Safety and Oil Spill Prevention Audit

DCOR, LLC

Platform Eva

November 2022

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Executive Summary

DCOR, LLC

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EXECUTIVE SUMMARY

Safety Audit of DCOR, LLC (DCOR), Platform Eva

A Safety and Oil Spill Prevention Audit of DCOR, LLC's Platform Eva began in June 2021. Safety and Oil Spill Prevention Audit Team fieldwork was completed in December 2021. The electrical portion of the audit was performed by a third-party – P2S, Inc. – and fieldwork was completed in June 2022.

The objective of this Safety and Oil Spill Prevention Audit is to ensure that oil and gas production facilities on State granted lands are operated in a safe and environmentally sound manner, comply with state and federal regulations, and meet the Best Achievable Protection (BAP) requirement of Public Resources Code 8755. This audit followed the established procedures that have been used by the California State Lands Commission (Commission) for many years. Applicable regulations and standards used during this audit are provided in Appendix C. Audit findings are based on and reference these regulations and standards.

Company Background

DCOR, LLC (DCOR) is the current owner and operator of Platform Eva. The company was formerly known as Dos Cuadras Offshore, LLC and changed its name to DCOR, LLC in 2005. DCOR was founded in 2001 and is based in Oxnard, California with additional offices in Dallas, Texas. DCOR operates two offshore oil production platforms within State waters. The company is owned and controlled by Mr. William M. Templeton.

Facility Description

Platform Eva is located 2.1 miles offshore of Huntington Beach, California on State Oil and Gas Leases PRC 3033.1 and PRC 3413.1, in 58 feet of water. Produced crude oil undergoes phase separation on the platform and is transported to the onshore Fort Apache facility through a subsea pipeline for further processing.

Platform Eva's operations are currently suspended following the discovery of a leak in the subsea pipeline connecting it to the Fort Apache onshore facility in December 2021. Prior to the suspension of operations, the facility produced roughly 840 barrels of oil per day (BOPD) and 165 thousand cubic feet per day (MCFD) of natural gas.

The oil producing formations are typically below hydrostatic pressure and require artificial (mechanical) lift to produce. Thus, the potential for a well blowout is small. The offshore wells are produced using electric submersible pumps.

Safety Audit Results

The Safety and Oil Spill Prevention Audit found that Platform Eva complies with applicable safety and regulatory requirements apart from the items listed in the action item matrix. 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 the steel plate flooring on the Production Deck.

DCOR has established behavior-based safety policies, health, and environmental programs. Operations personnel are knowledgeable and provided valuable assistance to the State Lands Audit Team. The established safety culture also helps to ensure the protection of workers, the public, and the environment.

Safety systems and equipment remain fit for service. However, a few tanks and pressure vessels were past due for internal inspections or ultrasonic thickness measurement. Without consistent inspection and condition assessments the equipment may not meet the intended requirements under operating and upset conditions. Risk reduction and environmental protection can only be ensured though scheduled inspections, testing, and preventive maintenance practices.

Action items from the audit are categorized into three subject areas: equipment function and integrity (EFI), electrical (ELC), and safety management programs (SMP). Each of these action items are assigned a priority ranking from one to three: priority one action items pose a high or immediate risk to personnel, the facility, or the environment and must be resolved within 30 days of this report; priority two action items pose a moderate risk potential and must be resolved within 120 days; and priority three action items pose a low-risk potential and must be resolved within 180 days.

The Mineral Resources Management Division (MRMD) Safety Audit Team identified a total of 81 action items, a 16% reduction from the previous audit. The current audit found no priority one action items. The number of priority two action items increased slightly to sixteen from fourteen in the previous audit. The number of priority three action items decreased from 82 to 65. This is a favorable result as the number of action items is on par with comparable facilities.

Figure 1 displays the distribution of the action items by subject areas. This distribution is similar to other facilities in California where the items identified are typically related to process equipment, maintenance practices, and electrical systems.

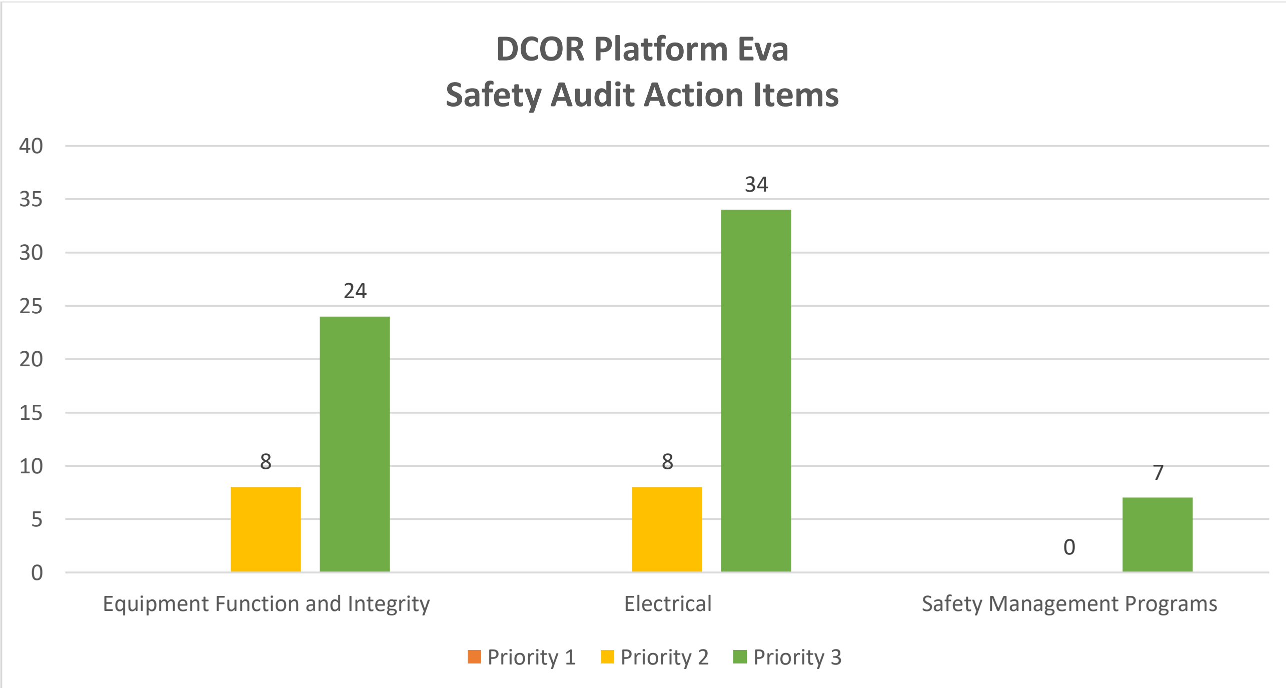
DCOR Platform Eva
Safety Audit Action Items
40
35
30
25
20
15
10
5
0
8
24
8
34
0
7
Equipment Function and Integrity
Electrical
Safety Management Programs
Priority 1
Priority 2
Priority 3

