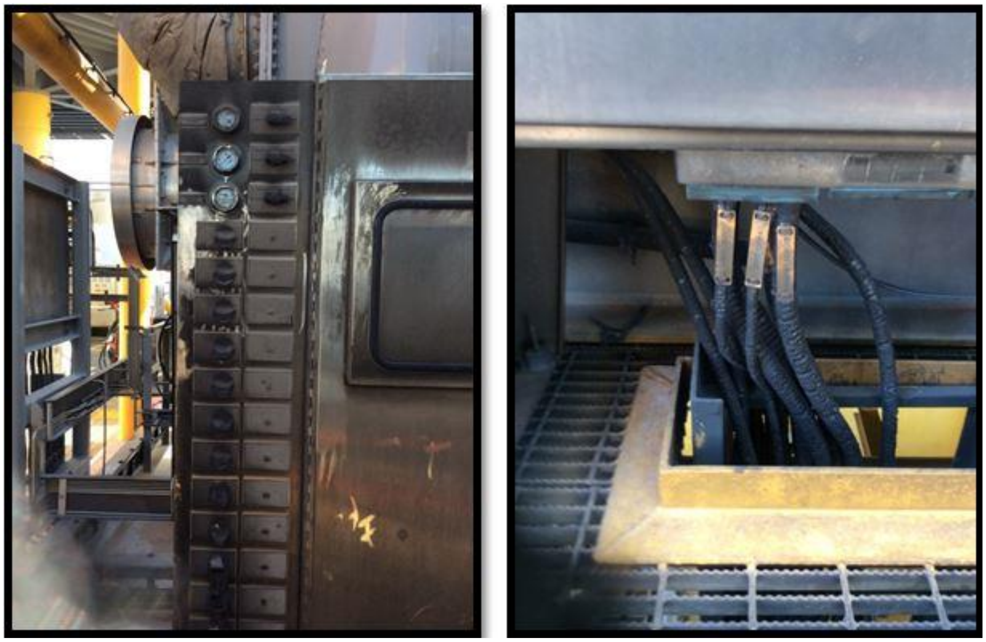

Figure 16: RIO-2000 Panel (left) and Wire Bundles (right)

Excessive Stack Temperature / Hot Spark Emission From Stack

During the initial panel site visit to the platform on November 18, 2016, the panel members discovered damage to the right stack arrestor housing (*see Figure 17*). The external damage to the right stack arrestor housing prompted the panel to request an inspection of the flame arrestors and spark arrestors.

Figure 17: Comparison of Left and Right Stack Arrestor Assemblies

The panel members also discovered exposed surfaces on the right stack due to insulation damage (*see Figure 18*). Spot 2 in Figure 18 shows possible heat damage to the insulation on the right stack, indicated by the appearance of charring.

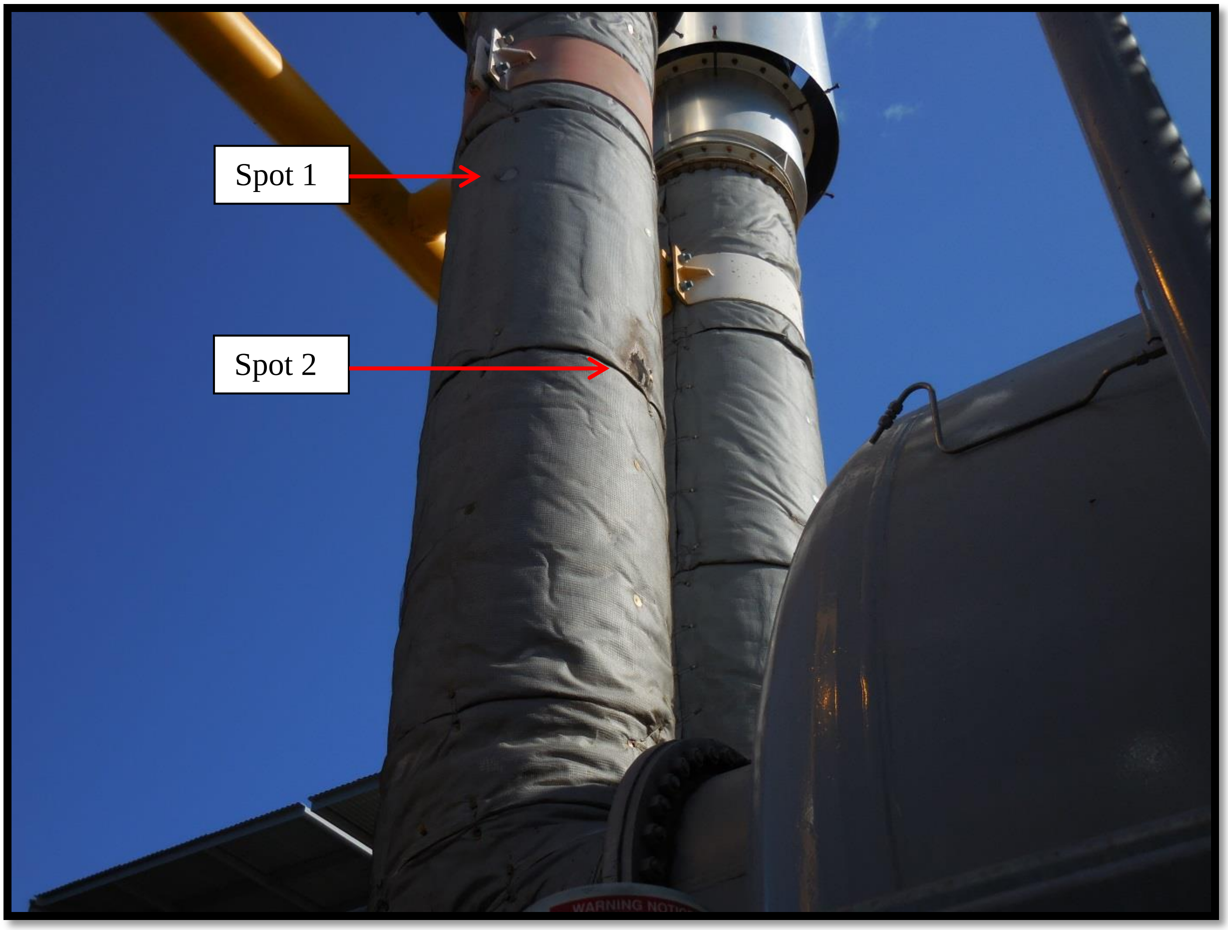

Figure 18: Heater Treater Stacks

While conducting another site visit on November 22, 2016, panel members discovered further damage to the right stack arrestor housing (*see Figure 19*). The observed damage included an abnormal dome shape to the support braces on the top of the stack arrestor housing, deformation of the weather cap and indication that the entire housing assembly had deviated from its originally installed position. An LLOG employee stated that this may have been caused by a "pressure event" that occurred at some point prior to the incident, possibly in August 2016 but maybe as early as April or May 2016.

