Safety and Oil Spill Prevention Audit

DCOR, LLC
Platform Esther

California State Lands Commission

October 2016

Safety and Oil Spill Prevention Audit

DCOR, LLC
Platform Esther
Seal Beach

TABLE OF CONTENTS

3.0 ELECTRICAL SYSTEM AUDIT

4.0 SAFETY MANAGEMENT PROGRAMS AUDIT

5.0 HUMAN FACTORS AUDIT

6.0 APPENDICES

Executive Summary

DCOR, LLC
Platform Esther
Seal Beach

Executive Summary

Safety Audit of Platform Esther

A Safety and Oil Spill Prevention Audit of DCOR's, Seal Beach Platform Esther started in October 2014 with fieldwork completed in March 2015. The Electrical portion of the audit was finished in August 2015. Similar audits of Platform Eva and Fort Apache (Ft. Apache) were completed concurrently and are subjects of separate reports.

The objective of the Safety and Oil Spill Prevention Audit is to ensure that oil and gas production facilities on State leases operate in a safe and environmentally sound manner. Facilities must comply with both state and federal regulations and meet the Best Achievable Protection requirement of Public Resources Code (PRC) 8755. The audit followed the established procedures used by CSLC for many years. Audit findings reference the applicable regulations and standards listed in Appendix C.

Company Background

DCOR, LLC is the current owner of Platform Esther and holds interest in the state oil and gas leases at the Seal Beach location. The company was formerly was known as Dos Cuadras Offshore, LLC and changed its name to DCOR, LLC in July 2005. DCOR was founded in 2001 and is based in Ventura, California with additional offices in Bakersfield, Huntington Beach, Los Angeles, Santa Barbara, California, and Dallas, Texas. DCOR's operates eleven offshore platforms. The company is owned and controlled by Mr. William M. Templeton.

Facility Description

Platform Esther is an offshore oil and gas production facility operating within the boundaries of California State Waters in the Belmont Oil Field. The facility is located roughly 1-1/2 miles offshore of Seal Beach, California on State Lease PRC 3095.1 (Parcel 16A) in thirty-eight feet of water.

Platform Esther is a permanent, fixed base, sixty four-slot drilling and production platform. The field is producing nearly 570 barrels of oil per day, approximately 7500 barrels of water per day, and 518 thousand cubic feet per day (MCFD) of natural gas. There are 18 active producer wells and 5 active water injection wells. At least two operating personnel a shift continually operate the platform. Visitors and contract personnel vary depending on platform operations and maintenance activities.

Platform Esther first began production as a Chevron man-made island in September 1965. In March 1983, a winter storm washed away the island and facilities. Construction of a new platform on the submerged rubble began a year later and Platform Esther was commissioned in 1985. Union Oil of California (Unocal) acquired the platform from Chevron in 1988. DCOR bought the platform in 2004 and operations began in October of 2005.

The oil producing formations in the Belmont Field are typically below hydrostatic pressure, and require artificial lift (electric submersible pumps), making the potential for a well blowout minimal.

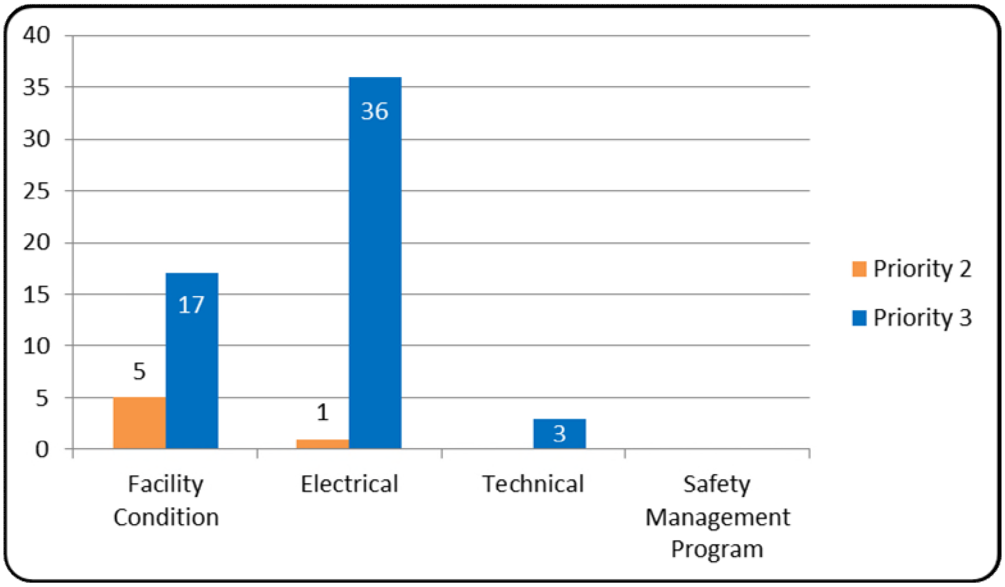
Safety Audit Results

The Safety and Oil Spill Prevention Audit found that Platform Esther complies with applicable safety and regulatory requirements. The platform appears to be in good condition and safety systems and equipment remain fit for service; however, moderate corrosion was evident in some areas, primarily steel plate flooring and walkways. The corrosion has the potential to lead to unsafe working conditions and on-site accidents. Appropriate measures are necessary to curb or minimize the occurrence of corrosion on platform decking and walkways. While DCOR has a corrosion-monitoring program in place, a more robust corrosion control program is necessary to inspect and prevent corrosion to ensure a safe and productive operation. Although corrosion seems to be an ongoing problem for the platform, repairs of steel plate flooring and walkways were taking place at the time of the audit.

DCOR has well established behavior based safety policies, health, and environmental programs. A consistent and positive safety and environmental culture is evident in DCOR employees that augments mechanical reliability, functional performance, and teamwork. The established safety culture also helps to ensure the protection of workers, the public, and the environment. Personnel are knowledgeable, and provided valuable assistance to the State Lands Audit Team.

The safety audit identified 62 action items. Equally important is the fact that no priority one items were identified. The number of priority two action items was also quite low at six, with the majority (56) being minor priority three action items. This is a favorable result since the number is on par with other comparable facilities and since the items are mostly priority three, which is the lowest rating in terms of significance or risk. Resolution of priority two action items is required within 120 days, and resolution of the priority three actions items is required within 180 days from issuance of this report.

Esther Platform action items (62) are shown on the following chart. They are identified by audit categories and priority. The distribution is similar to the other facilities in California where the items typically identified relate to piping, equipment, electrical, and system condition and maintenance.



Introduction

DCOR, LLC
Platform Esther
Seal Beach

1.0 INTRODUCTION

1.1 Safety Audit Background

The California State Lands Commission (CSLC) Mineral Resources Management Division (MRMD) conducts safety audits of lessees and operators for lands in which the State has an interest. CSLC sponsored safety audits ensure oil and gas production facilities on State leases or granted lands are operated in a safe and environmentally sound manner, comply with Federal, State, and local codes/permits, and follow industry standards and practices. CSLC staff is tasked with oil spill prevention in California's ocean and tidelands, prevention of waste, conservation of natural resources, and ensuring public safety. Public Resources Code (PRC) 6103, 6108, 6216, 6301 and 6873(d) provide authority for these endeavors.

In 1990, the California legislature enacted the Lempert, Keene, Seastrand Oil Spill Prevention Act and directed CSLC to inspect these facilities to ensure that Best Achievable Technology (BAT) standards for prevention of oil spills are met. CSLC conducts frequent inspections of onshore and offshore oil and gas drilling and production facilities to ensure that these standards are enforced to safeguard the public and environment. The Safety Audit Program, together with the monthly inspection program aids in preventing oil spills and other accidents. Added prevention efforts occur through a review of drilling, pipeline inspection, facility design, maintenance, human factors, and other aspects of safety management.

The Audit Team systematically evaluates the organizations' current performance levels and provides feedback for improvement. Their areas of emphasis include:

- Equipment Functionality and Integrity (EFI)
- Electrical (ELC)
- Technical (TEC)
- Safety Management Programs (SMP)
- Human Factors (HF)

Appropriate company contacts and resources are identified at the start of the audit. Progress and deficiency reports are communicated periodically throughout the audit process. An "action item matrix" is used to classify and track action items. The matrix identifies items needing corrective action and priority ranking. A report highlighting the strengths and weakness of the facility is created from the matrix items.

Draft copies of this report and the action item matrix are provided to the company during the audit. The final audit report is prepared for company management, affording them the opportunity to address the findings and recommendations. Throughout the clearance phase of the audit, the MRMD team continues to coordinate with the operator in evaluating the adequacy of corrective actions and tracking progress of the proposed corrective actions.

This program could not be successful without the cooperation and support of the operating company. The safety audit benefits both the company and the State by reducing workplace hazards, environmental accidents, property damage, and in particular, oil spills. Previous experience shows safety assessments help increase operating effectiveness, efficiency and lowers operating cost. History has also shown that improving safety and reducing accidents makes good business sense.

1.2 Platform History:

Platform Esther is an offshore oil and gas production facility operating within the boundaries of the State of California in the Belmont Oil Field. The facility is located approximately 1.5 miles offshore of Seal Beach, California on State Oil and Gas Leases PRC 3095.1 (Parcel 16A) in thirty-eight feet of water. Esther was originally installed near Huntington Beach in 1964 and began production as a Chevron manmade island in September 1965. Esther was later converted to a platform after storm damage.

Ninety wells were drilled and initial production began in September 1965 on the manmade island. In January 1983, a winter storm struck and washed away the island and facilities, leaving only well casing above the ocean surface. Construction of the platform began in October 1984, and was completed one year later. At that time, all but the current twenty-one wells being used were plugged. In December 1988, CSLC approved the Chevron Lease assignment of Lease 3095 to Unocal. Production testing began in May of 1991 and offshore processing facilities were placed on line in late 1995.

Nuevo Energy Company of Houston, Texas purchased Platform Esther along with the majority of Unocal's California assets in April of 1996. Nuevo Energy initially retained Torch Operating Company to operate their California assets for several years before assuming operations. Plains Exploration and Production Company (PXP) assumed ownership and took over operations in May of 2004 after a merger with Nuevo Energy. PXP subsequently entered into a purchase and sales agreement with DCOR in September of 2004. The sale closed in December of 2004; however, PXP continued operating the facility until the State Lands Commission approved the lease assignment on October 20, 2005.

Platform Esther is currently owned and operated by DCOR, LLC. DCOR, LLC is a limited liability corporation with offices in Ventura, California and Dallas, Texas. DCOR is owned and controlled by Mr. William M. Templeton. DCOR owns and operates eleven offshore platforms. These include Platform Eva in state waters off Huntington Beach and Platform Edith located approximately ten miles offshore in federal waters, as well as eight other offshore platforms located in the Santa Barbara Channel.

1.3 Platform Description:

Platform Esther is a permanent, fixed base, sixty four-slot drilling and production platform. The field is currently producing approximately 570 barrels of oil per day (BOPD), 7500 barrels of water per day (BWPD), and 518 thousand cubic feet per day (MCFD) of natural gas. There are 18 active producer wells and 5 active water injection wells. At least two operating personnel per shift continually operate the platform and monitor operations. Visitors and contract personnel vary depending on platform operations and maintenance.