Figure 1

Introduction

DCOR, LLC

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1.0 INTRODUCTION

1.1 Safety Audit Background

The California State Lands Commission (Commission) Mineral Resources Management Division (MRMD) conducts safety and oil spill prevention audits of operators and/or contractors for lands in which the State has an interest. Commission sponsored safety audits ensure oil and gas production facilities on State leases or granted lands are operated in a safe and environmentally sound manner and comply with Federal, State, and Local codes or permits, as well as industry standards and practices. Commission staff is tasked with oil spill prevention in California's ocean and tidelands, prevention of waste, conservation of natural resources, and ensuring that safety and health standards are being met. Public Resources Code (PRC) 6103, 6108, 6216, 6301, 6873(d), 8755, and 8757 provide authority for Commission regulations, as well as the Safety Audit program.

In 1990, the California Legislature enacted the Lempert-Keene-Seastrand Oil Spill Prevention and Response Act (California Government Code 8670.1). The Act covers all aspects of marine oil spill prevention and response in California. Under the legislation, marine facilities must provide the Best Achievable Protection (BAP) of the coast and marine waters.

Frequent monitoring and inspections by MRMD staff of onshore and offshore oil and gas drilling and production facilities ensure that BAP is in place to safeguard the public and environment. The MRMD Safety Audit Program, in conjunction with the monthly inspection program, helps prevent oil spills and other accidents with on-site inspection and verification activities. The Safety Audit Program also aids prevention through design review of facility producing, processing, and safety systems, maintenance condition, operating procedures, emergency plans, training and certification programs, human factors, and other aspects of safety management.

During a safety and oil spill prevention audit, MRMD team members systematically assess an organization's facilities, review safety management programs, identify action items to be addressed, and provide feedback for improvement in preparation of a written report. Their areas of emphasis include:

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

Appropriate company contacts and resources are identified prior to the start of the safety audit. Progress reports are communicated to MRMD management personnel and the company throughout the safety audit process and an "action item matrix" has been developed to categorize and track action items. The matrix contains recommended corrective actions and a priority ranking for the specified corrective actions. A graph and table are generated showing the breakdown of the facility's identified action items by area of emphasis.

Draft copies of the report and the action item matrix are provided to the company during the safety audit. The final report is presented to company management formally, which affords the opportunity to discuss the findings and the corrective actions proposed. Throughout the clearance phase of the safety audit, the MRMD team continues to communicate with the company in resolving the action items and tracks the progress of the proposed corrective actions.

This program could not be successfully undertaken 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 oil spills. Previous experience shows safety assessments help increase operating effectiveness, efficiency, and lower operating costs.

1.2 Facility Background

Platform Eva 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 in 58 feet of water, 2.1 miles offshore of Huntington Beach, California on State Oil and Gas Leases PRC 3033.1 and PRC 3413.1. The Huntington Beach field was discovered on May 24, 1920, when Standard Oil Company struck oil onshore at 2,199 feet.

Platform Eva began operation in 1963 as an asset of Union Oil Company of California (Unocal). The facility has since had various owners and operators including Unocal, Nuevo Energy Company, and Plains Exploration and Production Company. Platform Eva is currently owned and operated by DCOR, LLC (DCOR). DCOR is an oil and natural gas exploration and production company with offices in Ventura, California and Dallas, Texas. DCOR explores for, produces, gathers, processes and markets crude oil, natural gas, and natural gas liquids. They own and operate eleven offshore platforms, two of which are in state waters (Platforms Eva and Esther).

Platform Eva's operations are currently suspended following the discovery of a leak in the subsea pipeline connecting it to the Fort Apache onshore facility in December 2021. Prior to the suspension of operations, the facility produced roughly 840 barrels of oil per day (BOPD) and 165 thousand cubic feet per day (MCFD) of natural gas.

1.3 Facility Description

Platform Eva is a vertical, 12-legged jacket structure anchored to the ocean bottom with pilings at the bottom of the legs. The platform has two primary decks and one small subdeck. At least two operating personnel per shift continually operate the platform and monitor operations. Transit to the platform is provided by SoCal Ship Services crew boat from Seal Beach. Visitors and contract personnel vary depending on platform operations and maintenance needs.

The platform consists of a drill deck, production deck, and subdeck. The drill deck houses a mobile platform for the drill rig, cranes, welding shop, and injection filters and pumps. It is also used to stage equipment for drilling and well maintenance operations, as well as operating supplies, such as chemical totes. The production deck houses the well bay, production and injection wellheads, process tanks, pressure vessels, and pumps. This deck also contains the control room, equipment shop, storage rooms, electrical switchgear, and other equipment required to support platform production operations. The subdeck, located below the production deck, contains the wastewater collection tank and pumps which are used to capture liquids and rainwater recovered from process and gravity drains.