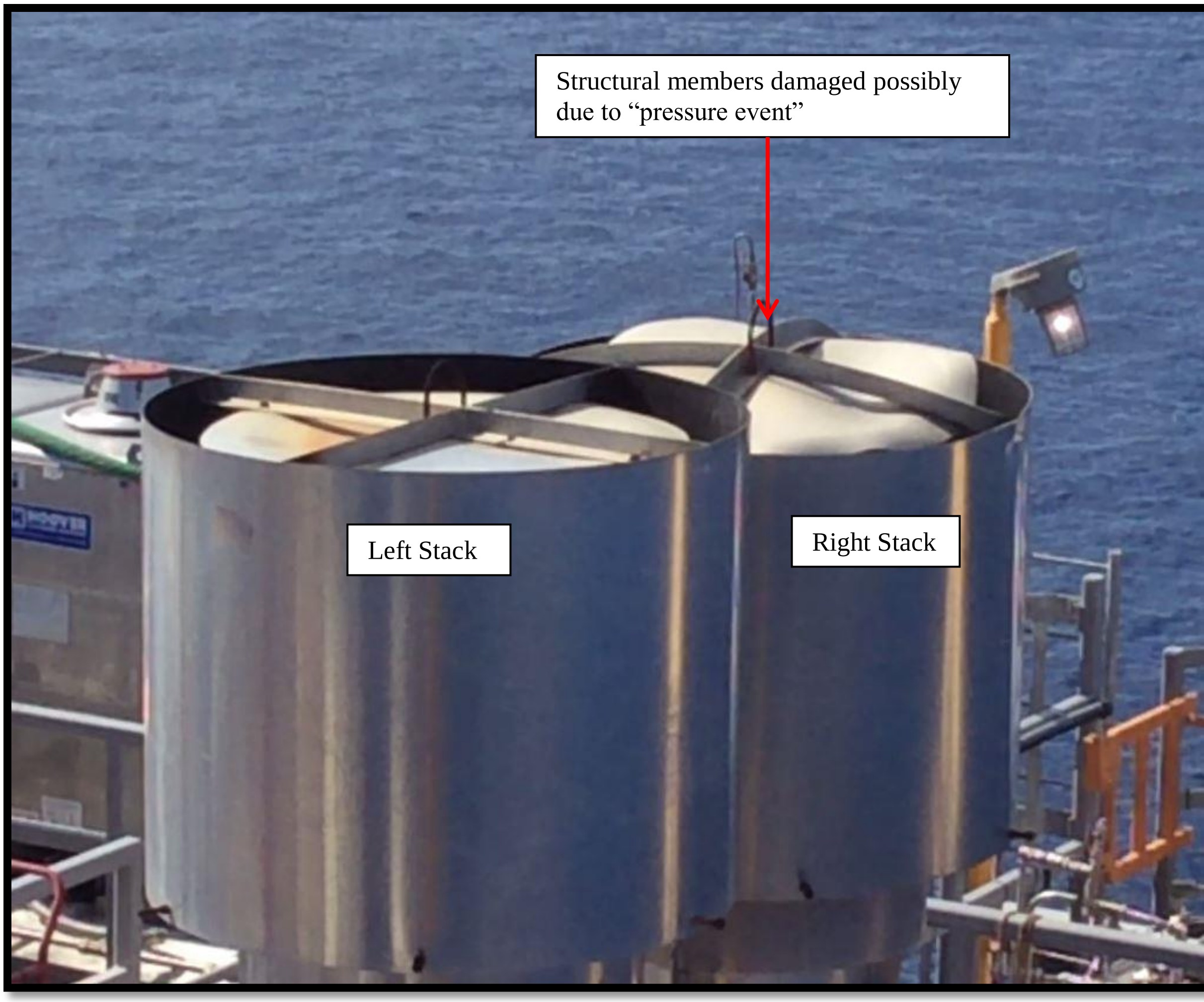

Figure 19: Stack Arrestor Housings

Flame Arresting Safety Devices

A flame arrestor is a corrugated aluminum safety device which allows air to flow through a convoluted path, but stifles fire by cooling the air below the AIT. The corrugated pattern of the aluminum sheets that make up the arrestor prevents flames from passing through. At this platform, the flame arrestors are on the inlet air side of the heater treater. The flame arrestors are in place to prevent back flow of flames from the initial ignition of the gas at the burner to the external atmosphere. The flame arrestors are the first step in the natural draft feed of air into the heater treater for combustion with the gas feed at the burner.

A stack arrestor is like a flame arrestor in its construction, but is different in its placement. The stack (or spark) arrestor is placed in the upper portion of the exhaust stack to prevent any flame or embers from igniting an explosive atmosphere. The flame arresting technology is identical to the inlet flame arrestor in that it provides a convoluted path to exit through a corrugated aluminum sheet.

LLOG provided the OEM operating and maintenance instructions for the flame arrestor, stack arrestor, and burner assemblies. In addition to the instructions provided, the OEM instructs users to refer to API RP 12N for operation, maintenance, and testing of firebox flame arrestors. The OEM lists the elements of an "operation inspection," though they do not specify when the inspection should be performed. They specify the following relevant items when performing an operations inspection:

1. Inspect surrounding area for any gas odor, mist or audible leaks and check for any unusual performance of the equipment. (The use of a combustible gas indicator is recommended.)
2. Inspect for any warping on the flanges or housing.
3. Check to see that all fasteners are in place and securely fastened. The unit must be air tight.

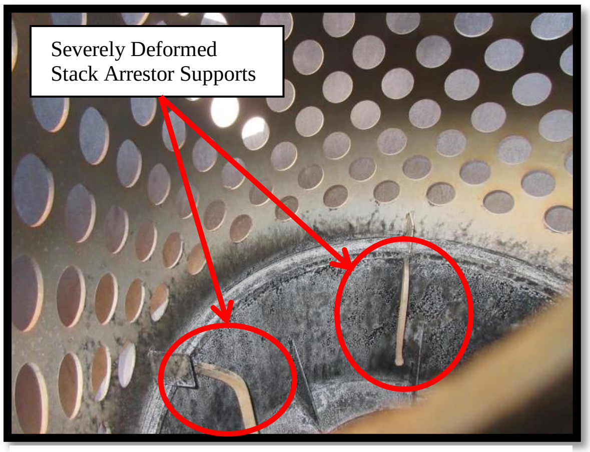

Figure 20: Right Stack Arrestor Housing

The OEM prescribed maintenance procedures for the flame and stack arrestors state that the flame cell should be removed and inspected for clear air passages semi-annually. This procedure specifies that the flame cell must be free of any nicks or notches in the outer most wraps, and must not allow any air to pass around the outside the diameter of the flame cell. It further states that the seal between the firebox flame arrestor and the fire tube must be air tight. The panel received no indication that any flame or stack arrestor maintenance or operation inspections had been completed since LLOG resumed production in March 2016.

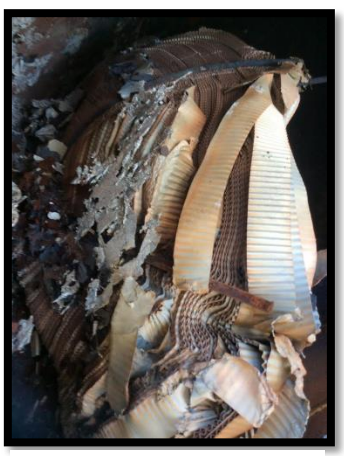
Figure 21: Right Stack Arrestor

During an inspection of the stack arrestors on December 12, 2016, the panel identified deformation of the right stack arrestor[11] supports and discovered that the stack arrestor was missing from the right exhaust stack (*see Figure 20*). There was visible damage to the right stack weather cap, which also serves as the stack arrestor housing. The left stack arrestor housing appeared to be undamaged. The damage to the right stack arrestor prompted the panel to request a third-party inspection of the fire tubes.

On January 9, 2017, the panel observed a third-party inspection of both fire tubes and stacks. During this inspection, the panel discovered the right stack arrestor sitting at the bottom of the stack, with significant damage

[11] For the purposes of the report, the EAW-3020 natural draft burner and its components are referred to as "left," and the EAW-3021 natural draft burner and its components are referred to as "right."

(*see Figure 21*). The left exhaust stack did have a spark arrestor intact, but there was significant heat damage to both the arrestor and the arrestor housing (*see Figure 22*). The initial survey of the damage by a BSEE engineer[12] suggests that the heater treater was exhausting at a temperature approaching or above the melting point of the aluminum that made up the housing and the arrestor. The arrestor manufacturer indicated that the stack arrestor and supports were made of the same aluminum alloy series, for which the onset of thermal deformation begins at approximately 700 degrees Fahrenheit. The published melting point of the aluminum alloy series is 1170 – 1210 degrees Fahrenheit. Both fire tubes appeared to be undamaged, with minimal deflection due to deformation.

Figure 22: Existing Spark Arrestor (left), Compared to New Spark Arrestor (right)

Temperature Safety Switch – High (TSH) Sensors

Each stack was equipped with a TSH in accordance with API RP 14C (*see Figure 23*). The models in use were Exline sensors that are directly installed (i.e., without the use of a thermowell). The switches were connected to a pneumatic control system via tubing and fittings. At a predetermined temperature, the eutectic solder will melt, creating a pressure drop in the pneumatic control system. This pressure drop would result in the heater treater shutting in. The predetermined temperature for these TSH devices was 1170 degrees Fahrenheit.

[12] Dr. Candi Hudson, a Materials Engineer with BSEE, made the assessment based on information provided by the panel. Although not officially assigned to the panel, Dr. Hudson's expertise in this area was necessary for a thorough analysis.