The primary purpose of Platform Esther is to recover and process oil and natural gas. The platform consists of two primary decks, a Mezzanine area between a portion of these two decks, two small sub decks and a lower level for boat access and diving operations. The Drill Deck is the upper primary deck, which houses the diesel crane, chemicals, maintenance equipment area, spill booms, and other equipment to support drilling and workover operations. The Production Deck is the lower primary deck and is separated into two sections by a firewall. The South side of the Production Deck houses the well bay, which includes the production and injection wellheads and their flow lines. The Production Deck also contains the process tanks, pressure vessels, and pumps. The North side of the firewall of this deck contains the control room, welding shop, electrical switchgear, motor control center, and other equipment required to support platform operations. The North and South Sub Decks, located just below the Production Deck, contain wastewater collection tanks and pumps, which are used to capture and separate hydrocarbon fluids recovered from process and gravity drains, including rainwater. The lowest level or boat access deck is referred to as the 10ft. level, and it is comprised of grated walkways enabling access to much of the platform lower structure. The 10ft. level is the deck that provides direct access to the crew boat landing area where personnel are transferred on and off the platform. The 10ft. level can also serve as an area for diving operations to allow inspection of the platform legs and under structure.

Variable speed electrical submersible pumps (ESPs) are used to produce the wells. The produced fluid is pumped directly to Gross Oil Separators V-5 and V-6, operating in parallel, where the oil, water and gas are separated. A third Gross Oil Separator (V-7) is typically used to re-run off spec oil. Oil leaving the gross separators is sales quality, and no further treatment is needed. Metered oil flows into to the shipping tank and is pumped to shore via a 3-inch oil line, which ties into Crimson Pipeline at an onshore ground vault.

Produced water from the Gross Separator flows through a series of vessels that de-oil and filter the water for injection. The first vessel is the Surge Vessel (V-201) which dampens flow surges and is the first step in removing residual oil from the water. Next is the Flotation Cell (V-202) which is fed by the Surge Tank and Flotation Cell Pumps (P-202 A/B). The Flotation Cell removes the bulk of the residual oil and some suspended solids. It operates by using an eductor-dispersion system to mix gas from the vessel headspace with the produced water. This water-gas mixture goes into the vessels riser-tub-pack where the bubbles coalesce. The bubbles form a foamy froth that is removed by periodic skimming. The water then flows to the Guard Filters (F-204 A/B), which act as polish-filters for the water. From the Guard Filters, the water enters the Pump Surge Vessel (V-206). The Pump Surge Vessel dampens flow surges and enables smooth flow control of the Produced Water Injection Pumps (P-207 A/B/C). Produced water is re-injected as part of an enhanced oil recovery system. High pressure polished filter water is injected downhole at approximately 4,500 feet as part of the water flood.

The gas collection system collects low-pressure gas from the wells as well as separated and recovered gas from the oil and water plants process vessels. Collected gas then flows to the Suction Scrubber (V-302A), which removes any fluid from the gas stream before entering the gas compressor skid. The discharge of the gas compressor is routed to the Hydrogen Sulfide Scavenger system (Hydrocat) for H_2S removal and to meet pipeline specifications. After Hydrocat processing the sales gas H_2S content is typically less than 1ppm before entering the 10-inch sales gas pipeline to shore.

Facility Condition Audit

DCOR, LLC
Platform Esther
Seal Beach

2.0 FACILITY CONDITION AUDIT

2.1 Goals and Methodology

The primary goal of the Safety and Oil Spill Prevention Audit Team was to evaluate the topside equipment and mechanical integrity of DCOR's Platform Esther offshore facilities. The audit team inspected the platform thoroughly including the safety, production, and electrical systems, and identified the regulatory requirements applicable to each. Field tasks included confirmation of accuracy of facility drawings/plans, review of testing, inspection, and equipment maintenance histories, and completing a variety of facility condition checklists. All of these tasks enable technical design review of the platform's safety systems. The audit report reflects this "system by system" process and includes a description and assessment of each system, and any significant action items or observations. Specific sections of the report may address personnel safety concerns, while others are more applicable to facility process safety. The facility condition audit is also an essential preliminary element that is later used while assessing the organization's safety management program development and implementation.

2.2 General Facility Conditions

2.2.1 Workplace Housekeeping: Platform Esther was clean and orderly. The production office is well organized and contains up to date reference materials. The platform had an adequate number of clearly marked refuse containers, and there was no noticeable debris scattered about the platform. Restrooms are located on the Production and Drilling Decks, and were found to be in good condition with no obvious health or sanitation concerns.

DCOR also uses preventive maintenance as a practice of good housekeeping to further minimize the occurrence of leaks and releases of chemicals and other materials to containment systems, or to the environment. Containment devices such as drip pans are used to help eliminate ocean contamination if a leak were to occur.

2.2.2 Stairs, Walkways, Gratings and Ladders: The majority of stairs, walkways, and gratings found on Platform Esther appear to be in good condition; however, there are steel plate flooring and walkways that are in fair to poor condition due to corrosion. Although corrosion seems to be an ongoing problem for the platform, repairs of steel plate flooring and walkways were taking place at the time of the audit. Safeguards were in place wherever there was a need to transition between levels, and for routine access to equipment. The portable ladders observed were in good condition and free from oil and grease. DCOR's safe work practices define the use and care of platform ladder equipment.

2.2.3 Escape / Emergency Egress / Exits: Escape routes, emergency egress, and exits are free and unobstructed. Safe briefing areas are shown on the Station Bill and are discussed during the platform orientation. In the event of an emergency, personnel will be directed by intercom to report to the appropriate safe briefing area based upon the location of the emergency and/or wind direction. Windsocks are located for maximum visibility and appeared to be in good condition. Emergency lighting is generally adequate throughout the platform and the illumination was satisfactory. Emergency evacuation of the platform is accomplished by crew boat although evacuation by helicopter is an option.

2.2.4 Labeling, Color Coding and Signs: The design, application, and use of signs and symbols on the platform are adequate. The signs follow Occupational Safety and Health Administration (OSHA) and American National Standards Institute (ANSI) recommendations. Fire diamonds were visible on all tanks, vessels, and chemical storage totes. The posting of fire diamonds comply with the Uniform Fire Code.

2.2.5 Security: Physical and operational security measures are in place on Platform Esther to prevent unauthorized entry. Passive and active measures protect personnel, equipment, and property against threats. The platform is manned twenty-four hours a day, seven days a week with at least two operators present at all times. There is a limited route of access from the boat landing, and there are a sufficient number of restricted access signs posted which are visible from all sides. Authorized personnel travelling to the platform must be pre-listed on an approved boat log before boarding. Ship Services deck hands check that each person's name appears on the boat log in sheet and then check for proper identification and swing rope certification. In addition, information security protects the confidentiality, integrity and availability of data from accidental or intentional misuse by people inside or outside the facility.

2.2.6 Hazardous Material Handling and Storage: The storage of flammable and combustible liquids on Platform Esther appears to conform to both Cal OSHA and National Fire Protection Association (NFPA) 30 standards. Material Safety Data Sheets (MSDS) are available for each hazardous substance on location and can be found inside the Control Room.

Chemical and diesel storage on the platform appears to be properly located, and protected against external damage and leaks. Bulk chemical totes have proper labeling and adequate containment in the event of a spill.

Compressed gas cylinders were secured and legibly marked to identify the gas content. Empty and unused cylinders had closed valves with protection caps in place. Cylinders were observed stored in places where they would not be knocked over or damaged.

2.3 Field Verification of Plans

2.3.1 Process Flow Diagrams (PFD): The PFD drawings are part of the process safety design information for the facility and indicate the general flow of plant processes and equipment. Platform Esther's PFD drawings were up-to-date and no concerns were found.

2.3.2 Piping and Instrumentation Diagrams (P&ID): Field verifications of the P&ID's were reasonably accurate; however, minor updating is required. The discrepancies in the P&ID included valve sizing and piping errors, missing equipment and out of service or removed equipment.

2.3.3 Fire Protection Drawings: Firewater / Foam Utility Flow Diagram and the Platform Station Bill were available and reviewed for accuracy. No concerns were found and the Firewater / Foam drawing is current and up to date.

2.4 Condition and Integrity of Major Systems

2.4.1 Piping: An external visual inspection of the piping systems was performed using a checklist, piping drawings and inspection records. The visual inspection noted coating failures, signs of misalignment, vibration and leakage. The evaluation also included the condition of pipe hangers and supports as well as any field changes or temporary repairs not recorded on the piping drawings. Other key information such as material selection, piping design and maintenance practices was also considered during the inspection. The piping throughout the platform was in good condition, and piping materials and components were compatible with the operating parameters and environment. However, there are some issues on the Mezzanine Deck, specifically broken or missing pipe clamps, dissimilar metals and active corrosion resulting in two Priority 3 action items. (EFI – 2.4.1.01 & 02)

DCOR uses continuing routine and risk based piping inspections to achieve a desired level of facility safety, environmental protection, and unscheduled downtime. Inspection frequencies are set up according to regulatory requirements and established guidelines, for example, American Petroleum Institute (API) Recommended Practice (RP) 570 and Department of Transportation (DOT) pipeline inspections. Unburied oil and gas piping visual inspections occur annually while subsea oil and gas pipelines are inspected annually using an electronic survey tool. Results of thickness measurements for the piping systems along with repair recommendations are stored electronically. No issues were noted. Results from thickness measurements, inspections, repairs and other tests are readily available and recorded within a database system called Microsoft Access. A maintenance management system called Mainsaver is used to generate maintenance and inspection activities.

2.4.2 Tanks: Tanks located on an offshore platform are maintained following a program of external and internal examinations based upon API RP 653. DCOR's maintenance practice follows API 653 recommendations, industry standards, and regulatory requirements. Tank documentation includes inspections, repairs, and alterations. DCOR maintenance records indicate that internal tank inspections occurred in 2010 and external tank inspections occurred in 2013. Tank shell ultrasonic thickness readings were completed for both T-7 and T-9 in 2007. The nozzles on T-9 were re-inspected in 2014; however, there was no indication that the nozzles on T-7 had been re-inspected resulting in a Priority 3 item. (EFI – 2.4.2.01)

2.4.3 Pressure Vessels: Pressure vessels are also maintained following a program of external and internal examination. The external and internal inspection intervals for all pressure vessels were reviewed for compliance with applicable regulations, recommended practices, (e.g. API RP 510 and CSLC 2132(g)(3)), and record keeping. DCOR's Mechanical Integrity Engineer tracks wall thickness, corrosion rates, inspection due dates, and predicts retirement dates for individual pressure vessels based on total metal loss and risk. Contractors perform vessel inspections (external and internal) within 5-year intervals using nondestructive examination techniques. External inspections found no evidence of leakage, distortion or cracks at welds, foundation damage, corrosion, or defects of piping connections. Internal inspection records show corrosion to be low and at a predictable rate with no major concerns, but the visual inspection did identify some minor concerns about anchoring and foundations. In addition, the records inspection found that one pressure vessel had passed its due date for re-inspection resulting in a Priority 2 action item. (EFI – 2.4.3.01) Pressure vessel records are well maintained and are easily accessible onshore.