Platform Eva has 24 production wells and 12 injection wells. Prior to taking the platform offline, there were 16 active production wells and 11 active water injection wells. Platform Eva's crude emulsion is shipped via subsea pipeline to the Fort Apache onshore facility on Algonquin Street in Huntington Beach for further processing and lease automatic custody transfer (LACT) unit sales into a third-party pipeline network. Produced gas is shipped by subsea pipeline to Platform Edith in federal waters for use as turbine fuel.

Facility Condition Audit

DCOR, LLC

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2.0 FACILITY CONDITION AUDIT

2.1 Goals and Methodology

The goal of the facility condition portion of the audit was to evaluate the current equipment maintenance and integrity of Platform Eva. The on-site inspection involved a systematic evaluation of the different systems, equipment, and facilities using various checklists and methods that the team has developed over the years of auditing. A variety of codes and standards apply in addition to Commission regulations. Initial tasks to accomplish this goal included field verifications of the key drawings/plans, overall condition inspection and evaluation, a review of system and equipment maintenance histories, further evaluation of specific systems and equipment using checklists, technical review of safety systems design, and verification of compliance with applicable state regulations and industry codes. The layout of the audit report generally follows a “system by system” method that includes a description and assessment of the facilities with any significant observations. The report addresses the safety of personnel as well as facility and process safety. The assessments of both areas of safety are important when identifying an organization’s current level of safety program development.

2.2 General Facility Conditions

2.2.1 Workplace Housekeeping: Platform work areas were clean and orderly, free of slip and trip hazards, waste materials (e.g., refuse, oilfield wastes), and fire hazards. Acceptable refuse containers were provided, and no noticeable waste was on the platform. Regularly scheduled collection of waste contributes to good housekeeping practices. Employee facilities are adequate, clean, and well maintained. DCOR contracts RedFox Environmental to service Platform Eva’s marine sewage treatment unit. Restrooms are supplied with plenty of handwash, paper towels, and there are no other obvious health or sanitation concerns. The marine treatment unit used is certified and meets International Maritime Organization (IMO) & United States Coast Guard (USCG) standards (ex. IMO Marine Environmental Protection Committee (MEPC) 227(64)).

Drip pans and a constructed containment drain system are used throughout the platform to prevent spills and pollution. If a substance accidentally drips onto the deck, personnel clean it up immediately. Absorbent materials are stored in quickly accessible drum-tote containers or bins and are available for wiping up greasy, oily residue or other liquid spills. Tools are available and stored in suitable fixtures for easy access. They are quickly returned after each use and regularly inspected, cleaned, and taken out of service if visibly worn or damaged. Management policies require workers to pay attention to good housekeeping practices as a basic part of accident and fire prevention.

2.2.2 Stairs, Walkways, Gratings and Ladders: Walkways on Platform Eva were in good to poor condition due to the effects of oxidation and possible corrosion in some walkways, primarily on the Production Deck. In general, aisles, passageways, stairs, and gratings had sufficient safe clearances, were in good repair, and were clear with no obstructions across or in the aisles to create a hazard. It appears some sections of grating located in the well bay area need an integrity evaluation to determine their stability and strength. Safeguards were in place in almost all places where there was a need to transition between levels and for routine access to equipment. The elevated work platform to access the test separator vessels did not have an appropriate safeguard at the fixed ladder opening. (*Action Item EFI 2.2.2.01*). Portable ladders were observed to be in good usable condition and free from oil and grease. Fixed metal ladders and appurtenances were painted to resist corrosion against environmentally harsh conditions. DCOR's safe work practices cover the use and care of ladder equipment in the facility.

2.2.3 Escape / Emergency Egress / Exits: Emergency egress/exit points are clearly marked, accessible, and are covered as part of the initial orientation training to access Platform Eva. Evacuation routes are also reviewed during safety meetings and as part of the work permit system. They are identified with signs posted throughout the platform. During an upset condition, the audible difference in the alarm tones as well as announcements over the public-address system (PA) directs personnel to the appropriate safe briefing area.

Windsocks are located for maximum visibility and appeared to be in good condition. Crew boat is the typical means of transport for both operating and contract personnel working on the platform and during emergency evacuation. Evacuation by helicopter is also an option. The design of Platform Eva's primary and secondary or emergency boat landings are considered adequate for their use. No access or egress issues were identified.

2.2.4 Labeling, Color Coding and Signs: The design, application, and use of signs and symbols on the platform define specific workplace hazards. DCOR adheres to the Occupational Safety and Health Administration (OSHA) regulations and American National Standards Institute (ANSI) recommendations. All employees receive instruction on what the signs signify and what, if any, special precautions are necessary to perform their tasks safely. Workplace hazards (e.g., slip, trip, overhead clearance) are marked in yellow. Areas of the protective coating paint on the fire safety equipment piping segments were either faded or missing in the well bay and drill deck areas. An identifiable red protective coating to all fire service piping is required by the National Fire Protection Association (NFPA).

Warning signs were posted properly to identify known safety hazards. They were visible and identified safety hazards. Signs are also posted at each wellhead to identify the lease and well number.

Hazard diamonds were visible on all tanks, vessels, and chemical storage totes. The posting of hazard diamonds is an indication of good facility emergency planning and conformance with the NFPA 704.

2.2.5 Security: Physical and operational security measures are in place on Platform Eva to prevent unauthorized entry. The platform is staffed twenty-four hours a day, seven days a week with at least two operators during normal operations. There is a limited route of access from the boat landing and restricted access signs are posted which are visible from all sides. Approved personnel traveling to the platform must be prelisted on an approved boat log before boarding. Ship Services deckhands check that each person's name appears on the boat log, as well as checking for proper identification and swing rope certification.

2.2.6 Hazardous Material Handling and Storage: Flammable and combustible liquids were found properly stored and documentation readily available, corresponding to Cal/OSHA and NFPA 30 regulations. The bulk chemical totes, and diesel storage were correctly labeled, appeared structurally sound, and had adequate containment in the event of a leak. No loose combustible material or opened empty totes/drums were seen on the premises.