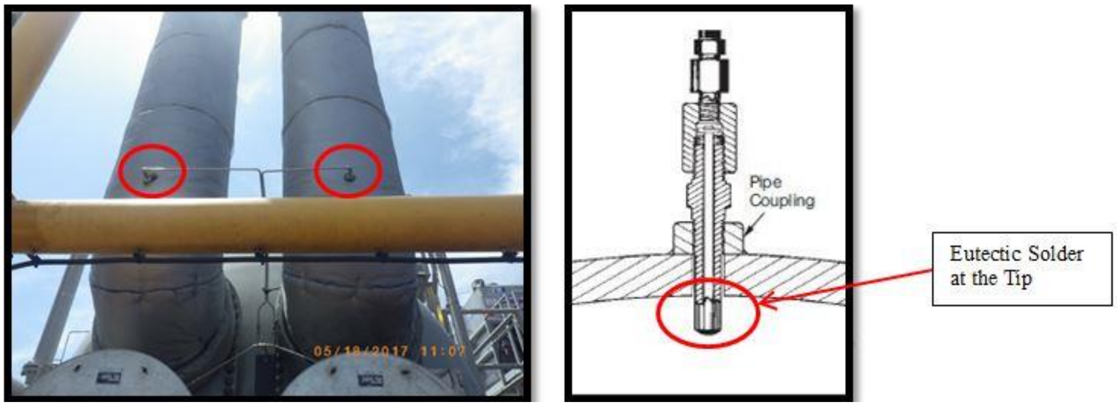

Figure 23: TSH Locations and Schematic

Activation of either TSH-3020 or TSH-3021, which are the tag numbers for the heater treater stack TSH devices, shuts in several production components, including the heater treater and burner assembly. LLOG was unable to provide information for the panel to evaluate if a TSH activation occurred since the platform resumed production in March 2016.

The panel received operator records in May 2017 and noticed a particular log entry from the provided GI Block 115 Operator Turnover Log. The log entry indicated that the TSH elements were inspected on November 21, 2016, and it stated that "the one on the right [TSH-3021] was scared [sic] up looks like it got hot, one on the left normal wear."

Fire Tube Flange Gap

The manufacturer's Operating and Maintenance Instructions stressed the importance of ensuring no air paths existed between the flame arrestor and fire tube. Special emphasis was placed on performing an inspection of all seals and seams, the seal between the flame arrestor and the fire tube must be air tight, and any seam on the fire tube must be free of cracks or holes which might allow a flame to escape. In addition, both the flame and stack arrestors should be removed and inspected for clear air passages on a semi-annual basis. This included inspection and cleaning of the arrestor body, and all gaskets should be inspected for cracks, breaks and excessive wear. The panel did not receive indication that this equipment had undergone an inspection such as this between when they resumed production in March 2016 and the time of the incident.

During the December 12, 2016 flame arrestor inspection, the flame arrestors appeared normal, showing no damage upon inspection. There is no evidence to suggest a failure of either of the flame arrestors. However there was a noticeable gap in the mating flange that connected the left flame arrestor assembly to the heater treater.

The gap was measured by a third-party fire investigator at approximately 4 inches in length and opened approximately 1/4 inch at the greatest opening, with daylight visible through the gap after removal of the flame arrestor. It was noted that a minimum gap of 1/16 of an inch in the gasket or within the flame arrestor could create a flame path.

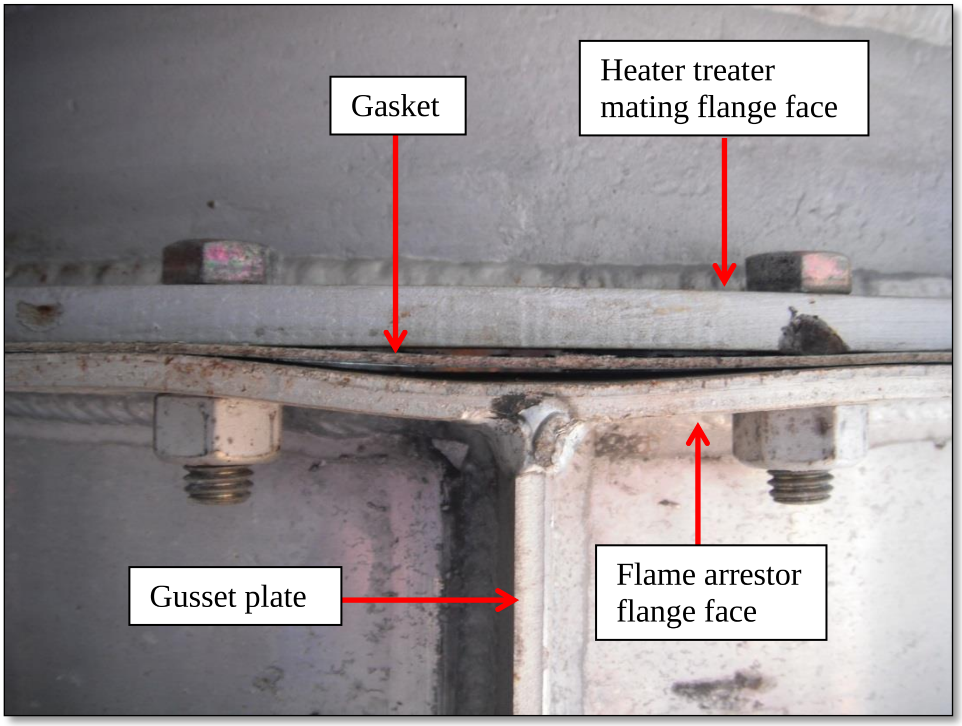

Figure 24: Gap in Heater Treater Fire Tube Flange

Figure 24 shows the mating flange connecting the left flame arrestor to the heater treater, viewed looking up from beneath the vessel. The flange face on the side of the heater treater is flat, whereas the flange face on the side of the flame arrestor is bowed between two adjacent bolts. The point where the gap is largest corresponds roughly to the point where a gusset plate is welded to the flame arrestor flange face.

The function of a gasket is to seal two imperfect surfaces. However, there are limits on the degree of imperfections that can be successfully sealed with a gasket. One of the imperfections in flanges is bowing or warping of the flange surface. Flange bowing or warping can be caused either by heat during the welding process or by excessive bolt loads during installation.

Heat during the welding process

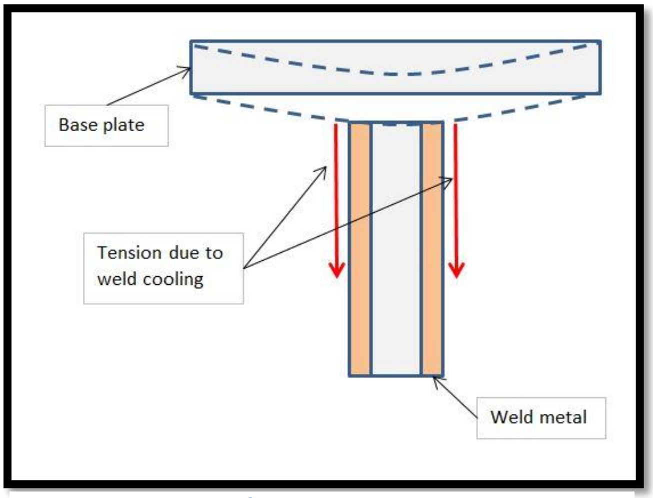

Figure 25: Depiction of Weld Stress on Base Plate

Warping of a base plate, or weld distortion, is caused by heat from the welding arc. It is a result of the expansion and contraction of the weld metal and adjacent base metal during the heating and cooling cycle of the welding process. The weld metal is deposited at a temperature above the melting point of the material. As both the weld metal and the adjacent base metal return to room temperature, the weld metal is restrained from shrinking to its normal volume by the base metal. This creates a high-residual tensile stress, which causes the weld to behave like a stretched rubber band against the base plate (*see Figure 25*). Once any workpiece restraints are removed, the weld metal will shrink along its length, and the base metal will be pulled in the same direction. If proper techniques are not employed, the base metal will distort upon the removal of any restraints.