2.4.4 Relief System: The piping for the relief vent system on Platform Esther was evaluated for condition, functionality and maintenance. The primary purpose of the pressure relief system is to ensure protection for facility personnel and equipment from overpressure conditions that may happen during process upsets, equipment failure, and external fires. The relief vent system is designed with a vent stack, flame arrestor and a scrubbing vessel to remove liquid hydrocarbons. If any of those events should occur, the vent gas system will collect and discharge any gas from the pressurized process components to the atmosphere. Vent gas exiting the system is dispersed to the atmosphere through a flame arrestor. The flame arrestor allows gas to pass through it but stops a flame in order to prevent a larger fire or explosion. The flame arrestor is inspected annually for clogging. No discrepancies were noted.

2.4.5 Electric Submersible Pumps (ESPs), Pump Units, Wellhead Equip. & Well Safety Systems: Safety devices were verified to be installed on producing wells and flow lines. Surface Safety Valves (SSVs), Flow Safety Valves (FSVs) and shutdown valves are commonly used to shutdown and isolate a line if a leak were to occur. SSVs and FSVs are tested monthly as required by CSLC regulations to ensure they function and are capable of holding pressure without leaking. No problems were noted.

2.4.6 Fire Detection Systems: Fire detection systems used on platforms are designed to alert personnel of the existence of a fire condition and to allow rapid identification of the location of the fire. The types of fire detectors used on platform Esther are:

- Smoke Detectors (19)
- Heat Detectors (3)
- UV/IR Detectors (24)
- Gas Detectors (9)

Smoke detectors protect people and property by generating an alarm early in the development of a fire while heat detectors minimize property damage by reacting to the change in temperature caused by a fire.

Smoke detectors are located in the galley, electrical office, motor control center (MCC), and in the programmable logic controller (PLC) room, telecommunications, battery, sleeping quarters, control and change rooms. Any detection of smoke or products of combustion will sound the fire alarm. In addition, smoke detectors in the MCC and PLC rooms will shutdown the platform when activated. The remainder of the smoke and heat detectors produce an audible alarm over the platform PA when activated. The platform also utilizes ultra-violet and infrared (UV/IR) flame detectors (fire eyes), which detect fires by monitoring in both the UV and IR spectral ranges. Fixed flammable gas Lower Explosive Limit (LEL) detectors continuously monitor for the presence of combustible gas and are set to detect lower explosive level concentrations at 25%, triggering an audible alarm; in addition, they will automatically activate the shut-in sequence when concentrations reach 45%. These settings more than meet the required standards of 60% and 80% respectively per MRMD 2132(g)(5)(C)(D). The UV/IR detectors found in the well bay and production area of the platform will activate the fire alarm, ESD and deluge systems.

The fire detection system is designed with bypasses to allow for testing. A MRMD inspector witnesses the flame, flammable gas and smoke detectors operation during monthly testing and records the results. In addition, facility personnel who observe a fire can activate one of Platform Esther's 15 fire alarms and/or manually initiate fire suppression before automatic sensing devices activate the deluge system. No discrepancies were noted.

2.4.7 Fire Fighting Equipment: The firewater supply is a seawater pressurized system with a jockey pump, two fire pumps, fixed monitor stations, foam system, hose reel stations, and a wellbay deluge system. The jockey pump maintains the firewater header pressure at approximately 150 psig. A 400 horsepower electrical-driven vertical shaft turbine-type firewater pump (P-8) operating on a pressure switch automatically starts if the firewater header pressure drops to 130 psig. A further drop to 110 psig. will automatically start the Caterpillar diesel-driven vertical shaft turbine-type firewater pump (P-9). While P-8 is considered the primary firewater pump, P-9 can be used in the event of a power failure. Both pumps are rated at 2500 gallons per minute at approximately 170 psig. Fire hose stations are strategically located throughout the platform and arranged to provide coverage of the target area from two different directions. The firefighting systems are installed and maintained under NFPA 20 and 25 standards per CSLC regulation 2132(g)(4). Champion Fire Systems Inc. conducted annual flow tests and passed both firewater pumps in April 30, 2014. MRMD inspectors witness weekly testing of the firewater pumps and monthly testing of the deluge system as required by MRMD regulations.

Dry chemical fire extinguishers are located strategically about the platform and comply with CSLC 2132(g)(4)(F), NFPA and OSHA regulations. Operating personnel inspect fire extinguishers monthly and annual servicing is done by a third party contractor. Cal OSHA regulations require that employees receive annual training in the use of fire extinguishers for incipient firefighting. The company provides required annual online training to familiarize employees with the general principles of fire extinguisher use and the hazards involved. The hands-on training is provided as part of DCOR's annual block training. Two Priority 2 action items were issued due to fire extinguishers missing from their assigned locations. (EFI - 2.4.7.01 & 02)

2.4.8 Combustible Gas and H_2S Detection Systems: Platform Esther is equipped with nine (9) fixed gas LEL detectors that continuously monitor for the presence of combustible gas. Platform Esther's LEL monitors trigger an audible alarm at 25% of LEL and activate shut-in sequences when concentrations reach 45% of LEL. These lower limits more than meet the required standards and provide an additional measure of safety. MRMD inspectors witness the monthly testing of the flammable gas detection system by DCOR operating personnel. The number and placement of the gas sensors on the platform appear to give adequate detection coverage.

The installation of a hydrogen sulfide (H_2S) wireless detection system became necessary in December 2015 with the rise of H_2S levels in the production stream. Although downhole chemical treatment is being used to control hydrogen sulfide levels, the MRMD was concerned that levels could rise for a variety of reasons and that MRMD regulations for H_2S should apply. The hazard prompted DCOR to install a Hydrocat to remove hydrogen sulfide from the produced gas stream. A one-year agreement between MRMD and DCOR, which runs from December 2015 to December 2016, specifies MRMD H2S regulatory requirements for compliance and additional administrative actions related to the installation of the Hydrocat. The continued operation of the Hydrocat is contingent upon its satisfactory operation and installation of additional safety devices, equipment and administrative controls. The approval process also included the installation of a dedicated H_2S warning alarm, flammable gas and additional H_2S detector, which has the ability to shut-in the sales gas line when the H_2S level reaches 15ppm. MRMD inspectors witness the monthly testing of the H_2S sensor. In addition, an action item was developed that requires completion of the conditions of approval. (EFI - 2.4.8.1)

2.4.9 Emergency Shutdown System (ESD): The platform is equipped with eight manual ESD stations that comply with CSLC 2132(g)(1)(A). Activation of an ESD will cause shut-in of all wells and pipelines as well as the complete shutdown of the production facility in the event of fire, pipeline failure or other catastrophe. This is in addition to other safety devices that have the ability to automatically shutdown the platform. The eight manual ESD stations on Platform Esther are tested monthly in bypass mode to ensure automatic shutdown systems are functioning properly. MRMD inspectors witness and record the results of the tests. During semi-annual testing, one of the manual ESD stations or process shutdowns is fully tested with an actual live test to ensure the platform will shutdown in sequence as designed. The ESD system appears fully compliant with API RP 14C. No problems were noted.

2.4.10 Safety and Personal Protective Equipment (PPE): DCOR has a written policy to provide a safe and healthy workplace, and to comply with all applicable federal and state regulations about occupational safety and health. All personnel entering a DCOR facility must at a minimum wear hard hats, safety glasses, hard toe boots, fire resistant clothing (FRC), and personal H_2S monitors on the platform. Personal Protective Equipment (PPE), such as hearing protection, face shields, rubber gloves, aprons, and fall protection that may be needed are found in the DCOR Safety Manual, Safe Work Permit or Job Safety Analysis (JSA). In addition, PPE requirements are listed in work permits and safe work practices. DCOR also uses their morning safety meeting to stress the need for safety awareness, potential job hazards, and the use of proper PPE. No issues about the use of PPE were noted while on the platform.

All first time visitors to Platform Esther must complete orientation and training at Ship Services in San Pedro. The DCOR orientation includes viewing an instructional video, answering a written quiz, and satisfactorily demonstrating their swing rope capability before travel to the platform is authorized. DCOR's PPE requirements are outlined in the training video. First-time platform visitors to Platform Esther receive a site-specific briefing upon arrival. However, one Priority 2 deficiency was to place life rafts and first aid station in the locations shown on the Equipment Location Plan. (EFI- 2.4.10.01)

2.4.11 Lighting: Platform Esther appears to have sufficient lighting to conduct safe operations throughout the platform. Mounted fixtures with high-pressure sodium vapor provide primary area lighting or similar type lighting is used. Control room and emergency lighting is tied into the emergency generator and is designed to operate if the platform loses its primary electrical supply. Additional information regarding lighting levels can be found in the electrical portion of the safety audit.

2.4.12 Instrumentation, Alarm and Paging: The process instrumentation and control has changed from pneumatic to digital through past facility upgrades. Production controls and instrumentation are now part of a Digital Control System (DCS) that is connected to the platform by digital networks. Within the DCS, PLCs are used to control and oversee all the production, process equipment and instruments on the platform and automatically shut down and isolate systems or equipment in the event process deviations exceed set points.

Operations management software (Wonderware) provides the operator interface displaying plant wide activities. The software also has the ability to detect instrument errors and equipment failure. This ability, in combination with optimizing features, makes both start up activity and operational routines much easier and more efficient for operators. Wonderware also supports information management that shows historical information which can be used to improve process efficiency and plant performance.

The platform's DCS system is effective in helping the operator in handling an emergency. All process alarms appear in three different colors and frequencies to display various priorities. Platform Esther's safety shutdown system originating functions are annunciated so operators can find out the cause of the event. A distinctive audible alarm is used to distinguish the shutdown system alarm from an ordinary process alarm. First-out alarm displays on the Human Machine Interface (HMI) use time tags to identify pre-shutdown process alarms and shutdown events allowing the operator to take corrective action before the protective system activation occurs. The alarm management and control using this arrangement avoids alarm floods and continuous alarm rates that could cause a critical alarm to go undetected. Facility alarms are tested yearly and safety shutdowns are tested monthly. Facility test results and maintenance records are easily tracked, and recovered within Mainsaver.

2.4.13 Auxiliary Generator / Prime Mover: The system is in good condition and appears to be well maintained. Platform Esther's auxiliary generator is a Caterpillar Olympian Model D30P1 Diesel Generator rated at 30kW, three-phase, and 208Y/120V standby package unit. The generator appears adequate to supply the emergency needs of the platform and supplies the emergency air compressor. The Uninterruptible Power Supply (UPS) system, platform emergency lighting, foghorn, and PLC computer screens are capable of monitoring fire detection, combustible gas, toxic gas detectors, and associated alarms. The auxiliary generator is tested weekly.

2.4.14 Spill Containment: Spill containment for Platform Esther appears to be adequate. A 6-inch lip at the bottom of the handrails traversing the entire production deck and drill deck serve as passive containment. Rainwater and spills of any process leaks are handled by deck drains that flow to two sump tanks located on two separate sub decks located beneath the Production Deck. Sump Tank (T-9) handles wellbay and process area fluid, while Sump Tank (T-7) handles Drill Deck and firewall fluids. The fluid from the sump tanks is pumped to the gross oil separators.