Stored 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 placed where they would not be knocked over or damaged.

Safety Data Sheets (SDS) containing information on all chemicals used in the workplace were up-to-date and accessible to all employees. SDSs are provided at the site of chemical use (chemical injection skids, individual totes) by storing copies in document boxes throughout the facility.

2.3 Field Verification of Plans

2.3.1 Process Flow Diagrams (PFD): The PFD drawings are considered a part of the necessary design documentation for a facility. The PFD drawings for each of the facilities showed the flow through the platform and most of the process drawings were up to date. Some minor changes were needed to reflect current equipment.

2.3.2 Piping and Instrumentation Diagrams (P&ID): A comprehensive field verification of P&IDs was performed for Platform Eva. Several drawings required revisions with some minor updates to include text changes, sizing errors or modifications to valves and piping connections, missing equipment, and out of service or removed equipment.

2.3.3 Fire Protection Drawings: Firewater / Foam Utility Flow Diagrams were available and reviewed for accuracy with some updates or corrections needed. These drawings show important information about the fire-fighting system including the electrical and diesel fire pumps, the fire main, and distribution system. The location of main pipeline valves, deluge system, foam system, hose reels, and emergency connections are all clearly identified.

2.4 Condition and Integrity of Major Systems

2.4.1 Piping: An external visual inspection of the piping systems at all locations on the platform was performed in conjunction with P&ID verification. This visual inspection and evaluation work observed the condition of the piping, painting, and coating, and checked for signs of misalignment, vibration, or leakage. The evaluation of the condition of pipe hangers and supports appeared to be in good condition, though some supports were missing from the Test Oil Header in the Well Bay. The evaluation considered other key information such as material selection, piping design, maintenance practices, as well as any field modifications or temporary repairs not recorded on the piping drawings. The selection process of piping materials and components (e.g., valves, flanges, bolts, welds, transitions, and connections) are compatible with the operating parameters and environment. The condition and maintenance of piping throughout the facility were found to be generally good. However, the field survey identified some corrosion present in the well-bay and production deck areas. The Commission staff recommends DCOR conduct a failure analysis of platform paints and coatings and determine which systems are most in need of painting.

DCOR uses a combination of ongoing routine and risk-based piping inspections to achieve the desired level of facility safety, environmental protection, and reduce unscheduled downtime. Inspection frequencies and condition changes are set up according to regulatory requirements and established guidelines (i.e., American Petroleum Institute (API) 570, American Society of Mechanical Engineers (ASME) B31.3, National Association of Corrosion Engineers (NACE) guidelines, NFPA, etc.). Results from thickness measurements, inspections, repairs, and other tests are readily available and recorded within a computer-based Microsoft Access database. A maintenance management system called Mainsaver is used to generate work orders for maintenance and inspection activities.

2.4.2 Tanks: There are three active tanks on Platform Eva: shipping tank V-103, storage tank T-101, and well cleanup tank T-102. In the past, DCOR has reclassified a few pressure vessels to atmospheric tanks. This change allows DCOR to alter their inspection frequencies and shell thickness requirements, extending the life of the equipment. The three tanks appear to be in good condition and have been inspected within API 653 guidelines. Facility tanks are subject to DCOR's written inspection and maintenance plan.

The maintenance plan follows API Recommended Practices (RPs) and standards. The maintenance strategy also conforms to applicable State regulations and uses appropriate work practices and procedures. Routine external/internal maintenance inspections occur on a five-year cycle and more often if conditions require it. Tank documentation includes inspections, repairs, alterations, and reconstruction records. In addition, tank shell ultrasonic thickness data showing locations and results are completed as part of the inspection process. This inspection method searches for flaws and service induced damage as part of determining the suitability of the tank for the intended service. Tank exterior coatings, piping, valves, walls, anchor bolts, and labeling appeared to be in good condition with no evidence of recent damage or active leaks.

2.4.3 Pressure Vessels: Platform Eva pressure vessels are also maintained following a program of external and internal examination for compliance with applicable regulations, recommended practices, (e.g., API 510 and MRMD 2132(g)(3)), and recordkeeping. These pressure vessels are built according to the American Society of Mechanical Engineers (ASME) Codes and have appropriate controls and safety devices. To improve maintenance efficiency, DCOR has tailored inspection cycles to match the safety risks posed by particular classes of pressure vessels. DCOR's Mechanical Integrity Engineer uses vessel wall thickness, corrosion allowance, and minimum thicknesses (t-mins) as well as operating temperature and pressures to determine the inspection frequency. External vessel inspections are completed within 5-year intervals, while internal inspections and thickness measurements are completed within 10-year intervals using non-destructive examination techniques.

Analysis of inspection records determined that inspection frequency is being achieved following API 510 guidelines for the majority of pressure vessels. Inspection recommendations, maintenance activities, and design information are documented and recorded within the pressure vessel's permanent record. External inspection of the pressure vessels found no evidence of leakage, distortion, or cracks at welds or structural attachments, or defects of vessel connections. Internal inspection records show acceptable corrosion rates with no major concerns or defects of the pressure vessels. However, records identified three vessels as having no internal inspections and Ultrasonic Testing (UT) measurements within the last ten years resulting in three Priority 2 deficiencies. (*Action Items EFI 2.4.3.02 – 2.4.3.04*).

2.4.4 Relief Systems: The main 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 system serves the major process vessels and components while other relief devices may be located on smaller ancillary components. It is designed with a vent stack, flame arrestor, and a scrubbing vessel to remove liquid hydrocarbons. If any relief 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 while preventing flames traveling back through the system, should the mixture be ignited, in order to prevent a larger fire or explosion. The flame arrestor is inspected annually for clogging. No deficiencies were noted.