Excessive Bolt Loading

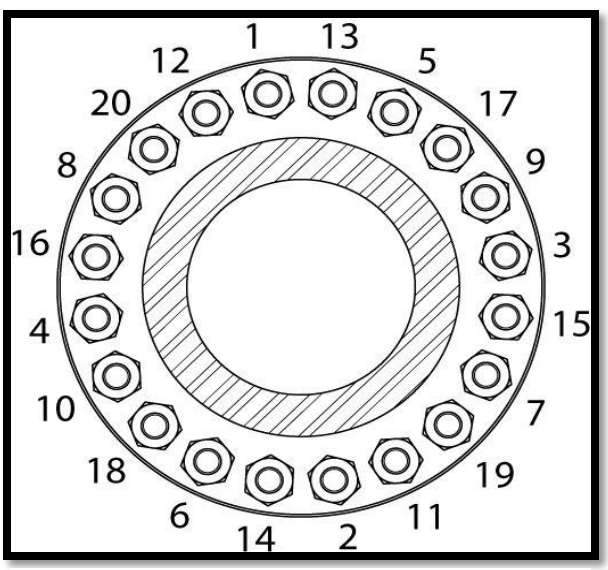

Figure 26: Numbered Sequence for a 20-Bolt Flange

To obtain a flange seal, it is necessary that basic procedures are followed during installation. The proper procedure would include inspecting all of the components after the gasket is centered on the flange. Bolts are then hand-tightened using a star-shaped configuration (*see Figure 26*). The sequence is repeated using progressively elevated torque levels until every bolt has been tightened to 100 percent of the required torque value, as established by the designer of the flange system.

Flanges can become distorted when flexing occurs at the flange, usually due to excessive bolt loads, which leads to leakage at points where compression is too low for sealing (*see Figure 27*). Excessive bolt load can also rotate flanges so much that the gasket is unloaded, opening a leak path.

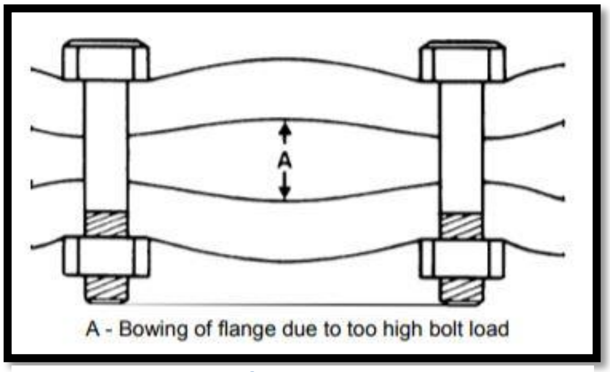

Figure 27: Depiction of Flange Bowing Due to Excessive Bolt Loading

Injuries and Personal Protective Equipment (PPE) Usage

Injuries

As a result of the fire, three personnel on the platform sustained burn injuries. IP-1 was in a crouched position near the heater treater fire tube air intake (*see Figure 28*), facing away from the heater treater at the time of the incident. His forearms were resting on his knees with his palms down. He was wearing the prescribed FRC (sleeves down), hardhat, safety glasses and rubber chemical gloves. When he turned and saw the flame come from the area of the heater treater flame arrestor / burner he was suddenly engulfed in the flame until exiting it on the west side of the heater treater. He sustained second degree burn injuries to the exposed areas of his neck and face, as well as to the upper surface of both hands, some of which was exacerbated by the post-incident removal of the rubber gloves that had melted to his hands. He indicated that there were no burns to the palms of his hands.

IP-2 was standing on an access landing between the oil tanks on the cellar deck, having opened the thief hatch on the dry oil tank and was waiting for IP-1 to feed him a hose. At the time of the incident, he was wearing safety glasses and a hard hat, but he was not wearing safety gloves and he had the sleeves to his FRC shirt rolled up. When the fire surrounded him, being aware of the fuel source, he shut the hatch, jumped off of the access landing, and ran up to the main deck. Once the fire was out, he discovered that he sustained first and/or second degree burns to his right forearm and around his watch on his left arm. Part of his beard and hair were singed, and the head piece on his hard hat was melted in.

IP-3, who was not involved in the task, had just begun his tour (noon to midnight). He was on the main deck between the heater treater and the tool shop involved in a discussion with IP-1. At the onset of flame propagation, IP-3 was on his feet facing the heater treater and sustained first and/or second degree burn injuries to his hands and the side of his face. IP-3 stated that he also fell on the grating when he stepped backward and stumbled to avoid the flame. He then rose to his feet and proceeded to the north stairwell where he depressed the ESD button.

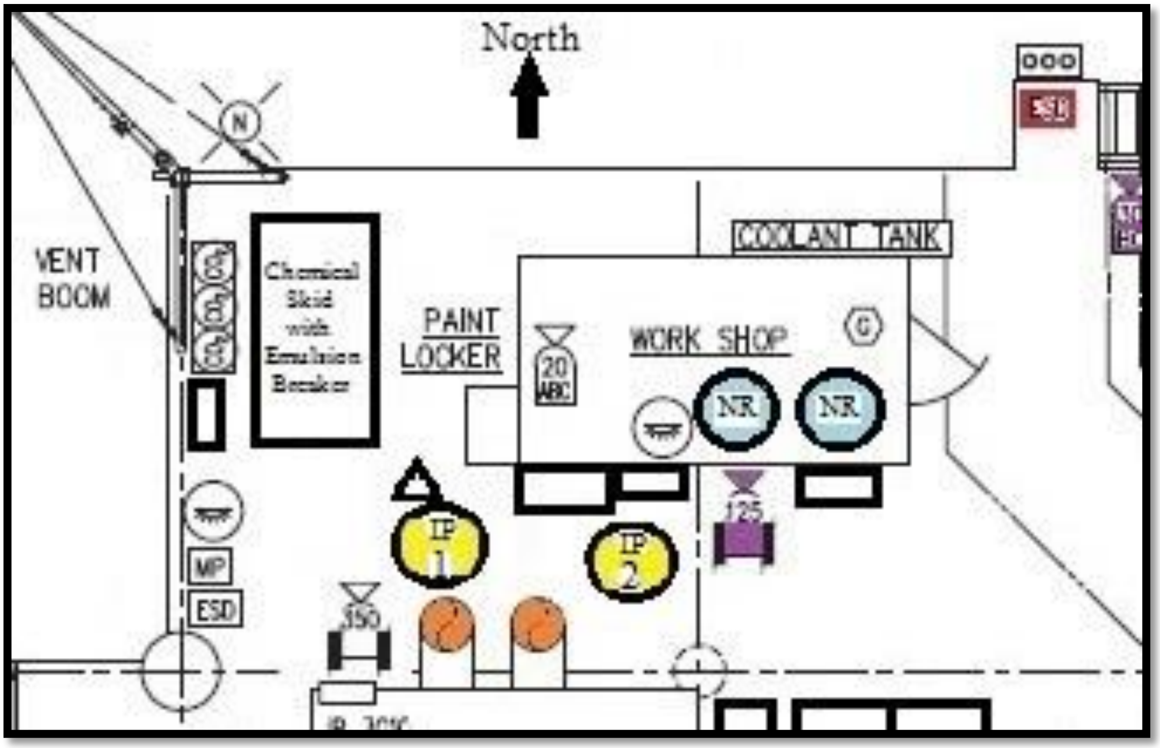

Figure 28: Approximate Positions of IP-1 and IP-2

In addition to receiving first aid treatment from platform operators immediately after the incident, the three individuals were evacuated via helicopter within 90 minutes of the incident to an onshore hospital, where they arrived within an hour of departing the platform. One was released to go home shortly after arriving at the hospital. The other two were moved to a burn unit in another hospital. Those operators were released within two days of the incident, although additional treatment following their release was necessary.

PPE

LLOG policy states that all personnel working for LLOG will wear the PPE deemed appropriate for the job task and work site. Contract companies are responsible for providing the required PPE for their personnel. Contractors must also abide by the recommended PPE on the Safety Data Sheets (SDS) for the material they are handling.

The SDS for Surfactant 00610, the emulsion breaker used for this batch treatment, identifies skin corrosion and serious eye damage as hazards when using this chemical. The PPE listed on the SDS to mitigate the hazards are as follows:

- Eye protection – Safety goggles and face shield
- Hand protection – Impervious butyl rubber gloves
- Skin protection – Protective clothing (in addition to safety goggles and gloves)

According to their SEMS bridging agreement, operators were responsible for following Wood Group's safe work practice (SWP) standard for PPE.[13] LLOG and Wood Group generally required the following PPE to be worn by all personnel involved in field operations at the work site:

- Head protection – hardhats must comply with American National Standards Institute (ANSI) Standard Z89.1.
- Eye protection – safety eyewear must meet ANSI Standard Z87.1. Eye protection is required at all times when outside of living quarters.
- Foot protection – safety footwear must meet ANSI Standard Z41.
- Hand protection – the appropriate glove must be worn to match the hazards identified for the specific task.
- Hearing protection – must be worn in designated areas requiring hearing protection.
- Protective clothing/Fire-resistant clothing (FRC) – see below.