2.4.15 Spill Response: Platform Esther maintains 1500 feet of Series 3000 Expandi-boom, 240 feet of sorbent boom, and four bags of assorted sorbent pads to contain any spill that might get into the ocean. This boom can be deployed for initial containment in conjunction with the crew boat until Marine Spill Response Corp. (MSRC) arrives on location to assume coordination and control of remediation activities. Additional resources maintained on the platform specifically for spill response include marine radios and tracking flags. These are in addition to phone/fax lines, company radios, and Ship Services contracted crew boat. All of the equipment appears to be well maintained and is inventoried as part of the MRMD monthly safety inspection. Spill drills with boom deployment occur semi-annually in conjunction with MSRC.

DCOR is a member of a cooperative of oil producers, refiners, transporters, and shippers that provide funding to MSRC. MSRC is a national non-profit United States Coast Guard (USCG) classified Oil Spill Response Organization (OSRO) with a large inventory of vessels, equipment, and trained personnel. MSRC operates three oil spill response vessels (OSRV), two boom boats, two deployment boats, and a shallow water barge from Berth 57 at the Port of Long Beach. Boom deployment drills occur semi-annually with MSRC with the last boom deployment having occurred on October 15, 2014.

An Oil Spill Contingency Plan is required by California Department of Fish and Game, Office of Spill Prevention and Response (OSPR) regulations and a Facility Response Plan is required by federal Environmental Protection Agency (EPA) regulations. These two plans will be discussed in more detail in the Safety Management Programs Audit.

2.4.16 Cranes: Platform Esther is equipped with two cranes. The main crane is a Nautilus 380L1-100 nominally rated at 30 Tons. A smaller crane is available for light loads. DCOR has established a crane safety policy that requires a job safety analysis and a crane-lift checklist be completed prior to performing a critical lift (over 36,000 lbs.), or a blind lift where the crane operator is unable to see the item being lifted, and must rely on hand signals or radio communication from a spotter.

Cal OSHA regulations require that cranes over three-ton capacity be load tested every four years and after major repairs. R.A. Batchelor Co. of Upland, CA performed a proof load test via water bag on February 22, 2014, testing the Nautilus main line to 68,176 pounds and the whip line to 11,000 pounds. Crane inspection records (monthly, quarterly, yearly) comply with Cal OSHA 5031 requirements and API RP 2D Operation of Offshore Cranes. No deficiencies were noted.

2.5 Mechanical Integrity

This section gives a general evaluation of the maintenance program and comments on management's approach to mechanical integrity. DCOR has an acceptable strategy for equipment that is of minimal importance to operations or has low cost. Equipment designated as run-to-failure are fixed in the event of a breakdown (by repair, restoration or parts replacement) until it is more feasible to simply replace the equipment.

Preventative maintenance (PM) is another maintenance strategy employed by DCOR. The company uses a computer-based preventive maintenance program called Mainsaver to manage equipment, and to minimize the threat of oil spills and their impact on the environment. The maintenance program has the ability to schedule preventative and corrective maintenance, track work order status and record asset costs. In the past, inspection and condition monitoring of vessels, tanks and piping lacked the expertise to oversee the management of these assets. DCOR has since remedied the situation with the addition of a Mechanical Integrity Engineer. The engineer is tasked with implementing the correct maintenance strategies, done at the right frequency, to decrease the rate of failure and increase equipment reliability.

Maintenance on rotating equipment is done by company personnel while tank and vessel inspections are contracted to an outside service provider. DCOR also uses the skills and availability of employees for their Equipment Improvement Team (EIT). The team evaluates the mechanical condition of platform equipment. The team's focus is to detect the early signs of equipment decline and recommend corrective action(s).

In an exposed marine environment, corrosion is a major problem for offshore platforms both in terms of cost of equipment repair/replacement and potential pollution. Visual, ultrasonic, and other non-destructive testing is part of the corrosion monitoring of production equipment and piping. The corrosion monitoring is intended to keep the platform in good structural condition and maintain equipment in a safe working condition. Corrosion inspections are performed annually and the results are recorded. Painting program priorities are based on inspection results. However, it is unclear whether DCOR's corrosion inspections are being followed up with corrective action. DCOR's painting program appears to be ineffective or non-existent, and the platform seems as if there has been no significant blasting and painting in many years. (EFI – 2.5.01)

The physical condition of the platform varied significantly from good to fair. The platform shows several common modes of coating failure that have led to corrosion. Common areas and causes of coating failures observed on the platform include:

- Beam Edges
- Fasteners
- Pipe Supports
- Mechanical Damage

Due to the condition of platform paint coatings, and corrosion, CSLC recommends DCOR use this opportunity to evaluate the effectiveness of their Corrosion Control Program. The program should have management's commitment, and place emphasis on monitoring and evaluation of control measures. In addition, all operating personnel should be provided with appropriate training to enable effective identification of corrosion that may be of concern.

2.6 Production Safety Systems

DCOR's production platform process equipment and pipelines are designed, installed, and maintained in a manner that provides for safety of operation, and protection of the environment. Platform Esther's production facility is protected with basic and secondary surface safety systems designed, tested, and maintained in accordance with MRMD Regulations and API RP 14C.

Safety Analysis Function Evaluation (SAFE) charts are used to verify the design and installation of safety systems as required in API RP 14C. SAFE charts are used to ensure that the facility is as fully protected as it should be and can be used as a troubleshooting tool. The SAFE chart provided a means of verifying the design logic of the basic safety system. All safety devices and their functions were analyzed by comparing the SAFE chart to facility piping and instrumentation diagram/drawings. The comparisons matched all safety and shutdown devices, as well as, emergency support systems (ESS) to their functions. The review of SAFE chart logic found all devices were related to their functions and a proper level of protection is being maintained. The review also found the design of the platform safety system to be fully compliant with API RP 14C. The SAFE chart appeared to be current with three minor exceptions, which included incorrect Safety Analysis Checklist (SAC) references, mislabeled equipment, and a number of safety devices in the SAFE chart did not match the P&IDs. (TEC – 2.6.01, 02 & 03)

All platform wellheads SSV's are inspected, installed, and tested in accordance with CSLC 2132(a)(9)(A) & (D) and API RP 14C. Surface safety valves found on wells will automatically close to isolate the well and prevent oil and gas from escaping into the environment. Any SSV that does not operate properly or if fluid flow is observed during the leakage test, is either repaired or replaced.

Extensive coverage of fire and safety systems is installed throughout the platform. Included in these systems are safety devices that automatically shutdown oil and gas production if an emergency occurs. Every operator/contractor on the platform is authorized to shutdown the platform should they detect an unsafe condition. As part of the surface production safety system, valves are used to isolate the various process systems and lessen the environmental impact should any system problem be identified. Should evacuation be necessary, platform personnel have several choices ranging from helicopter, crew boat, and life rafts.

Process Hazards Analyses (PHAs) are performed as part of the Management of Change (MOC) process and before any construction can begin on a new project. This systematic approach for identifying, evaluating, and controlling the hazards of the process helps build-in additional safe guards and can help evaluate the contribution of each safety device or system protection. When hazards cannot be removed or controlled through design, DCOR uses a hierarchy of health and safety controls (e.g., Administrative and Engineering Controls) to eliminate hazards or reduce exposure to hazards.

The Human Machine Interface computer helps the operator manage and understand the status of the process control, and the safety systems. The HMI provides a graphics-based visualization of the platform control and monitoring system. The user interface resides in a Microsoft Office-based Windows computer that communicates with a PLC for specific functions, along with the Digital Control System on the platform. This equipment allows operators to control the process within authorized parameters. Uniformity in process settings among the different operating crews is carried out through a strict safety systems procedure that restricts operator access to the program control code. Separation of safety-related functions from process control reduces the risk of common cause failures and assures the safety system will function properly. Bypass switches for functional testing provide "no interruption" to the normal process operation. System safety integrity is maintained when a device is placed in bypass by procedures, and the use of an alarm to signal an active bypass. Additionally, facility controls and safety features are designed to be fail-safe, and have redundant capacities.

Electrical System Audit

DCOR, LLC
Platform Esther
Seal Beach

3.0 ELECTRICAL AUDIT

3.1 Goals and Methodology

The primary goal of the Electrical Team (ELC) was to evaluate the electrical systems and operations at DCOR offshore Platform Esther to determine conformance to the California Electric Code (CEC) and industry standards.

References used in review of facilities include documents published by the American Petroleum Institute (API), National Fire Prevention Association (NFPA), the State of California Electric Code (CEC) and California State Lands Commission Regulations. The ELC Team review comments are primarily based on publications, which primarily include API RP 14F, API RP 500, API RP 540, CEC documents, and industry standards. The drawings used in support of the audit were Electrical Single-lines and Area Classification Drawings provided by DCOR for Platform Esther.

Specific tasks to accomplish this goal included a systematic process of field verification of electrical single-line diagrams, plan drawings, area classification drawings, and operation and maintenance practices. A comprehensive use of inspection checklists, code and standard compliance checklists, and review of electrical system design for conformance to codes and standards was utilized to complete the audit. This report includes a summary of the electrical systems included in the audit.

The ELC Matrix, Section 3.0, provides a detailed listing of the locations and items identified for correction. The matrix is organized in sections. Each section is discussed below along with examples of typical items encountered.

3.2 Hazardous Area Electric Classification Drawings

The API recommended practices and CEC requirements provide specific guidelines for the electrical classification of hazardous areas and installation practices for electrical equipment and materials within classified areas. Areas that contain, or may contain, flammable gases and vapors in normal operations can form an explosive environment that is ignitable by hot surfaces, electrical arcs, and sparks. To prevent this from happening, facilities are classified according to the hazard present in the different areas. This is done so all electrical equipment and systems are properly selected and installed. The basis for observations and review comments for all hazardous areas are API RP 500, CEC 500, 501, and 504 as well as API RP 14F. The hazardous area electrical classification diagrams are generally representative of the existing conditions and area class elements. The drawings need to be updated on a regular basis as process and equipment additions and deletions are made. However, the drawings do need to be updated to include process and equipment additions, and deletions made since the last revision in 2009. (ELC - 3.2.01, 02 & 04)

The purpose of an Electrical Area Classification Drawing is to define the locations of boundaries and areas where specific electrical installation practices are required to manage the explosive properties of flammable liquids, vapors, and other volatile materials. Installation and maintenance of electrical systems requires attention to the type of hazard and the level of the hazard in order to insure compliance with the CEC. Electrical Area Classification Drawings are required to contain the information necessary for a qualified electrician to perform work in, and around classified areas. DCOR drawings DCOR-ES-PL-D-0341, 0342, and 0343 were last revised in October 2009 and require a revision.

The addition, relocation or change in process equipment, lines and valves requires that classified areas be reassessed, and that classified boundaries be redrawn. If the Area Classification Drawings in some cases do not show the present conditions, all new electrical equipment purchased for installation should meet the most stringent requirements and be rated explosion-proof in accordance with the Code. The area classification drawings, as presented, do not show permanent equipment to scale or in plan. (ELC - 3.2.06) The drawings should be updated to show equipment similar to the Equipment Location Plan.