The maintenance and servicing records for all pressure safety valves (PSVs) comply with applicable regulations and recommended standards (e.g., MRMD 2132(g)(3), API Standard (Std) 520, API Std 521, and Cal/OSHA 6551). PSVs were last tested and serviced in March 2022 by Professional Reliable Oilfield Services (PROS). Service records were in order with no action items identified.

2.4.5 ESP, Pump Units, Wellhead Equip.& Well Safety Systems: Safety devices (Pressure Safety Highs/Pressure Safety Lows which deactivate power to the Electrical Submersible Pumps (ESPs)) were verified to be installed on producing wells and flow lines. Monthly safety inspections as required by Commission regulations on Platform Eva are performed jointly by Commission staff inspectors and Eva operators to verify the safe function and operation of all safety devices and to verify production systems integrity. Platform Eva has 24 production wells and 12 injection wells. Prior to taking the platform offline in December 2021, there were 16 active production wells and 11 active water injection wells. No problems were noted.

2.4.6 Firefighting Detection Systems: MRMD regulations and other facility fire protection requirements include fire detection and alarm systems. These systems are intended to provide early warning and notification of a fire situation. The fire alarm to warn personnel may be activated manually or automatically by the detection sensors. Systems typically include:

- Smoke Detectors
- Heat Detectors
- Ultraviolet and Infrared (UV/IR) Detectors
- Gas Detectors
- Hydrogen Sulfide (H_2S) Detectors

Smoke detectors are placed in electrical rooms, offices, and galley. Any detection of smoke or products of combustion will sound the fire alarm over the platform PA when activated. The platform also utilizes 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, emergency shutdown (ESD), and deluge systems. The fire detection system is designed with bypasses to allow for testing. A MRMD inspector witnesses the flame, flammable gas, smoke, and H_2S detectors operation during monthly testing and records the results. No discrepancies were noted.

The fire detection systems on Platform Eva meet MRMD regulations (e.g., 2132(g)(1), 2132(g)(4), 2132(g)(5), 2132(g)(6)(A)) and are appropriate in design and scope. These systems appear to be well maintained and in good operating order with no action items identified.

<u>2.4.7 Firefighting Equipment:</u> The main firefighting system required by Commission regulations and the local fire authority consists of a pressurized fire main system with two pumps, foam system, hose reel stations, and a deluge system that covers both the well-bay and production deck areas. Platform Eva's fire pumps are both vertical shaft turbine-type pumps. The primary fire pump is electric-driven, and the secondary drive is a diesel-powered John Deere Clarke fire pump. Other firefighting equipment includes a 200-gallon foam tank system that supplies the deluge system, hose reel stations, portable dry chemical and CO_2 fire extinguishers are well located throughout the platform. The firefighting systems are installed and maintained under NFPA 20 and 25 standards per MRMD 2132(g)(4).

The annual and five-year State Fire Marshal testing are mandated under California Code of Regulations (CCR) Title 19. Inspection, testing, and maintenance of Platform Eva's firefighting system was last performed by Joy Equipment Protection, Inc. in March 2021. Testing of the foam system (3% aqueous film-forming foam, AFFF) is performed regularly to determine concentrate for contamination and dilution. No deficiencies were noted.

The firewater hose stations are strategically located throughout the platform and arranged to provide coverage of the target area from two different directions. Portable fire extinguishers are the dry chemical type and appear to comply with MRMD 2132(g)(4)(F), NFPA, and OSHA regulations. Portable fire extinguishers are visually inspected monthly, maintained in a fully charged and operable condition, kept in their designated places, and subject to an annual maintenance check. However, several hose reels commonly exposed to outside conditions did not have their required protective covers.

The firewater piping and fittings appear to be properly supported and adequately maintained. However, some piping in isolated areas were found to have excessive surface corrosion damage or missing identifiable protective paint coating. The Commission staff recommends DCOR conduct an evaluation of the firefighting piping to determine which require reapplication of red, protective coating.

<u>2.4.8 Emergency Shutdown System (ESD):</u> The platform is equipped with six manual ESD stations that comply with MRMD 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. The six manual ESD stations on Platform Eva are tested monthly in bypass mode to ensure automatic shutdown systems are functioning properly. Commission 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 shut down as designed.

Combustible and H_2S gas detection systems are intended to provide warning of a hazardous condition that could lead to a fire or toxic gas release. Combustible gas and UV/IR flame detection systems are located at key locations on the platform. Additional gas detection is located within the MCC/PLC building, operations control room, and safe welding area. These LEL monitors and gas detection systems produce a distinct audible alarm. They alert personnel to the presence of low-level concentrations (25% of LEL) of flammable gas/vapor by a computer-generated alarm and a local beacon. As the concentration of the gas approaches 45% of LEL, the emergency shutdown (ESD) of these units occurs. The ESD system appears fully compliant with API RP 14C. No problems were noted.

MRMD 2132(g)(6) requires a detection system for offshore production facilities where production is known to contain H_2S. These detectors do not initiate shut-in/isolation actions but provide distinct audible and visual alarms when the concentration of H_2S reaches 10 ppm. When H_2S concentrations reach 20 ppm, the audible alarm becomes a solid tone, and personnel follow procedures to move to safe briefing areas. All H_2S and combustible gas detection systems were inspected and found to be in good working order and met Commission requirements. Calibration, testing, and maintenance of this system are conducted and recorded monthly by DCOR personnel. Testing of the sensors and system is included in the Commission staff monthly safety inspection.

Hydrogen sulfide dispersion modeling assessed the risk of a gas release on Platform Eva. The model predicted a radius of exposure (ROE) for varying hydrogen sulfide concentrations for both continuous and instantaneous releases to determine whether additional safeguards are needed. No action items were identified.

2.4.9 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 hat, safety glasses, hard toe boots, fire resistant clothing (FRC), and personal H_2S monitors. Additional 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). No issues about the use of PPE were noted while on the platform.