Regarding hand protection, Wood Group's SWP for PPE indicated that gloves shall be used whenever personnel's hands are exposed to hazards such as, among others, those from skin absorption of harmful substances and chemical burns. The selection of the appropriate type of gloves to be worn will be made based upon the task(s) to be performed, conditions present, duration of use, and the hazards and potential hazards identified. In addition, gloves shall be worn for hand protection in any situation where exposures to hazards exist, including as indicated on the SDS for the material.

Wood Group's SWP for PPE indicated that employees shall use appropriate eye and/or face protection when exposed to eye or face hazards from, among other things, liquid chemical, acids or caustic liquids, or chemical gases or vapors; and that combination face shield and safety glasses were required during any operation in which splashing, spraying, or projection of material was probable.

LLOG policy dictates the wear of protective clothing by all personnel while working in the vicinity of production and/or drilling equipment. FRC is only required based on the incident energy exposure identified with the specific task; however, it is required for all electricians and automation specialists, and it may be required when a high risk of flash fires exists. The following bullets list the key elements of protective clothing required:

- Long-sleeved, button-up shirts, overalls, coveralls, and jeans are acceptable and must be made of cotton.
- Clothing must be properly fitted without holes, tears, or significantly loose material. Sleeves must be fully extended and shirts completely tucked into pants.
- Appropriate protective clothing will be worn specific to the SDS when handling chemicals or hazardous substances.

[13] All three IPs were employed by Wood Group.

In addition, Wood Group's SWP for FRC indicated that FRC shall be worn in, among others, 'production classified areas' on production platforms, where the task risk assessment mandates the use of FRC then same shall be worn whether the job site is in a classified area or not; and any owned/operated site in which the risk of injury to personnel from flash fires is present – based on local site standards, client requirements or task specific risk assessment. It further described that that the sleeves and legging of FRC shall be completely rolled out to wrists and ankles respectively, since FRC only provided protection where it separated the wearer from the flash fire.

For the task of "circulating the emulsion pad from treater and oil tanks," the September 8, 2016 JSA prescribed the following PPE: hard hat, ear plugs, safety glasses, safety shoes, FRC, leather gloves, and rubber gloves.

IP-1, who intended to operate the chemical tote tank valve, was wearing FRC, safety glasses, hard hat and rubber gloves (instead of leather gloves), as the SDS for Surfactant 00610 recommended wearing impervious butyl rubber gloves. IP-2 was wearing a hard hat, safety glasses, ear plugs and the prescribed FRC; however, he had his sleeves rolled up, decreasing the amount of FRC coverage, and he was not wearing gloves. Neither IP-1 nor IP-2 were wearing a face shield for their intended work activities. IP-3 was not wearing any gloves at the time of the incident. At the time of the incident, he was wearing the prescribed FRC (sleeves down), hardhat and safety glasses; which was appropriate for walking around the platform's deck.

Safety and Environmental Management Systems (SEMS)

The SEMS Bridging Agreement between LLOG and Wood Group contained the following relevant stipulations:

- All activities performed by the Contractor will be conducted in accordance with the requirements in LLOG's SEMS program and the Contractor's Safe Work Practices;
- The Contractor has SWPs for all work, except "domestic services," and that those SWPs must meet LLOG expectations.
- Task level JSA will be conducted by WGPSN operators using the LLOG JSA form.
- Safe Work Practices and their responsible parties are dictated as follows:
    - Opening of Pressurized or energized equipment or piping (LLOG)
    - Permit to Work (LLOG)
    - Job Safety Analysis (WGPSN will follow LLOG JSA policy)
    - Personal Protective Equipment (WGPSN)

Hazards Analysis

The LLOG SEMS Program delineates the company procedures for the different levels of hazards analysis. The procedure for the task level hazards analysis, or JSA, determines the appropriate mitigation measures needed to reduce job risk to personnel. A JSA at the task level shall be performed by appropriate personnel on all LLOG owned or operated facilities for activities as outlined in their SEMS.

LLOG employs the use of a Hazard Identification Tool (*see Figure 29*) in identifying potential hazards and subsequently, the development of preventative strategies and controls. While a hazard analysis is usually conducted remotely by project management, LLOG expects that all employees and contractors will use the Hazard Identification Tool when identifying hazards associated with work to be completed.

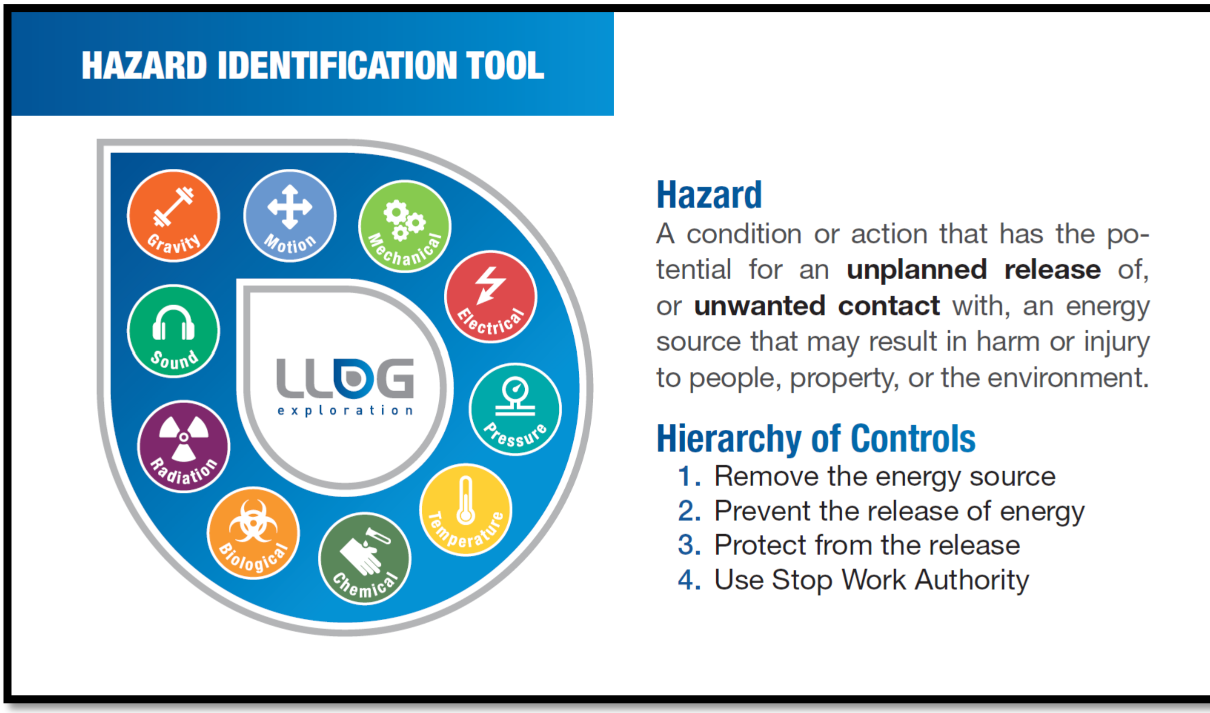

Figure 29: LLOG's Hazard Identification Tool

LLOG policy states that the PIC must complete a pre-job safety meeting at the beginning of each workday, new job, or a change in operations. It also stipulates that Contractors shall conduct and/or actively participate in onsite safety meetings daily. These meetings are intended to include hazard and job safety analyses for all work.

Safe Work Practices

At the time of the incident, LLOG's process for informing its contractor personnel of its SWPs was via their short service employee (SSE) program. LLOG's Operations Manager stated that SSE personnel served a probationary period, where they were evaluated and exposed to LLOG's SWPs. He also stated that SWP "Quick Guides" were given to everyone during a company meeting in June 2016, and he discussed the responsibility of PICs to teach SWPs.

The Operations Manager stated that all LLOG SOPs were available on each platform's shared drive. LLOG also gives all of its contractors an online link to access LLOG SOPs. The panel found that there were no SOPs for draining the oil pad work and/or the batch treatment work. The only procedures describing this task were in a September 8, 2016 JSA for "circulating emulsion pad from treater and oil tanks."