Portable chemical tanks are used for fluid treatment and are located throughout the platform. The tanks are portable, but the locations of the tank installations are, by definition, permanent and include meter pumps, which operate continuously. Many of the portable tanks contain flammable liquids but none of the areas where such tanks are in use appear on the Area Classification Drawings. The lines, pumps, and fittings associated with the tanks containing flammable liquids are also a source of hazard, and require classification of the areas affected. Show all totes on the area classification plans. (ELC - 3.2.05)

General-purpose electrical equipment (switches, light fixtures, control panels, etc.) is, in general, not suitable for installation in hazardous locations in classified areas. Electrical equipment that is not suitable for installation in a classified area will need to be relocated, replaced with equipment that is suitable, purged, or non-permeable barriers will need to be installed. After updating and revising the area classification boundaries as required by the matrix, and as described below, additional equipment may be identified as unsuitable. Enclosed and gasketed fittings are suitable for Division 2, but not Division 1. National Electrical Manufacturers Association (NEMA) 3R enclosures are suitable for unclassified areas but not Division 1 or Division 2. Where NEMA 3R enclosures are located in Class I areas they are required to be purged and pressurized per NFPA 496. All pressurized enclosures and buildings were found to have adequate positive pressures during the site visit.

<u>Drill Deck:</u> Area classification plan drawing, DCOR-ES-EL-D-0341, was received for the drill deck. The drawing appeared to adequately show the latest permanent equipment locations and the extent of area classification for the permanent installation. However, several new permanent additions such as 12kV transformer TX-D, the new Living Quarters, and the repurposed Office and Galley need to be added to the plan. The plan was last issued in October 2009. (ELC - 3.2.06)

<u>Production Deck:</u> The production deck area classification plan drawing, DCOR-ES-EL-D-0342 was last issued in October 2009 and does not reflect the latest equipment locations or extent of classification. The following items should be included on the drawing; location of the new Cut Lab skid and removal of E-401. (ELC - 3.2.02 & 04)

<u>Sub Deck:</u> Area classification plan drawing DCOR-ES-EL-D-0343 was received for the sub deck, and is complete and up to date.

<u>Platform Elevation:</u> No area classification showing the vertical extent of hazard of the platform was received. A section cut through the drilling area and well bay (all decks) showing

the extent of hazard during drilling operations is needed. (ELC - 3.2.07) Extent should be in accordance with API RP 500, Figures 67 through 70 as applicable.

3.3 Electrical Power Distribution System, Normal Power

3.3.1 Electrical Single-Line: The single-line drawings received for use and reference during the assessment are dated April 28, 2015 and are generally representative of the electrical power system. The single-line diagrams were created for use to complete the recent Arc Flash Study. It is recommended that the single-lines be revised to include missing information, device and circuit identification that matches field installed labeling, and additional system information needed for engineering purposes. (ELC - 3.3.1.01, 02 & 07)

3.3.2 Electrical Service Capacity: The Platform normal power system capacity appears adequate based on present usage. Overcurrent protection and wire sizes were found to be appropriate. The application of overcurrent devices with respect to equipment ratings is generally satisfactory. It is recommended that DCOR confer with Southern California Edison (SCE) to establish the SCE service capacity limit, and any other limitations such as motor inrush and number of motor starts per day. (ELC - 3.3.2.01)

3.3.3 Electrical System Design Power: Electric utility service is supplied by Edison at 12kV via submarine cable from shore (Edison Building). The service location is at the Edison 1st Street facility. The Edison disconnect supplies power to Platform Esther via 1-3/C #500kcmil 15kV cable routed in below grade conduit to an on-shore vault, and then by submarine cable to the platform.

The submarine cable to Platform Esther supplies 12kV electrical power to the main Switchboard (MSW-1). This switchboard lineup consists of a one main non-fused disconnect switch for the 12kV supply, and three fused disconnect switch positions supplying transformers on the platform as follows:

- The first fused disconnect position feeds a 3750/4200kVA; 12kV-2400V transformer (TX-1) located above the switchgear room and used to supply power to the operating platform main 2.4kV switchgear (MSW-2 and MSW-3).

- The second fused disconnect position supplies the first position of a three-position SF6 sectionalizing switch (MSW-4) located above the switchgear room. The SF6 switch position 2 is a 600-amp rated RFI (resettable fault interrupter) that feeds the 2500/2800kVA, 12kV-480V transformer (TX-2) located above the switchgear room and is used to supply power to the 480V motor control center lineup (MCC-1) in the main switchgear room. SF6 switch position 3 in a 600-amp RFI that supplies power to the 3000/3750kVA Rig transformer (TX-D).

- The third fused disconnect position is connected to a 1000/1120kVA, 12kV-480/277V transformer (TX-3) located at the southeast corner of the production deck.

Nameplate descriptions on the 12kV main switchboard (MWS-1) are not prominent and do not clearly identify each load. Provide prominent nameplates that clearly identify the downstream equipment supplied from switchboard. (ELC - 3.3.3.03)

During the assessment, it was noted that the bus voltage at switchboard PCH was as low as 464V. It is recommended that DCOR monitor the bus voltage at the 240V, 480V, and 208V busses to determine if any transformer tap setting adjustment is warranted. (ELC - 3.3.3.01)

The two (2) 250kW Micro-Turbines installed on the Drilling Deck are out-of-service. When originally installed, SCE required Rule 21 interconnection protection. It is recommended that DCOR review the status of the Micro-Turbines and determine if they should be removed. If the Micro-Turbines are removed, the Rule 21 protection should be removed and SCE service interconnection agreement should be replaced with a standard power purchase contract. (ELC - 3.3.3.02)

3.4 Electrical Power Equipment Condition and Functionality

3.4.1 Equipment Condition: Given the harsh marine environmental conditions, the overall condition of electrical equipment is good. Several locations where conduit supports were rusted or otherwise inadequate are noted in the Matrix. A few missing covers, broken and missing supports, rusted enclosures, deteriorated weatherproof gaskets and missing bolts occur to a small extent throughout the facilities. (ELC - 3.4.1.01 & 02)

3.4.2 Equipment Maintenance Practices: Section 4.04 of the California Code of Regulations (CCR) Safety Standards Document covers the lockout/tagout program. The scope, responsibility, and procedures outlined in the document appear to be adequate and complete.

Arc flash hazard labeling and Personal Protective Equipment (PPE) requirements are currently being updated by DCOR. Arc Flash labels will need to be installed on electrical equipment once the Arc Flash Hazard Assessment is finalized. (ELC - 3.4.2.01)

Relay Test Labels on the 12kV and 2.4kV Switchgear breakers indicate that this equipment was last tested in July 2014. NFPA 70B maintenance and testing of equipment is recommended to be performed every three years. The next maintenance and inspection is due in 2017. It is recommended that DCOR utilize their database software program, Mainsaver, to schedule and track maintenance activity. (ELC - 3.4.2.02)

Platform personnel and contractors were not implementing an extension cord and portable equipment test program. CEC 590 identifies maximum time constraint of 90 days for temporary installations. No methodology was found in the DCOR literature to test, track, or verify that temporary and portable extension cords meet CEC 590. It is recommended that DCOR set up a testing schedule (quarterly, every 90 days), marking system for temporary power extension cords, and a method to identify when cords were last inspected for safety. (ELC - 3.4.2.03)

Electrical equipment instruction manuals should be available on the platform. Several manuals were available, but many are missing. (ELC - 3.4.2.04) In addition to maintenance manuals, the wiring schematics and diagrams are needed for troubleshooting, and for reference for use in design. Electrical schematics and wiring diagrams for all equipment utilizing wired controls should be available on the platform. (ELC - 3.4.2.05)

The electrical equipment maintenance testing completed in July 2014 identified several items requiring retest or repair. The insulating oil in TX-1 and TX-2 is out-of-limits for dissolved combustible gas and requires a retest. (ELC - 3.4.2.06) Several circuit breakers and other devices were identified as requiring replacement and repair. (ELC - 3.4.2.07) The transformer secondary neutral grounding resistor (NGR) for TX-1 requires repairs, and both of the NGR's for TX-1 and TX-2 required cleaning to remove accumulated bird dung. (ELC - 3.4.2.08)

3.5 Grounding

CEC Article 250 provides the rules for power system grounding and bonding. The requirements for grounding are established to prevent or reduce the possibility of personnel injury due to shock hazards resulting from elevated touch potential as a result of improper grounding. Three specific types of grounding are required at the facilities; power system grounding, safety or equipment grounding, and static grounding.

System grounding is as follows:

- Transformer TX-1, 12kV-2.4kV, 3-phase, 4-wire is resistance grounded through a 400A, 10-Sec resistor.

- Transformer TX-2, 12kV-480V is high resistance grounded 5-Amp, with ground indication and alarm on the MCC-1 main switchgear room.

- Transformer TX-3, 12kV-480V is solidly grounded at the Auxiliary MCC building.

- Transformers TX-4 and TX-5 located above the main switchgear room and the 15kV transformer in the Auxiliary MCC building provide separately derived systems, for 208Y/120 Volt equipment. These transformers are solidly grounded and satisfy Code requirements for power system grounding.

- TX-D Drill Deck

Article 501-16, Bonding in Class I areas, states that all non-current carrying metal parts and enclosures associated with electrical components shall be connected together, bonded, and be continuous between the Class I area equipment and the supply system ground. Bonding shall provide reliable grounding continuity from the load back to the power transformer grounding. The best way to achieve this is to include properly sized equipment grounding conductors with each set of power conductors from the source of power to each of the equipment grounding points and include bonding jumpers at points of discontinuity along the route. Equipment grounding conductors are not installed on all circuits, and bonding is achieved through continuity of raceways and fittings. Equipment bonding conductors to major equipment; transformers, switchgear and the like, were installed and appeared adequate. The aluminum cable tray above the MCC Room and at PCH is missing ground bonding jumpers. (ELC - 3.5.01)

CEC 501-16(b) requires that all liquid-tight conduit used in a hazardous area be supplemented with either an internal or external ground bonding jumper. In the past flex, conduits that have bonding included were identified with a distinctive green mark painted on the conduit. Spot check of the marked conduits confirmed bonding. Some unmarked liquid-tight flexible conduits were spot-checked and the required bonding conductors found missing. (ELC - 3.5.02, & 03)

3.6 Emergency Electrical Power

3.6.1 System Configuration: An existing 30kW, three-phase, 208Y/120V standby package generator is installed for operation in the event of a utility power outage. The generator supplies emergency panel “TS-1” through a 150-amp auto-transfer-switch (ATS). Emergency Panel “TS-1” supplies the following:

- 10-hp emergency air compressor (C-3)
- MCC room purge fan
- 20kVA UPS unit

The UPS provides ride-through to maintain critical control and communications systems during the period while the backup generator is started and transfer initiated. The MGE UPS unit feeds a dedicated UPS panel to Panel UPS-DP-1 and maintains power for the emergency systems listed below:

- Control Room computers and equipment
- General Alarm and Shutdown systems
- Modicon PLCs and I/Os for process control and monitoring
- Communications and public address system, phone
- Fire eyes and gas detection systems
- Navigation lights and foghorn
- Emergency egress lighting; control room, well bay, MCC-1
- Remote Terminal Units (RTUs), both Chevron RTU #1and LACT RTU #2
- Fire pump charger
- GC 300 PLC Flare

3.6.2 Equipment and Component Ratings: MRMD regulation 2132(g)(7) requires “an auxiliary electrical power supply shall be installed to provide sufficient emergency power for all the equipment required to maintain safety of operation in the event the primary electric power fails”. The packaged generator appears adequate to supply the present emergency needs of the platform.