The Commission staff observed one missing accessible emergency eyewash and shower combination unit in the well bay area where operators are exposed to potential chemicals corrosive to the eyes and skin. This finding was communicated to DCOR personnel and work orders were generated and scheduled for installation. (*Action Item EFI 2.4.9.01*) Other witnessed deficiencies on the production deck were missing physical safety barriers for personal protection where they are not currently provided (*Action Items EFI 2.4.9.02 – 2.4.9.03*).

2.4.10 Instrumentation, Alarm and Paging: The process alarm and control instrumentation has evolved into digital control through previous 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, programmable logic controllers (PLCs) are used to control and monitor all the process equipment and instruments on the platform. Operations management software (Wonderware) provides the operator interface displaying plant-wide status and events. The software can also detect instrument malfunction and equipment failure. This capability, in combination with optimizing features of process control, makes both startup activity and operational routines much easier and more efficient for operators. Wonderware also supports information management that shows historical information that can be used to improve process efficiency and plant performance.

The computer screens used by the operators to operate the facility are known as Human Machine Interfaces (HMI). There are simple graphic displays that mimic the process on the operator's console, located on the platform in the main control room. The HMI displays at this facility allow the operator to access information and control the process in an uncomplicated manner. Common operator actions possible from the displays include:

- Setpoint change
- Mode selection (Auto or Manual)
- Output change
- Trending
- Alarm management
- Report(s) generation
- Shutdown of selected processes

The integrated alarm systems give an audible indication to alert the operator that an alarm has been activated. The visual indication is then used for alarm identification and evaluation. These audible tones are different for each process location. This difference in sound is used to help operators identify the origin of the alarm. Computer-generated process alarms are capable of being displayed and are audible throughout the platform.

The display methods and components are consistent throughout the HMI screens. Adequate information is contained in each of the video displays and all functions are labeled for quick assessment of key information. The graphic displays are concise and clear-cut, reducing the possibility of confusion and operator error.

The facility alarms each month are tested and calibrated. Records are readily available, and the device history can be tracked. All local instrumentation (e.g., pressure gauges, temperature gauges, and recorders) appeared to be properly maintained and in good operating condition. The design and logic of these systems are further addressed in subsection *2.6 – Production Safety Systems*.

<u>*2.4.11 Auxiliary Generator / Prime Mover:*</u> A Caterpillar Model C-9 250 KW diesel generator provides essential backup electrical energy in the event of a power failure. Manual transfer switches isolate circuits from incoming electrical service. If the generator is running and power is restored, these switches keep the primary power electricity from traveling to isolated circuits until the generator is turned off and the switch is reset to the non-backup position. This method of operation allows for the safe transfer and operation of emergency power.

The diesel generator is exceptionally clean and appears well maintained. The generator provides 48 hours of power, without refueling, for all platform lighting, control room, galley, weld shop including 480 Volt service for welding, essential pumps, uninterruptible power supply (UPS) main power supply, Alaska crane, HVAC blower # 2, air compressor B and foghorn. The generator is tested monthly as part of the Commission safety inspection to verify the operational reliability of the system. Historical data shows that routine maintenance is being performed on generating system components and that load tests are acceptable.

2.4.12 Spill Containment: Spill containment equipment for Platform Eva appeared to be adequate and in good condition. A 6-inch lip at the bottom of the handrails traversing the entire production deck and drill deck serves as passive containment. Deck drains handle rainwater, spills, and process leaks. The drain system should be cleared of debris and inspected regularly to prevent abnormal condition leaks. The drain fluid is routed to the Wastewater Tank located on the Sub Deck. Fluids from the Wastewater Tank are then pumped to the shipping tank.

Spill supplies are maintained and inventoried on a monthly basis by DCOR operating personnel and are part of the Commission monthly safety inspection. Platform Eva meets all state requirements for spill containment.

2.4.13 Spill Response: The DCOR Oil Spill Response Plan (OSRP) was developed following Federal and State Facility Response Plan requirements and is discussed in more detail in the Safety Management section of this report.

DCOR maintains other equipment kept on the platform specifically for spill response including sorbent boom and pads, marine radios, company radios and phones, tracking flags, and electronic tracking buoys. In general, the equipment appears to be well kept and is part of the Commission staff monthly safety inspection.

DCOR is a member of a cooperative of oil producers, refiners, transporters, and shippers that provide funding to Marine Spill Response Corporation (MSRC). MSRC is a national, nonprofit USCG classified Oil Spill Response Organization (OSRO) with a large inventory of vessels, equipment, and trained personnel. Locally, 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. The last Office of Spill Prevention and Response (OSPR) spill drill and boom deployment at Platform Eva occurred on July 1, 2021.

2.4.14 Cranes: Platform Eva is equipped with two cranes, one electric powered 130-foot boom Seatrax crane nominally rated at 44 tons and a smaller electric-driven 40-foot boom Alaskan crane. The industry standard for cranes is API RP 2D, Operation and Maintenance of Offshore Cranes. Additionally, cranes in state waters are subject to Cal/OSHA regulations pertaining to cranes. DCOR employs crane mechanics, who inspect and repair the cranes on DCOR platforms and load tests are performed by RA Batchelor Co. crane services. The audit staff observed training and re-certification of crane operators during the course of the audit. After reviewing crane records, it appears that monthly, quarterly, and yearly inspections are being performed as required. The records also contained documentation to show that needed repairs were being corrected in a timely manner. No deficiencies were identified.

2.5 Mechanical Integrity / Preventive Maintenance Program

The Preventive Maintenance and Mechanical Reliability sections provide a general overview of DCOR's corporate philosophy and approach to implementing a successful reliability program. The section also provides findings when appropriate. Preventive maintenance and job scheduling are controlled by Operations foremen and craft supervisors. New work orders are reviewed daily and assigned to an in-house craft or outsourced to a contractor/vendor depending upon the workload and specific job requirements. Critical spare parts and commonly used parts are stored on Eva or in the onshore warehouse. This approach provides DCOR with maintenance task optimization and decreases the chance of equipment failure. Recordkeeping for PSVs, tanks, and pressure vessels has migrated to electronic files.