When asked about any SWP involving the opening of pressurized equipment, LLOG provided the panel with their Energy Isolation SWP standard. This document states that its purpose is to ensure that energy isolation and/or opening of equipment is performed in a safe and controlled manner. Work involving Isolation of Energy must meet the following relevant criteria and requirements:

- A qualified Standard Operating Procedure describes the work scope.
- Energy Isolation Permits must be used in conjunction with a PTW.
- Regarding managing hazards, process equipment should be depressurized into a safe area such as a flare system or recovered oil system. Depressurizing into a closed system is the best practice.
- Facility management shall conduct periodic audits and verification to ensure compliance to this standard.

Permitting

LLOG requires that a Permit to Work (PTW) be issued whenever the work to be conducted may adversely affect health, environment, safety, efficiency, or reliability of associated personnel or an asset. They are not intended for low-risk activities in low exposure locations/settings. LLOG does, however, delineate specific instances for which a PTW is required, one of which is when work or maintenance is performed in a process area that involves breaking into a line, equipment or vessel that contains actual or potential hazards.

The investigation panel received no indication that either a PTW or an Energy Isolation Permit was issued for the assigned task on November 12, 2016. The PIC at the time of the incident, however, did previously issue a PTW (no Energy Isolation Permit) for the same task on September 8, 2016 during a previous work rotation, which included IP-1.

Job Safety Analysis (JSA)

The Platform Offshore Installation Manager (OIM)/UWA is responsible for reviewing and approving all JSAs.   The WTL is responsible for the following:

- Facilitating the development, review, and documentation of JSA's with their personnel to carry out the policy.
- Utilizing the JSA during daily safety meetings with their personnel.
- Jointly performing and reviewing with their personnel the JSA as it applies to affected personnel.
- Change or develop of new JSAs as conditions warrant.
- Approve the JSA prior to the commencement of the work.

The LLOG or Contractor employee is responsible for the following:

- Listing specific detailed steps of the activity from start to finish
- Physically visiting the job site to uncover and evaluate potential hazards for each step.
- Incorporating the results of Safety Meetings and JSA data into daily activities with recommended action to prevent hazards, injury/illness, or environmental impact.
- Advising the WTL when conditions or situations of the task change.
- Everyone participating is [sic] the JSA is required to sign off on the JSA and attach completed permit to work forms.

The LLOG JSA process may be required based upon the complexity of the job, the number of personnel involved, and the hazards that may be encountered or non-routine task. Specifically, the LLOG SEMS program requires a JSA be performed for, among others, jobs requiring opening of process piping or equipment.

LLOG does not have a written procedure outlining the steps of the task being performed at the time of the incident. The only written reference to the task being performed at the time of the incident that was provided to the panel was a JSA that was conducted on September 8, 2016. However, operators explained that many of the activities described in this JSA were performed frequently.

The September 8, 2016 JSA provided to the panel referred to the task as "Circulating Emulsion Pad from Treater and Oil Tanks." The task generally consisted of draining the desired fluid amount from the heater treater into the dry oil tank and batch treating the tank contents with a chemical. Figure 30 outlines the work sequence, identified hazards, and hazard mitigation recommendations from this JSA.

Work Sequence (Job Steps)	Hazards or Potential for Incident	Recommendations to Eliminate or Reduce Hazards
Do JSA, Permits and hold safety meeting	Poor Communication	Everyone on the same page, use of radios
Isolate inlet and outlet of vessel and turn off burner	Inflow exceeding outflow, LSL in media causing TSH, Too much fluid from treater to oil tank	Isolate inlet and outlet valves. Monitor make up gas pressure. Shut treater burner off
Hook up hoses to vessel	No gasket in hose connection, spills, pressure	Check hose before use for gaskets and condition. Have oil pads on hand for drips or spills. Check hose for trapped pressure.
Transfer fluid from vessel to tank. Batch treat with chemical as needed.	Opening tank to atmosphere, vapors, LSL in the treater. LSH in the oil tank. Not reviewing SDS before working with chemical, getting chemical on you	Checking hatches and not being in the line of fire for flash gas vapors. Monitoring fluid level, treater. Monitoring fluid level in oil tank for LSH. Review SDS for treatment chemical used and wear proper PPE when treating with chemical.
Clean up after task for good housekeeping	Oil in skids and hoses left out	Put up all tools and dispose of oil pads. Clean up work area real good. Roll up hoses that are used.

Figure 30: Critical Job Steps from September 8, 2016 JSA for "Circulating Emulsion Pad from Treater and Oil Tanks"

The first step in the work sequence for this task is "Do JSA, Permits, and hold safety meeting." By all accounts, this step did not occur on November 12, 2016 for this task, increasing the potential of encountering "Poor Communication." All of the Operators assigned to the task were equipped with radios and were familiar with the task. However, on November 12, 2016, the operators were not of the same understanding on what they were going to do, as some believed they were going to drain the pad from the heater treater to the dry oil tank prior to batch treating; and another intended only to batch treat the dry oil tank with an emulsion breaker. Further, the exact method for batch treating that they were attempting (by feeding the one-inch chemical hose through the grating above the dry oil tank) had not been done before.

The second step of the work sequence is "Isolate inlet and outlet of vessel and turn off burner." The vessel referenced in the JSA is the heater treater. If inlet and outlet valves are not isolated then the level within the heater treater could get too high (causing a Level Safety Switch – High (LSH) to activate), or get too low (which should activate the Level Safety Switch – Low (LSL)[14] and/or TSH). Activation of the TSH, LSH or LSL during this process would result in unintentionally shutting in most of the platform. Although the PIC did shut in the LLOG wells at the boarding chokes, there is no indication that any other isolation was performed to the heater treater prior to the incident, including turning off the burners.

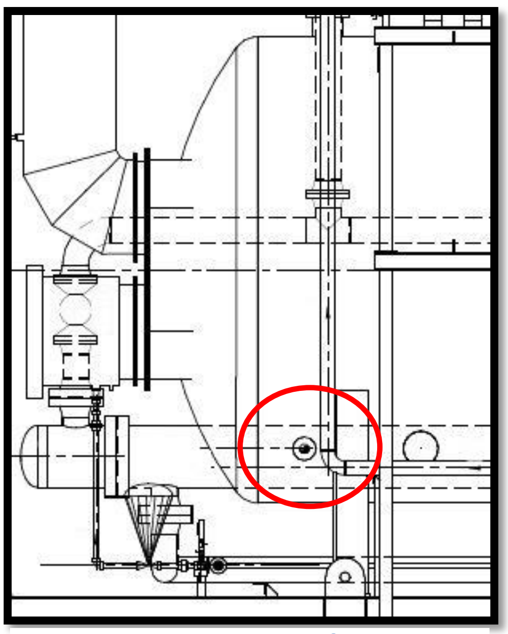

Figure 31: Partial Schematic of Heater Treater, with Location of 2-inch Front End Sand Jet Nozzle

The third step of the work sequence is "Hook up hoses to vessel." In preparation for the fourth step (transfer fluid from the vessel to tank), a hose would be connected to the front end two-inch sand jet nozzle (*see Figure 31*). The hose would then be routed to the cellar deck, where it is inserted into the thief hatch opening of the dry (wet) oil tank. While the incident occurred prior to this step in the process, one of the IPs stated that he intended to try to treat the dry oil tank and the heater treater really fast with the chemical emulsion breaker, maybe eliminate the BS&W issue and come back online, which omitted this step.

The fourth step in the work sequence is "Transfer fluid from vessel to tank. Batch treat with chemical as needed." The first two identified hazards associated with this step are "opening tank to atmosphere" and "vapors," both of which contributed to the incident event. The recommendations to eliminate or reduce these particular hazards are "checking hatches and not being in the line of fire for flash gas vapors."

The actual performance of this fourth step consists of additional activities that are not listed on the JSA. As explained by platform operators, the general process of transferring fluid (oil and emulsion) from the heater treater vessel to the dry oil tank requires the following additional steps: (1) open the thief hatch on the dry (wet) oil tank, (2) route the

[14] The bypass and out of service history indicated that the bypasses for the LSLs in the heater treater were enabled on the evening of November 11, 2016, and had not been disabled at the time of the incident.

hose into the thief hatch opening, and (3) open the ball valve attached to the sand jet nozzle. Once the emulsion pad (fluid) is drained into the tank, the ball valve is closed.