The packaged generator complete with base fuel tank and weather enclosure is located in an unclassified area on the Drill Deck and is easily accessible for maintenance and testing. The generator is tested every month and records kept. The generator battery was last replaced in 2008. It is recommended the battery be tested or replaced. (ELC - 3.6.02)

UPS power is provided from a 20kW unit in the main switchgear room. The MGE EPS3 UPS is a packaged unit complete with bypass and batteries in a common cabinet and has full load battery capacity in excess of 4 hours.

3.6.3 Electrical System Design Safety: Critical systems are supplied from the backup generator and emergency UPS system. The UPS system is fed from panel board EM-DP-1 but does not appear on the single line diagram. We recommend the UPS connection to panel

EM-DP-1 be shown on the single-line drawing to make clear the supply feed to the critical systems. (ELC - 3.6.01)

3.7 Electric Fire Pump System

A 400hp electric firewater pump (P-8) is located on the Production Deck and fed by the normal power system from switchboard MSW-3 at 2,400V. The electric firewater pump provides the primary system for fire suppression.

A diesel driven fire pump is also available in the event of a system power failure. The diesel is equipped with a pneumatic (air driven) starter. A 10hp emergency air compressor, C-3 supplied from the backup power system (generator), is used to maintain starting air for the diesel fire pump should utility power not be available.

The fire protection / deluge system is a wet system with water pressure maintained by the firewater jockey pump during normal operations. The fire alarm pushbuttons do not activate the firewater pump. Instead, loss of pressure in the deluge system starts the electric fire pump. Further loss of pressure will start the diesel driven fire pump. The deluge system is tested regularly.

3.8 Process Instrumentation

The process control system uses a combination of pneumatic, hydraulic, and electrical instruments and controls. It includes the use of computers, PLC's, and relay logic to control and interface with valves, solenoids and pump controllers. Alarms are produced by level, temperature, pressure and flow sensors advising operators of process conditions. A number of instruments are outdated, but are in the process of being replaced by modern equivalents.

Two redundant Personal Computers (PCs) with the Central Processing Units (CPUs) located in the communications room and the monitors located in the control room provide operator interface to the process control system. There is also a backup PC located in the Auxiliary MCC room. The PCs are linked via modbus+ and run on the Wonderware software package.

Programming for the PLC is resident on the PLC. In the event of a PLC processor failure, backups of the latest programming are also stored on the company server located in the Communications Room. The main electrical switchgear room houses two PLCs that monitor the Lease Automatic Custody Transfer (LACT) units. No formal procedure to track changes, backups or backup frequency of the logic was available during the inspection. It is recommended that a written procedure be developed and available to operating personnel detailing PLC program backup and restoration procedures. (ELC - 3.8.01)

Two other monitors, one located in the Aux MCC room and the other in the crew galley allow remote monitoring (mimic) of the system.

The Allen Bradley PLC located in the control board CP-1 in the control room is connected via Modicon S908 data highway to five I/O drops, two located within CP-1 and three in panels in the Aux MCC building. These affectively monitor and control operations on the platform. Control and monitoring from shore are provided through the spread spectrum radio system from the RTU on platform Esther to an RTU located at the 1st Street, Seal Beach facility.

3.9 Lighting Systems

Fixtures are installed in conformance with the National Electrical Code (NEC) and appear to be located to provide adequate lighting levels for the tasks performed. Fixtures are appropriate types and designs for the environmental and hazardous area conditions.

The emergency lighting is powered from the UPS Panel, which receives power from the UPS with backup from the emergency generator in the event of extended main power failure. Review of the layout and location of emergency light fixtures indicates adequate provisions for the purpose of safe egress. (ELC - 3.9.01)

Since the platform operates around the clock, seven days a week, operators and maintenance personnel may need to perform work during nighttime hours. DCOR indicated that personnel working at night carry flashlights, and temporary lighting equipment is available for planned maintenance and larger tasks.

3.10 Special Systems (Offshore)

Special system requirements for offshore production facilities are described in API RP 14F. The ELC Team review comments for special systems are based on API RP 14F, API RP 540, and CEC documents.

3.10.1 Safety Control Systems: Safety control systems are required to be a combination of devices arranged to safely affect platform shutdown. Electrical safety control systems are normally operated energized and fail-safe. Failure of external power to a safety control circuit requires an audible or visual alarm to be initiated or operation of equipment in a fail-safe condition.

Emergency Shutdown Stations (ESD) are located throughout the platform. The stations appeared to be in good working order. Locations include:

- Drill Deck - South stair near heliport
- Production Deck; at North, East and South Stair
- Production Deck – Control panel CP-1 and Control Room entrance
- South Stair between Production and Rig Deck

Stations are hard wired to the control panel CP-1 in the control room. In addition, the flame detection system will activate an ESD automatically if flames are detected in the well bay or production areas. Relays in panel CP-1 are fail-safe type.

Fire and Abandon Platform Alarm Stations (FA) are located about the platform. All stations appeared to be in good working order. Emergency stations have plastic identification labels (Fire - white letters with red background, Abandon Platform – red letters on white background). Stations are generally mounted on red painted supports. ESD and EA stations are tested monthly and records are maintained.

3.10.2 Gas Detection Systems: Hazardous and flammable gas detection systems, (e.g., LEL and H_2S) are installed to warn about the presence of hazardous and flammable gases in unacceptable concentrations in order to prevent major accidents. Gas detectors are permanently installed in strategic locations around the platform. Platform Esther has Lower Explosive Limit (LEL) detectors (9) and Hydrogen Sulfide (H_2S) detection (1). The toxic gas detector is located below the Hydrocat while the gas detector elements (GDEs) are located on the Production Deck as follows:

- Between columns C5 & D5 (above and west of V301)
- Between columns C4 & D4 (above and west of V-5)
- Between columns C3 & D3 (above and southwest of V-7)
- Between columns C2 & D2 (above and southwest of V-203)
- Between columns C6 and B7 (above vapor recovery unit)
- Above vessels V-1 & V-2
- Above vessel V-9
- Above GC-300 compressor skid
- Below the Hydrocat

Detectors are hard wired to the Rexnord model 8000 unit in the control room panel CP-1. Detectors are located about 15-feet high in the structure over the equipment. Gas detectors and monitor are tested monthly and records are maintained.

3.10.3 Fire Detection Systems: Fire detection and smoke detection are usually employed to detect and warn personnel of fire and smoke conditions, and to initiate remedial action.

Fire-eye type Ultraviolet Infrared (UV/IR) detectors are provided on Platform Esther around the well bay, production area and mezzanine of the Production Deck along with selected tankage areas of the sub deck. Fire-eye detectors in the well bay have been relocated from column line C facing out to column line D facing in. This was done to reduce nuisance alarms caused by foreign sources (i.e. distant welding, flash photography, etc.) external to the platform.

Fire-eye signals are returned to the DET-TRONICS Fire Detection Modules in the control room panel CP-1. Fire detectors are tested monthly and records are maintained.

Stand-alone smoke detectors are provided on the ceilings of the control room, locker rooms, galley, telecom and electrical rooms throughout the platform. Units appear to be active, but were not tested during the inspection.

3.10.4 Aids to Navigation: The US Coast Guard no longer requires aids to navigation for Platform Esther. The beacons have been removed.

3.10.5 Communication: Communications systems are established to provide for normal and emergency operations. Systems used for emergency communication should have battery-operated supplies good for at least four hours continuous operation as required by API RP 14F. A UPS capable of providing power for four hours supplies the communications equipment. Communications equipment is located in the telecom room adjacent to the control room.

Incoming Service: Verizon phone service is connected through a Fiber Optic (FO) line that is included within the incoming 34.5kV power submarine cable from onshore Ft. Apache facility to offshore Platform Eva. At Eva, the fiber optic cable is separated from the power cables at the main interrupter switchgear, which is located in the switchgear room and routed through a FO/Ethernet converter to the platform Ethernet. A spread spectrum radio system links the telecom system at Platform Eva to Platform Esther. Communications equipment on Esther is powered through the UPS unit.

A radio base station in the telecom room with a remote terminal in the control room provides radio communication with the crew boat.

3.10.6 General Alarms: General Alarms shall be audible in all parts of the facility to notify personnel to abandon the facility or respond to an emergency. Red lights can be used in conjunction with the audible alarms. All General Alarm sounding devices shall be identified by a sign at each device in red letters at least one inch high describing required personnel response. Audible alarms and communication announcements could be heard throughout the platform at all locations tested.

3.10.7 Cathodic Protection: No cathodic protection rectifier system is installed on the platform. Platform corrosion control is provided through sacrificial anodes, paints, coatings, and continued monitoring by personnel, and maintenance of equipment and structures.

The production pipeline receives its protection against corrosion from facilities based on shore. The production pipeline consists of a double-wall construction with high-pressure interior tubing and low-pressure outer casing for leak detection. An increase in pressure in the outer pipe would indicate a product line leak, while a decrease in pressure indicates outer casing leak.

Safety Management Programs Audit

DCOR, LLC
Platform Esther
Seal Beach

4.0 SAFETY MANAGEMENT PROGRAMS AUDIT

4.1 Goals and Methodology

The goal of the safety management programs audit was to verify that DCOR uses an organized and systematic effort to identify and analyze the significance of potential hazards in the workplace to manage hazards and reduce the frequency and severity of undesirable events. DCOR's safety management programs are composed of organizational and operational procedures, design management, audit programs, and other methods defined by OSHA and the Environmental Protection Agency. The audit started with the review of the operating manuals, emergency and spill response plans, training programs, and other key elements. These areas were reviewed before evaluating the other programs that are addressed in their Safety and Environmental Management Program for Platform Esther.

4.2 Operations Manual

DCOR's operating manual and procedures are current with no concerns noted. The content and arrangement of Platform Esther Operations/Procedures Manuals comply with MRMD Regulation 2175 and are approved by DCOR's management. They are available in hardcopy and electronic format. The manuals are written in a short, step-by-step, easy to read format by staff that are well versed in the subject matter or have worked the process. They also have sufficient detail so that personnel with limited experience with or knowledge of the procedure can repeat the procedure unsupervised. Operations validate the procedures contained within the manual before finalization. Whenever procedures are changed or added, the manuals are updated and reapproved.

DCOR operating manual and procedures also provide specific directives on what steps are to be taken or followed in carrying out procedures. They also include instructions on how to handle upset conditions as well as what operating personnel are to do in emergencies. For example, the operating procedures addressing operating parameters will contain operating instructions about pressure limits, temperature ranges, flow rates, what to do when an upset condition occurs, what alarms and instruments are pertinent if an upset condition occurs, and other topics. Another example of using operating instructions to properly implement operating procedures is in starting up or shutting down the platform.

4.3 Spill Response Plans

DCOR developed the Oil Spill Response Plan (OSRP) to satisfy Federal and State Facility Response Plan requirements. The plan seeks to prevent discharges of oil into navigable waters and lessen the environment impact of a spill. An electronic version of DCOR's OSRP Volume 1-Core and Volume 2-Supplemental, Santa Barbara Channel and San Pedro Channel, Platforms, Onshore Facilities, and Associated Pipelines dated June 2012 (Revision 8-14) was reviewed as part of the Platform Esther audit. The document defines specific procedures and plans for responding to spill scenarios for Platform Esther and associated pipelines.