The computerized maintenance management system (Mainsaver) is utilized to manage and track activities. Operating personnel can access Mainsaver to generate a work order. These work orders can range from a simple filter change to major equipment repair. Mainsaver gives DCOR flexibility to schedule and record these activities based upon the manufacturer's recommendations, operating history, and recognized and generally accepted good engineering practices. Tank and pressure vessel reliability are maintained through regularly scheduled internal, external, and ultrasonic inspections and repairs. Reliability inspections are also standard for all rotating equipment.

Facility Engineers have developed a risk management system to decrease the incident rate of piping leaks for the various piping systems onboard the platform. These piping systems or sections of piping connect the wells via headers to the processing equipment. A risk level is established for the various sections of piping based on service and consequence of failure. When the risk level for a particular section of piping reaches an unacceptable level, engineers implement a corrective or mitigating action on that section of piping to lower the risk level to an acceptable level. Offshore and onshore facilities use several different methods to improve the life of the various piping systems that include:

- Primer, paint, and tape wrap coatings (External)
- Epoxy coatings and liners (Internal)
- Cement lining
- Cathodic protection
- Chemical treatment

A chemical vendor provides the facility with a chemical treatment program that establishes the operational needs of the offshore facility. A main component of the program is a corrosion inhibitor. The chemical protects the pipe's internal surface and metal components by forming a protective film. Additionally, the program incorporates corrosion coupons at critical points in the piping for monitoring the effectiveness of the chemical treatment program. This means of corrosion control is provided for select pressure vessels and tanks. Appropriate record keeping from regularly scheduled internal, external, and ultrasonic inspections and repairs provide historical data and often give signs as to the source of a detected deficiency.

2.6 Production Safety Systems

Analysis of Platform Eva drawings and PLC logic found that the design of process controls and safety systems is adequately documented, has the appropriate level of safety controls, and is consistent with the previous Commission staff audit. The automated control and safety systems have been designed using applicable codes, standards, and industry practices in accordance with MRMD regulations and API RP 14C.

Platform Eva status, controls, and alarms are displayed in real-time via HMI displays located in the main control room. The automated control system monitors and controls platform processes in separate operating areas. The automated displays help minimize the effects of undesirable events and mitigate consequences from upsets. The safety systems are independent of the DCS alarm system on the platform in case of loss to the communications link.

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.

Safety Analysis Function Evaluation (SAFE) Charts described in API RP 14C are utilized as an analysis technique to document the effects of and determine the requirements for components in the safety system. All safety devices and their functions were analyzed by comparing the SAFE Chart, facility P&IDs, and other documents. The comparison matched all safety and shutdown devices and emergency support systems (ESSs), with their functions and verified that the required level of protection is being maintained. The review identified some discrepancies between the SAFE Chart, other documentation, and actual conditions. The SAFE Chart will need to be updated to reflect the observed compliant conditions. (*Action Item EFI 2.6.01*).

All platform wellheads utilize artificial lift and have safety devices installed to shut off power in the event of abnormally high or low pressures as required by MRMD 2132(a)(10)(A) and API RP 14C. The pressure safety devices are tested monthly by the MRMD Inspections group.

Extensive fire and safety systems are installed throughout the platform. Included in these systems are safety devices that automatically shut down oil and gas production if an emergency occurs. Every operator/contractor on the platform is authorized to shut down the platform should they detect an unsafe condition. As part of the surface production safety system, automatic shutdown valves are installed per MRMD regulations and API RP 14C to isolate the various process systems and lessen the environmental impact should a system problem be identified. Should evacuation be necessary, platform personnel can leave the platform by helicopter, boat, or by using the available life rafts.

DCOR has performed a Hazard and Operability (HazOp) Process Hazard Analysis study for the whole platform. Their Management of Change (MOC) process includes the use of a PHA tool, in a style similar to HazOp, for changes to facilities, equipment, and processes, when the Facility Engineer decides it is appropriate. This systematic approach for identifying, evaluating, and controlling the hazards of the process helps build-in additional safety 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., elimination-substitution-engineering controls-administrative controls-PPE) to eliminate hazards or reduce exposure to hazards.

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Electrical System Audit

DCOR, LLC

Platform Eva

November 2022

3.0 ELECTRICAL SYSTEM AUDIT

3.1 Goals and Methodology

The goal of the electrical (ELC) portion of the audit was to evaluate the electrical systems and operations at Platform Eva to determine conformance to the California Electric Code (CEC) and industry standards.

References used in review of systems, equipment, and facilities include documents published by the American Petroleum Institute (API), National Fire Prevention Association (NFPA), the California Electric Code, and State Lands Commission Regulations. The ELC Team review comments are primarily based on those publications, which include API Recommended Practice (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 Eva.

Specific tasks to accomplish this goal included a systematic process of field verification of electrical single-line diagrams, plan drawings, area classification drawings, arc flash hazard study, 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. Each subsection includes a summary of the electrical systems included in the audit.

The ELC portion of the Action Item 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 Electrical 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. The basis for observations and review comments for all hazardous areas are API RP 500, CEC Articles 500, 501, and 504 as well as API RP 14F. The hazardous area electrical classification drawings are generally representative of the existing conditions and area class elements. DCOR drawings DCOR-EV-EL-D-0001 and DCOR-EV-EL-D-0002 were last revised in March 2016 and require a new update. (*Action Items ELC 3.2.01 – 3.2.02*)

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 to ensure compliance with the CEC. Electrical area classification drawings are required to include the information necessary for a qualified electrician to perform work in and around classified areas.

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 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 (*Action Items ELC 3.2.01 – 3.2.02*). The drawings should be updated to show equipment similar to the Equipment Location Plan.