At this point, the process of "batch treating with chemical" commences, if needed. According to personnel who have performed this activity, the process typically involved filling a bucket with the prescribed amount of chemical and dumping the bucket into the dry oil tank through the thief hatch opening.

The order of steps in the work sequence indicates that the heater treater would be isolated prior to opening the thief hatch on the tank. In the second step, the job sequence listed as "isolate inlet and outlet of vessel" is explained in detail by LLOG under the "Normal Shutdown and Isolation: Heater Treater" procedure, which includes the natural draft burners. The procedure contains 23 steps, and consists mainly of (1) performing a hazards analysis, (2) verifying and communicating that all sources of flow into the vessel have stopped, (3) verifying all incoming shutdown valves are closed, (4) verifying all outgoing valves are closed, (5) bleeding off any trapped gas, and (6) draining liquids from the vessel.

Industry Recommended Practices and Standards

NOTE: API publications, unless incorporated by reference into 30 CFR 250, address problems of a general nature, and are not intended to meet the duties of employers, manufacturers, or suppliers to warn and properly train and equip personnel concerning health and safety risks and precautions. With respect to particular circumstances, local, state, and federal laws and regulations should be reviewed.

1. API RP 12N, "Recommended Practice for the Operation, Maintenance and Testing of Firebox Flame Arrestors"

Section 5 of this RP refers to maintenance and inspection of firebox flame arrestors. Section 5.2 states that any air path from the exterior into the fire tube which does not pass directly through the arrestor can represent an impediment to proper operation of the unit. Visual inspection for unplugged holes or loose mounting flanges, which can cause a flash through, should be performed each time the equipment is approached.

2. API RP 14C, "Analysis, Design, Installation, and Testing of Safety Systems for Offshore Production Facilities" (7th Edition, Reaffirmed March 2007)

Figure 32 below is an excerpt from the Safety Analysis Table (SAT) for fired components with natural draft burners, like the heater treater on the platform. It highlights the undesirable event, possible causes, and the detectable abnormal condition applicable to this incident.

Undesirable Event	Cause	Detectable Abnormal Condition at Component
Direct ignition source	Flame emission from air intake Spark emission from exhaust stack Excess stack temperature Exposed hot surface	External fire High-temperature stack

Figure 32: Excerpt from Table A.11 from API RP 14C (Safety Analysis Table: Fired Components, Natural Draft)

The Safety Analysis Checklist for fired and exhaust-heated components states that the temperature in the burner exhaust stack should be monitored by a TSH sensor to shut off the fuel supply and the inflow of combustible fluids. It also states that the stack on a natural draft burner should be equipped with a stack arrestor to prevent spark emission. The stack arrestors on fired components should be located to prevent spark emission from the exhaust stack.

Section 4.2 discusses protection concepts, one of which is "Ignition Prevention Measures" (IPM). While the principal threat to platform safety is the release of hydrocarbons, the consequences of hydrocarbon release can be reduced by preventing ignition. The IPMs listed include (1) ventilation, and (2) location of potential ignition sources. For ventilation, API RP 14C recommends to provide a volume of air sufficient enough to maintain the hydrocarbon concentration below the LEL. For location of potential ignition sources, it recommends to locate fired process components and certain rotating machinery in areas where exposure to inadvertently released hydrocarbons is minimized. Section C.2.2.1 reiterates these methods, stating that safe locations for final gas release to the atmosphere should be located where the gas will be diluted with air to below the LEL so it will not be threat to the facility.

3. API RP 14J, "Recommended Practice for Design and Hazards Analysis for Offshore Production Facilities"

Section 5 of this RP discusses platform equipment arrangements. It states that a general rule for equipment layout planning is to keep potential fuel sources as far from ignition sources as practical. Table 3 in Section 5 notes that hydrocarbon storage tanks (dry oil tank/wet oil tank) are considered fuel sources, and fired vessels (heater treater) are considered ignition sources. Section 2.3.2 notes that large abnormal releases could result in a hydrocarbon cloud being ignited by devices located in a "safe area," and the potential for such releases should be considered in a hazards analysis.

4. API STD 2000, "Venting Atmospheric and Low-pressure Storage Tanks"

This standard defines "normal venting" as that required because of operational requirements or atmospheric changes. "Emergency venting" is defined as that required when an abnormal condition, such as ruptured internal heating coils or an external fire, exists either inside or outside of a tank.

The means for normal venting for pressure and vacuum shall be accomplished by a pressure vacuum (PV) valve or an open vent with or without a flame-arresting device. The wet and dry oil tanks on the platform share a common PV valve, designed to relieve pressure at 16 ounces per square inch, which relieves into an atmospheric vent header. The standard lists several means for emergency venting, one of which is by the use of a gauge [thief] hatch that permits the cover to lift under abnormal internal pressure. There is no stipulation in this standard that acknowledges or advocates the use of venting through a thief hatch, other than for emergency purposes.

5. NFPA 69, “Standard on Explosion Prevention Systems”

Section 15.7 addresses the inspection intervals for explosion prevention systems, including flame arrestors. At a minimum, it states that systems shall be inspected and tested at 3-month intervals. The maximum inspection and test interval shall not exceed two years.

Conclusions

The following conclusions were based upon the information provided to, and reviewed by the panel, during its investigation into the November 12, 2016 incident. For the purposes of this report, the direct (immediate) causes are the events or actions immediately preceding the incident event and without which the incident would not have occurred. Indirect causes are those causes or conditions leading to the incident event that, if corrected, would have prevented the incident. Contributing factors are those that contributed to the incident event, but, by themselves, would not necessarily have prevented the incident.

Direct Cause

- The fire occurred when a flammable gas mixture, which was released through the thief hatch on the dry oil tank, migrated into the left fire tube, where it contacted either the left fire tube flame or the left burner pilot flame. This flame likely propagated through a gap in the mating flange between the left flame arrestor housing and the heater treater, igniting the flammable gas mixture in the surrounding atmosphere.

When the thief hatch on the dry oil tank was opened, a mixture of blanket gas and flash gas from both tanks was flowing into the surrounding atmosphere. The wind conditions at the time dispersed the vapors into a flammable mixture and forced that mixture into the vicinity of the heater treater flame arrestors.

The panel presented several findings regarding possible ignition sources. While the panel acknowledges other possible ignition sources, the panel concludes that the most likely source of ignition occurred when the flammable mixture migrated into the left fire tube and ignited by contacting either the burner pilot flame or the fire tube flame. This flame then propagated through a gap in the mating flange, igniting the remaining flammable mixture external to the fire tube.

These conclusions are supported by the existence of a sufficient gap (1/4 inches) in the mating flange between the firebox flame arrestor assembly and the heater treater flange, creating a flame path to the surrounding atmosphere and rendering the flame arrestor ineffective. Further, two witnesses stated that they saw the flame originate in the area of the flame arrestors. Finally, the alarm history showing both BSL alarms tripping prior to the TSE alarm implies the existence of an abnormality inside the fire tubes occurring prior to an external fire.

Indirect Causes

- Personnel failed to sufficiently mitigate hazards.

LLOG provided a JSA dated September 8, 2016 for "Circulating Emulsion Pad from Treater and Oil Tanks." One of the stated critical steps is to "isolate the inlet and outlet of vessel and turn off burners." Had the operators followed these steps on the incident date, they likely would have eliminated the heat source for the fire by turning off the burners.

- Lack of sufficient engineering controls.

The panel concluded that certain engineering controls should have been implemented that would have prevented this particular incident from occurring. At the time of the incident, neither the dry nor wet oil tanks had an enclosed flow path from the heater treater for draining purposes. Also, neither tank had an enclosed flow path from any chemical totes for batch treating purposes. The existence of a contained flow path into the oil tanks from both the heater treater and the chemical totes would have eliminated the necessity to open the thief hatch, which should only be used for emergency venting per API STD 2000, eliminating the release of flammable gas into the surrounding atmosphere.

During normal operations, the closed thief hatches on the dry and wet oil tanks relieve gas to the surrounding atmosphere, which is considered an adequately ventilated area. However, IPMs listed in API RP 14C specify that inadvertent hydrocarbon releases be considered when locating potential ignition sources, such as fired heaters, and that the location(s) are such that they are not a threat to the facility. Had the heater treater burner assembly been located outside of the LEL envelope of the dispersed gas, the incident would not have occurred.