The document also includes a current copy of the California Certificate of Financial Responsibility (COFR) and provides for an incident command system. Communication plans and protection strategies are likewise described in the plan. The contingency plan moreover identifies and ensures by contract the availability of personnel and equipment necessary to respond to all contingency plan requirements, as required by the California Department of Fish and Game, Office of Spill Prevention and Response (OSPR) regulations, CCR Title 14, Regulation 817.02. The following elements are addressed within the plan:

- Incident Command Organization
- Facility description
- Hazards Evaluation Study and potential worst case spill scenario evaluation
- On-water containment and recovery procedures
- Shoreline protection and clean-up
- Wildlife Care and Rehabilitation procedures
- Response procedures

The plan was found to adequately address the policies and procedures to prevent, evaluate, contain, mitigate, and review the effects of unauthorized discharges. DCOR operating personnel are familiar with name, contact person, and telephone numbers of the spill response organization.

4.3.1 EPA Spill Prevention Control and Countermeasure (SPCC): The SPCC Plan is an Environmental Protection Agency (EPA) requirement. An electronic version of the SPCC Plan was reviewed for EPA Rule compliance. The plan is prepared following good engineering practices and provides operation, maintenance, and management strategies to lessen the potential of a spill or release of oil products. A licensed professional engineer and company management has approved the SPCC Plan. No action items were identified for this plan.

4.4 Training and Drills

DCOR has a comprehensive primary training program for new employees and continuing training that includes optional and compulsory training for all personnel. Annual training in hazard communication, incipient firefighting, personal protective equipment (PPE), Control of Hazardous Energy (Lockout/Tagout), confined spaces, hot work, respiratory protection, hydrogen sulfide, and first aid and CPR is conducted to satisfy Cal OSHA safety and health training requirements.

Facility operations' training consists of on-site facility instruction. Operators are trained on the operation of the facility and safe work practices for the process. The on-the-job training process is an on the job and evaluation method. Both the lead operator and operations supervisor must sign off on the training and qualification. Next level promotion is based on progression through these operating requirement elements. Successful completion of the elements and a field competency demonstration is required before advancement to the next level can occur. Situational awareness training helps employees recognize abnormal operating conditions as well as what to do if an abnormal event occurs. A computer based training matrix tracks all training activities and is used to alert management and individual personnel of training requirements. All DCOR operating personnel receive Production Safety Systems (T-2) Training online through Petro Skills. The course is designed to certify personnel working on offshore production platforms to operate, repair and maintain facilities and safety devices in accordance with the requirements described in Code of Federal Regulations (30 CFR 250), the Bureau of Safety and Environmental Enforcement (BSEE).

Compulsory OSHA and spill response training is also provided. DCOR conducts annual training to satisfy Cal OSHA training requirements. This training consists of classroom instruction, field briefings, tabletop, and equipment deployment drills. Drills, exercises, and safety meetings are conducted on a regular schedule. Exercises, safety meetings, evacuation, and environmental training are held throughout the year. Spill response team members are trained in facility spill plan procedures. Exercises range from tabletop discussions to actual deployment of equipment and mobilization of staff. Most spill drills are unannounced, and personnel are given a scenario, which they must respond to accomplish. After the drill is complete, personnel review their actions to determine what worked well and if any improvements are necessary. If DCOR finds any significant deficiencies in the spill plan after a drill or exercise, the company will record the deficiencies and require changes to the plan. Plan revisions may require additional inspections, drills, and training.

Platform Esther personnel conduct morning safety meetings that include all persons performing work on the platform for both general and topic specific safety subjects. Training and pre-job safety meetings are recorded and document retained. The audit team has observed that Platform Esther personnel recognize the importance of proper PPE and that the requirements are enforced. There were no action items identified regarding these safety elements.

4.5 Safety Management Programs

DCOR's safety management strategy is clearly understood and followed by all managers and employees. The policies and processes are part of an established business strategy and commitment towards continuous improvement. This commitment also requires compliance with safety, health, environmental rules and regulations. Management sets objectives for the organization to follow and the program's success can be related to a reduction of spills and employee injuries. Hazards are identified, evaluated, controlled and managed so that employees, contractors, the public and the environment are protected.

DCOR uses a Behavior Based Safety (BBS) program, which uses a bottom-up approach (focusing on field employees), with top-down support from health and safety management. The safety program promotes interventions that are people-focused and incorporate one-to-one observations (JSA Cards) of employees performing routine work tasks. Timely feedback on safety-related behavior, in the form of coaching and mentoring is also part of the safety program. The BBS process is a proactive approach that encourages employees and contractors to identify hazards and the potential for accidents, in addition to assessing their own behavior as safe or unsafe. DCOR also relies on health and safety training, safety signs, job safety analysis, hazard control, and employee participation (safety meetings) to motivate safe behavior. Employee observations are reviewed and the frequency count of safe and at risk behaviors are tracked by management.

Assessment and feedback about DCOR's safety management programs can be found in CSLC's Safety Assessment of Management Systems (SAMS), which will be conducted following this safety audit. The SAMS also provides significant benefits about human factors observations and assessments, which are described in the next section of this report. The SAMS is a separate effort from this safety audit and results are kept confidential between CSLC and the operating company.

Human Factors Audit

DCOR, LLC
Platform Esther
Seal Beach

5.0 HUMAN FACTORS AUDIT

5.1 Goals of the Human Factors Audit

The primary goal of the Human Factors Audit is to evaluate the operating company's human and organizational factors by using the Safety Assessment of Management Systems (SAMS) interview process. The California State Lands Commission (CSLC) SAMS Team conducted interviews with a cross-section of company and contractor personnel, from which an assessment of the level of Safety Management Program integration and level of maturity of safety culture is derived. The SAMS was conducted following the safety and spill prevention field review of DCOR's Platform Esther and other facilities. Interview results are considered confidential between CSLC and DCOR and are contained in a separate report.

SAMS was developed under the sponsorship of government agencies and oil companies from the United States, Canada, and the United Kingdom to assess organizational factors, enabling companies to reduce organizational errors, reduce the risk of environmental accidents, and increase safety. The assessment was divided into nine major categories to examine the following areas (The number of sub-categories or areas of assessment for each category are included in parentheses.):

- Management and Organizational Issues (9)
- Hazards Analysis (9)
- Management of Change (8)
- Operating Procedures (7)
- Safe Work Practices (5)
- Training and Selection (14)
- Mechanical Integrity (12)
- Emergency Response (8)
- Investigation and Audit (9)

Assessment of each of the sub-categories is derived from one main question with a number of associated and detailed questions to help better define the issues.

The SAMS process is not intended to generate a list of action items. Rather it provides the company with a confidential assessment of where it stands in developing and implementing its safety culture and a benchmark for future assessments.

5.2 Human Factors Audit Methodology

The CSLC Mineral Resources Management Division completed SAMS interviews with DCOR staff and sub-contractors in April of 2016. Interviews were evaluated according to SAMS guidelines. A separate confidential report summarizing the results was generated for the exclusive use and benefit of DCOR.

Appendices

DCOR, LLC
Platform Esther
Seal Beach

Appendix A
Acronyms

ANSI	American National Standards Institute
API	American Petroleum Institute
ATS	Automatic Transfer Switch
BAT	Best Achievable Technology
BBS	Behavioral Based Safety
BSEE	Bureau of Safety and Environmental Enforcement
CCOR	California Code of Regulations
CEC	California Electrical Code
CFC	California Fire Code
COFR	Certificate of Financial Responsibility
CPU	Central Processing Unit
CSLC	California State Lands Commission
DCS	Digital Control System
DOT	Department of Transportation
EFI	Equipment Functionality and Integrity
EIT	Equipment Improvement Team
ELC	Electrical
EPA	Environmental Protection Agency
ESD	Emergency Shutdown
ESP	Electric Submersible Pump
ESS	Emergency Support Systems
FA	Fire and Abandon
FO	Fiber Optic
FRC	Fire Retardant Clothing
FSL	Flow Safety Low
FSV	Flow Safety Valve
GDE	Gas Detection Element
HF	Human Factor
HMI	Human Machine Interface
H_2S	Hydrogen Sulfide
ICS	Instrument Control Services
IR	Infrared
JSA	Job Safety Analysis
kVA	KiloVolt Amperes
kW	Kilowatts
LACT	Lease Automatic Custody Transfer
LEL	Lower Explosive Limit
MCFD	Thousand Cubic Feet per Day
MOC	Management of Change
MRMD	Mineral Resources Management Division
MSDS	Material Safety Data Sheet
MSRC	Marine Spill Response Corporation
NEC	National Electrical Code
NFPA	National Fire Protection Association
NGR	Natural Grounding Resistor
OSHA	California Occupational Safety & Health Administration
OSPR	Office of Spill Prevention and Response
OSRO	Oil Spill Removal Organization
OSRP	Oil Spill Response Plan
OSRV	Oil Spill Response Vehicle

PC	Personal Computer
PFD	Process Flow Diagram
PHA	Process Hazard Analysis
P&ID	Piping and Instrumentation Diagrams
PLC	Programmable Logic Controller
PM	Preventative Maintenance
PPE	Personal Protective Equipment
PRC	Public Resources Code
PSH	Pressure Safety High
PSHL	Pressure Safety High-Low
PSIG	Pounds per Square Inch Gage
PSL	Pressure Safety Low
PSM	Process Safety Management
PSV	Pressure Safety Valve
PXP	Plains Exploration and Production Company
RFI	Resettable Fault Interrupter
RP	Recommended Practice
SAC	Safety Analysis Checklist
SAFE	Safety Analysis Function Evaluation
SAMS	Safety Audit of Management Systems
SB	Seal Beach
SCADA	Supervisory Control and Data Acquisition
SCBA	Self Contained Breathing Apparatus
SCE	Southern California Edison
SMP	Safety Management Programs
SSV	Surface Safety Valve
TEC	Technical
UBC	Uniform Building Code
UFC	Uniform Fire Code
UPS	Uninterruptible Power Supply
USCG	United States Coast Guard
UV	Ultraviolet
VFD	Variable Frequency Drive