- The gap in the flame arrestor/heater treater mating flange was likely caused by improper installation and/or assembly of the mating flange.

Flange bowing occurred on the mating flange, either due to improper welding, improper bolting procedures, or a combination of both. The panel considered the following possibilities, based on technical research.

  - The bolt torques used may have been specified for carbon steel, and not the adjacent aluminum flange, causing the aluminum to deform.

  - Imperfections in the flange face due to welding may have been expected to have been remedied by using a mating flange with excessive bolt torque.

  - The bolt tightening sequence may not have been as prescribed, causing excessive misalignment.

Contributing Factors

Based on the regularity with which draining the heater treater and batch treating in the oil tanks were occurring, the routine nature of these processes possibly led to a feeling among the crew that abnormal conditions were becoming the norm. Some personnel felt that the frequent batch treating, draining, and the use of steam were all temporary solutions to long-term problems. In addition to contributing to the incident, the following contributing factors are also reflective of a poor safety culture existing at GI Block 115 at the time of the incident.

- Failure to follow OEM recommendations, industry recommended practices, and industry standards.

The OEM for the flame arrestors prescribes several protocols that, had they been followed, may have prevented this incident. Had the flame arrestor been properly inspected, either for routine maintenance or current operation, at some point since the unit was returned to service, it is possible that the gap in the mating flange would have been detected and repaired. This would have removed the path for flame propagation, and the incident would likely not have occurred. Also, if the stack arrestors were inspected, then the damage to the stack arrestor and housing would likely have been discovered.

Additionally, the panel concludes that the thief hatches on the oil tanks at GI Block 115 are intended to be used, per API STD 2000, as emergency venting devices. Had the incident crew adhered to this standard (i.e., using the thief hatch only for emergency venting), the fuel source would not have been released into the surrounding atmosphere.

- Personnel failed to adhere to permitting requirements.

Because the personnel involved with the operations relevant to the incident considered the task to be "normal daily operations," they did not complete a JSA; nor did they complete a PTW. Likewise, as there was no established procedure, they did not obtain an Energy Isolation Permit. LLOG does have an SOP for isolating equipment, and at least one crew from a previous rotation used a JSA in the performance of the intended task. The panel concludes that a PTW, as well as an Energy Isolation Permit, was warranted in this situation.

The equipment configuration at the time of the incident necessitated that personnel open the thief hatch in order to batch treat an emulsion pad. However, one of the "best practices" listed in the Energy Isolation SWP is to depressurize into a closed system. Enclosed paths from the heater treater and chemical tote tanks into the oil tanks would eliminate the requirement to open the oil tanks. However, all operators involved with this activity should have been operating with an Energy Isolation Permit absent any contained flow path into the oil tanks.

The requirement for opening process equipment, coupled with the existence of a JSA on a previous date, leads the panel to conclude that there should be some form of job procedure outlining the procedural steps for circulating and batch treating an emulsion pad from the heater treater.

- The hazard analysis performed for the work to eliminate the emulsion pad was insufficient, as the incident crew not only neglected to perform a JSA, but also failed to hold a pre-job safety meeting.

Since LLOG requires a JSA prior to opening process equipment, a written JSA should have been completed prior to performing the task of draining the emulsion pad and/or batch treating. This would have at least ensured that all operators involved with the task were aware of the job steps, hazards and hazard mitigations, particularly since at least one operator intended on trying something different.

Another instance of insufficient hazard analysis was the lack of a pre-job safety meeting at the job site. The two operators involved in the task did not communicate as to the full scope of the task, nor did they identify or mitigate hazards associated with the task. The panel recognizes that LLOG does allow a "verbal" JSA (undocumented) to be conducted for low-risk work. However, the panel concludes that the task of circulating and batch treating an emulsion pad from the heater treater does not constitute "low-risk work," especially since it requires the opening of process equipment.

- The improper use of PPE resulted in injuries that may not have occurred had proper PPE procedures been followed.

Multiple references dictate the prescribed PPE for the activity in which the IPs were engaged. IP-3, who was not involved in the task, was in compliance with LLOG policy. IP-1 was mostly in compliance, lacking a face shield as prescribed by the SDS. IP-2 should have not only been wearing a face shield as prescribed by the SDS, but also had his FRC sleeves rolled up, contrary to LLOG and WGPSN policies. Had IP-2 had his sleeves rolled down, he likely would not have received the extent of the burn injuries to his forearm that he did.

- Daily safety meeting failed to sufficiently address operations and hazards on the day of the incident.

The panel received varying accounts on whether or not the PIC held a safety meeting on the morning of the incident. Also, the panel received no documentation of a safety meeting that morning, and no one could provide any specifics on what was discussed that morning. Regardless, the fact that there were personnel working that shift without attending a safety meeting that morning means that there were likely some personnel who were unaware of the full scope of operations on the platform that day.

- Insufficient supervision.

The panel concluded that LLOG provided its contractor personnel with access to LLOG SWPs, specifically regarding safety meetings, PTWs, and JSAs. The panel concludes that the incident PIC likely did not hold safety meetings on a daily basis, per LLOG policy. Additionally, the panel notes that the permitting and hazard analysis processes at the platform are inconsistently performed, and sometimes may be in violation of LLOG policy. By failing to adequately communicate the scope of work to the crew, and being unaware of the intentions of the WTL, the PIC did not sufficiently exercise the control of work necessary to properly address the hazards associated with the task.

- Poor communication.

Prior to the incident, the PIC thought the operators were going to shut in topside equipment, whereas none of the operators had acted to do so. At least one operator was not aware that the wells had already been shut in. One operator intended to use a different procedure than they, as a crew, used previously. Another operator did not understand what specific task they were doing. These communication issues are exacerbated by the fact that LLOG did not provide any specific procedure for this particular task. Also, open and constant communication should have been maintained between the IPs and the PIC as to what equipment, if any, was to be shut in before the job. The panel concludes that the lack of effective communication, both written and oral, contributed to the incident.

- Unfavorable environmental conditions.

The location of the heater treater in relation to the oil tanks, when combined with the wind conditions and the presence of a flame propagation path, possibly contributed to the vapor cloud migrating into the heater treater burner assemblies. In this instance, the wind speed and direction sufficiently dispersed the gas mixture released from the dry oil tank into a flammable gas mixture, which ignited once it reached a sufficient heat source.

- Equipment failure

API RP 14C requires the use of a stack arrestor and a TSH in a natural draft burner. The absence of a stack arrestor may have resulted in the emission of hot sparks from the right stack. Also, the discovery of a TSH element as “hot and scarred” may have rendered the TSH inoperable as a safety device. The panel concluded that the damage to the TSH, as well as the damage to the right stack arrestor, was likely caused during a “rich tube ignition” event that occurred at some point prior to the incident. The panel also concluded that the damage to the left stack arrestor was likely a result of prolonged exposure to excessive heat.

While the panel concluded that the likely cause of the fire was directly due to the gap in the mating flange, the panel could not conclusively eliminate a spark emission from the stack as a potential cause. This contributing factor would only be relevant in the event that a spark emission was the direct cause of the incident.

Recommendations

The results of the BSEE panel investigation yielded a number of recommendations aimed at improving safety and preventing a recurrence or similar event sequence. The BSEE Panel recommends companies operating on the U.S. Outer Continental Shelf consider the following recommendations to further promote and protect the health and safety of personnel, the environment and its resources:

- Consider the location(s) of fired elements relative to potential gas releases when performing facility-level hazard analyses.

- Consider the use of permanent containment systems for vessel draining and chemical treatment.

- Consider conducting visual inspections of natural draft burners, ensuring airtight integrity between flame arrestors and fire tubes.

- Consider the use of a portable gas detector when operating in the vicinity of fired vessels.

- Consider increasing operator supervisory presence when using contractor-employed supervisory personnel during non-routine operations.

- Consider ensuring production SOPs are used for site specific equipment and/or conditions.

- Ensure operators are familiar with, and adhere to, OEM instructions regarding start-up, operations, maintenance, and inspection of fired vessels and associated safety devices.

- Consider instituting applicable industry standards into inspection programs, SOPs, and SWPs.

- Ensure all contractor personnel engaged in production operations are knowledgeable regarding operator SWPs.

- Ensure that all company, contractor, and visiting personnel properly wear PPE where the potential exists for thermal exposure from fire, and that the PPE selected for the job reflects the probable and possible hazards of the job.