Appendix B
Best Practices

1.0	**BEST PRACTICES**	
1.1	Best Achievable Protection/Best Achievable Technology	PRC 8750
	Inspection of Marine Facilities	PRC 8757
	CSLC Oil & Gas Regulations	CSLC 2 CCR Art. 3 - 3.6
2.0	**FACILITY CONDITION AUDIT**	
2.1	Methodology for Audit	
2.2	General Facility Conditions	
	2.2.1 Housekeeping	CSLC 2123 & 6539
	2.2.2 Stairs, Walkways, Gratings, & Ladders	CAL OSHA Title 8 CCR
	2.2.3 Escape/Emergency Egress/Exits	CAL OSHA 22, 25, 3215 & 6577
	2.2.4 Labels, Placards, & Signs	CAL OSHA & API RP 14J
	2.2.5 Security	CSLC 2123
	2.2.6 HAZMAT Storage	OSHA 29 CFR 1910.1200
2.3	Field Verification of Plans	
	2.3.1 PFD	CSLC 2132(a)(2) & API 51R
	2.3.2 P&ID	CSLC 2132(a)(2) & API 51R
	2.3.3 Fire Protection Drawing	CSLC 2132(g)(4)(G) & API 51R
2.4	Condition and Integrity of Major Systems	
	2.4.1 Piping	CSLC 2129(b) & (c), Cal OSHA 6533, API 570 & CFR 1910.106(c)(4)
	2.4.2 Tanks	CSLC 2129(b) & (c), API RP 653 & 572
	2.4.3 Pressure Vessels	CSLC 2129(b) & (c), ASME Boiler PV Code Sect. VIII, API RP 510 & 572, CCR Title 8 Sec. 6551(c) & 46 CFR 53
	2.4.4 Pressure Relief, PSVs and Flare Sys.	CSLC 2132(g)(3), API RP 14J, 520, 521 & 576
	2.4.5 ESP, Pump Units & Wellhead Equip.	CSLC 2132(a)(4)
	2.4.6 Fire Detection	CSLC 2132(g)(1)(C) & NFPA
	2.4.7 Fire Fighting Equipment and Systems	CSLC 2132(g)(4)(A) & NFPA 25 - 10.2.5.1
	2.4.8 Combustible Gas & H_2S Detection	CSLC 2132(g)(5) & (6)
	2.4.9 Emergency Shutdown Device	CSLC 2132(g)(1) & API RP 14J
	2.4.10 Safety & Personnel Protective Equip	CAL OSHA
	2.4.11 Lighting	CAL OSHA
	2.4.12 Instrumentation, Alarm, & Paging	CSLC 2132(g)(1)&(2), API RP 14J & 8 CCR 5189
	2.4.13 Auxiliary Generator/Prime Mover	CSLC 2132(g)(7)
	2.4.14 Spill Containment	CSLC 2139 & 2140, 40 CFR 112.7(c) & GOV CODE 8670
	2.4.15 Spill Response	CSLC 2139 & 2140 & GOV CODE 8670
2.5	Mechanical Integrity	CSLC 2129(c) & CAL OSHA 8 CCR 5189 (j)
2.6	Offshore Production Safety Systems	CSLC 2132 (g)(1)&(2), API RP 14C, OSHA 5(a)(1), 40CFR 68.65
	Onshore Production Safety System	CSLC 2132 (g)(1) & (2), API RP 14C OSHA 5(a)(1) & 40CFR 68.65

3.0	**ELECTRICAL SYSTEMS AUDIT**	
3.1	Goals and Methodology	
3.2	Hazardous Area Electrical Classification Dwgs.	RP 500, NFPA 70, 496 & CEC 500
3.3	Electrical Power Dist. System, Normal Power	
3.3.1	*Electrical Single Line*	API RP 540, NFPA 70 & CEC 110 & 500.5
3.3.2	*Electrical Service Capacity*	API RP 540, NFPA 70 & CEC 408.4
3.3.3	*Electrical System Design Power*	API RP 540, NFPA 70 & 110 & CEC 110 & 700
3.4	Elec. Power Equip Condition and Functionality	
3.4.1	*Equipment Condition*	API RP 540, NFPA 70 & CEC 110, 314, 344, 408 & 501
3.4.2	*Equipment Maintenance Practices*	API RP 540, NFPA 70 & CEC 110, 314, 490 & 501
3.5	Grounding	API RP 540, NFPA 70 & CEC 250, 408.40 & 501.30
3.6	Emergency Electrical Power	
3.6.1	*System Configuration*	API RP 540, NFPA 70 & 110 & CEC 110 & 700
3.6.2	*Equipment & Component Ratings*	API RP 540, NFPA 70 & 110 & CEC 110 & 700
3.6.3	*Electrical System Design Safety*	API RP 540, NFPA 70 & 110 & CEC 110 & 700
3.7	Electric Fire Pump	API RP 14F, NFPA 20, NEC 696 & CEC 110 & 700
3.8	Process Instrumentation	API RP 14F & 540 & NFPA 70
3.9	Standby Lighting	API RP 14F
3.10	Special Systems	
3.10.1	*Safety Control Systems*	API RP 14C & CEC 110
3.10.2	*Gas Detection System*	API RP 14C
3.10.3	*Fire Detection Systems*	API RP 14F & 14G & API 2001
3.10.4	*Aids to Navigation*	Coast Guard & CEC 110
3.10.5	*Communication*	API RP 14F & CEC 110
3.10.6	*General Alarm*	API RP 14F & CEC 760
3.10.7	*Cathodic Protection*	API RP 651, NACE RP 01-76 & 0675 & CEC 110 & 250
4.0	**SAFETY MANAGEMENT PROGRAMS AUDIT**	
4.1	Goals and Methodology	API RP 75 SEMP, OSHA 29 CFR 1910.119 & CAL OSHA 8 CCR 5189
4.2	Operations Manual	CSLC 2175(b)(4) & (13), CFR 119.119(f) & API RP 51R
4.3	Facility Oil Spill Response Plan	CSLC 2132 (b) & (c) & 40 CFR 112
4.3.1	EPA – SPCC	40 CFR 112
4.4	Training and Drills	CSLC 2175 (b)(6)(C & D) & (7)(A, B, C & D) & OSPR GOV CODE 8670
4.5	Safety Management Programs	API RP 75 SEMP, OSHA 29 CFR 1910.119 & Cal OSHA 8 CCR 5189
5.0	**HUMAN FACTORS AUDIT**	
5.1	Goals of the Human Factor Audit	
5.2	Human Factors Audit Methodology	CAL OSHA 8 CCR 5189, API RP 75 & CSLC Safety Audit of Mgmt Systems

Appendix C
References

GOVERNMENT CODES, RULES, AND REGULATIONS

CSLC	California State Lands Commission
2123	Lease Operations on Uplands
2129	Article 3.3 -Oil and Gas Production Regulations
2132	Production Regulations
2139	Oil Spill Contingency Plan
2140	Pollution Control and Removal Equipment
2173	General Requirements – Operations Manual
2174	Manual Review
2175	Manual Content

Cal OSHA	California Occupational Health and Safety
3215	*Means of Egress*
3222	*Arrangement and Distance to Exits*
3225	*Maintenance and Access to Exits*
3308	*Hot Pipes and Hot Surfaces*
3340	*Accident Prevention Signs*
5189	*Process Safety Management of Acutely Hazardous Materials*
6533	*Pipe Lines, Fittings, and Valves*
6551	*Vessels, Boilers and Pressure Relief Devices*
6556	*Identification of Wells and Equipment*

CCR	California Code of Regulations
1722.1.1	*Well and Operator Identification*
1774	*Oil Field Facilities and Equipment Maintenance*
1900-2954	*California State Lands Commission, Mineral Resources Management Division Regulations*

CFR	Code of Federal Regulations
29 CFR	*Part 1910.119 Process Safety management of Highly Hazardous Chemicals*
30 CFR	*Part 250 Oil and Gas Sulphur Regulations in the Outer Continental Shelf*
33 CFR	*Chapter I, Subchapter N Artificial Islands and Fixed Structures on the Outer Continental Shelf*
40 CFR	*Part 112, Chapter I, Subchapter D Oil Pollution Prevention*
49 CFR	*Part 192, Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standard*
49 CFR	*Part 195, Transportation of Liquids by Pipeline*

INDUSTRY CODES, STANDARDS, AND RECOMMENDED PRACTICES

ANSI	American National Standards Institute
B31.3	*Petroleum Refinery Piping*
B31.4	*Liquid petroleum Transportation Piping Systems*
B31.8	*Gas Transmission and Distribution Piping Systems*

Y32.11	*Graphical Symbols for Process Flow Diagrams*

API American Petroleum Institute

RP 2D	*Operation and Maintenance of Offshore Cranes*
RP 14B	*Design, Installation and Operation of Sub-Surface Safety Valve Systems*
RP 14C	*Analysis, Design, Installation, and Testing of Basic Surface Safety Systems for Offshore Production Platforms*
RP 14E	*Design and Installation of Offshore Production Platform Piping Systems*
RP 14F	*Design and Installation of Electrical Systems for Offshore Production Platforms*
RP 14G	*Fire Prevention and Control on Open Type Offshore Production Platforms*
RP 14H	*Use of Surface Safety Valves and Underwater Safety Valves Offshore*
RP 14J	*Design and Hazards Analysis for Offshore Production Facilities*
RP 51	*Onshore Oil and Gas Production Practices for Protection of the Environment*
RP 55	*Oil and Gas Producing and Gas Processing Plant Operations Involving Hydrogen Sulfide*
RP 500	*Classifications of Locations for Electrical Installations at Petroleum Facilities*
RP 505	*Classification of Locations for Electrical Installations at Petroleum Facilities Classified as Class I, Zone 0, Zone 1, and Zone 2*
API 510	*Pressure Vessel Inspection Code: Maintenance Inspection, Rating, Repair, and Alteration*
RP 520	*Design and Installation of Pressure Relieving Systems in Refineries, Part I and II*
RP 521	*Guide for Pressure-Relieving and Depressuring Systems*
RP 540	*Electrical Installations in Petroleum Processing Plants*
RP 550	*Manual on Installation of Refinery Instruments and Control Systems*
RP 570	*Piping Inspection Code*
RP 651	*Cathodic Protection of Aboveground Petroleum Storage Tanks*
Spec 6A	*Wellhead Equipment*
Spec 6D	*Pipeline Valves, End Closures, Connectors, and Swivels*
Spec 12B	*Specification for Bolted Tanks for Storage of Production Liquids*
Spec 12J	*Specification for Oil and Gas Separators*
Spec 12R1	*Recommended Practice for Setting, Maintenance, Inspection, Operation, and Repair of Tanks in Production Service*
Spec 14A	*Subsurface Safety Valve Equipment*

ASME American Society of Mechanical Engineers

Boiler and Pressure Vessel Code, Section VIII, "Pressure Vessels," Div. 1 and 2

ISA Instrument Society of America

55.1	*Instrument Symbols and Identification*
102-198X	*Standard for Gas Detector Tube Units – Short Term Type for Toxic Gases and Vapors in Working Environments*
S12.15	*Part I, Performance Requirements, Hydrogen Sulfide Gas Detectors*
S12.15	*Part II, Installation, Operation, and maintenance of Hydrogen Sulfide Gas Detection Instruments*
S12.13	*Part I, Performance Requirements, Combustible Gas Detectors*
S12.13	*Part II, Installation, Operation, and Maintenance of Combustible Gas Detection Instruments*

NACE National Association of Corrosion Engineers

- RPO169 *Control of External Corrosion on Underground or Submerged Metallic Piping Systems*

NFPA National Fire Protection Agency

- 20 *Stationary Pumps for Fire Detection*
- 25 *Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems*
- 70 *National Electric Code*
- 704 *Identification of the Hazards of Materials for Emergency Response*

CEC California Electric Code

Appendix D
Team Members

FACILITY CONDITION TEAM

CSLC – MRMD	Mark Steinhilber David Rodriguez P.W. Lowry David Calderon
DCOR	Dave Hayes Nick Holmes Frankie Nauta Matt Civitelli

ELECTRICAL TEAM

CSLC – MRMD	Mark Steinhilber David Rodriguez
PES	Doug Effenberger
DCOR	Dennis Conley

TECHNICAL TEAM

CSLC – MRMD	Mark Steinhilber David Rodriguez P.W. Lowry Steve Staker David Calderon
DCOR	Dennis Conley Matt Civitelli

SAFETY MANAGEMENT TEAM

CSLC – MRMD	Mark Steinhilber David Rodriguez P.W. Lowry Steve Staker David Calderon
DCOR	Scott Knight