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. The purge and pressurization systems for the Electrical Switchgear Room and Switchgear Powerhouse rooms could not be verified as operational (*Action Item ELC 3.2.03*).

3.3 Electrical Power Distribution System, Normal Power

<u>*3.3.1 System Configuration:*</u> Electric utility service is supplied by Southern California Edison at 34.5kV via submarine cable from the Southern California Edison SOCO Substation located at service address 20031 Goldenwest St in Huntington Beach. The cable also includes a fiber optic cable for communications, monitoring, and control. (See section 3.10.5)

The onshore service location is at the Edison 66kV switchyard and 34.5kV outdoor overhead disconnect located near the intersection of Goldenwest St and Palm Ave in Huntington Beach. The substation supplies a Cutler-Hammer outdoor power-house (Electro-Center) containing 34.5kV, 1200-amp, 1500MVA Bus and medium voltage metal enclosed vacuum breaker. The breaker supplies power for both Platform Eva and Platform Edith via #1/0 AWG 35kV cable routed in tray and below grade conduit to a nearby vault (manhole F). Within the vault, the cable is tee spliced (using separable splices) to separate submarine cables for Platform Eva and Platform Edith.

The submarine cable to Platform Eva supplies 34.5kV electrical power to an SF_6 gas insulated three position switch consisting of a one disconnect switch for the 34.5kV supply and two 200A vacuum interrupter switches. The first vacuum interrupter position feeds a 3000kVA 34.5kV-480Y/277V transformer TX-1 to supply power to the operating platform main switchgear. The second vacuum interrupter position is connected to a 3000kVA transformer TX-2, 34.5kV-480Y/277V transformer located on the drill deck to supply power to switchgear PDB2 and a second 3000kVA transformer TX-3, 34.5kV-600Y/347V to supply power for drilling operations. At the time of inspection, there were no well casing operations in progress.

The electrical single-line drawings used for this audit were last updated in June of 2015. The drawings are representative of the electrical power system. The audit focused on power distribution systems 480V and above and excluded the lower voltage systems. Copies of the latest single-line drawings were received from DCOR and are available to personnel from the DCOR server files. Discrepancies observed between the installed equipment and the single-line diagrams are listed in the matrix. (*Action Items ELC 3.3.1.01 – 3.3.1.07*) As part of the single-line diagram revisions and arc flash hazard study, it is recommended that the overcurrent protective device short circuit interrupting ratings and overcurrent settings be verified to comply with the Code. (*Action Item ELC 3.4.3.02*)

3.3.2 Electrical Service Capacity: The normal power system capacity appears to be adequate based on present usage observed on switchboard meters. As part of the activity necessary to update the single-line diagrams for the arc flash hazard study, it will also be necessary to confirm the overcurrent device rating is appropriate for the connected equipment. The 480V system operating voltage was noted at 492V at the main switchboard PDB2. The voltage was likely elevated since the platform was not producing oil. System voltage will fluctuate for a variety of reasons. It is recommended that switchboard voltage levels be reviewed and adjusted if deemed warranted. System capacity appears to be adequate for operations. At the time of this audit, the platform was energized but not in production due to an issue with the oil shipping pipeline.

3.3.3 Electrical System Design: The power system installation, in general, appears to be adequate for the present operations.

3.4 Electrical Power Equipment Condition and Functionally

3.4.1 Equipment Condition: Given the harsh environmental conditions of the open sea, the overall condition of electrical equipment can be rated as good. There are several items regarding lack of support for multiple sections of armored cable, valves, lights, and temporary cables. In addition to support, the cables and equipment should be trained and installed to reduce the risk of damage during well drilling and maintenance operations. There are several instances of exposed wiring, non-operational indicating lamps, leaking transformers, and wireways not installed to code. (*Action Items ELC 3.4.1.14, 3.4.1.15, 3.4.1.17, 3.4.1.20, 3.4.1.21)*

3.4.2 Safety Procedures: Section 4.04 of the DCOR Safety Manual covers the hazardous energy control (lockout/tagout/blockout) program. The scope, responsibility, and procedures outlined in the document appear to be adequate and complete.

3.4.3 Equipment Maintenance Practices: There are no maintenance test labels showing when the last preventive tests or checks were done on the electrical switchgear. DCOR should provide the latest set of the test and maintenance records for the circuit breakers, perform testing and maintenance prescribed in NFPA 70B, and install test labels with dates of test and maintenance. (*Action Items ELC 3.4.3.01 – 3.4.3.02*)

The Arc Flash Hazard study was last updated in June 2015. NFPA 70 and CEC 110.16 require arc-flash warning labels to be installed on electrical equipment likely to require examination while energized. Refer to CEC 110.16 for the specific requirements. NFPA 70E provides guidance on how to determine arc-flash incident energy, hazard levels, planning safe work practices, labeling, and personal protective equipment requirements. The arc-flash hazard study and labeling require an update. All equipment requiring labels shall be labeled.

Platform personnel and contractors were not implementing an extension cord and portable equipment testing program. CEC 590 identifies a 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) and marking system for temporary power extension cords and a method to identify when cords were last inspected for safety. (*Action Item ELC 3.4.1.10*)

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. The rules of grounding also contribute to reduction of equipment damage. Three specific types of grounding are required at the facilities: power system grounding, safety or equipment grounding, and static grounding. Transformers of separately derived systems for 480Y/277V, 240/120V, and 208Y/120V are solidly grounded and satisfy Code requirements for power system grounding.

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.

Static grounding conductors to some portable storage containers (some containing hazardous liquids) were found to be missing altogether and are required. (*Action Item ELC 3.5.01*) Additionally, a ground bonding jumper needs to be installed on the MagTech level indicator. (*Action Item ELC 3.5.02*)

3.6 Auxiliary Equipment – Emergency Generator and Secondary Fire Pump (Diesel)

A 250kW/313kVA Caterpillar Model LC5 standby generator is installed to supply 480V emergency power in the event of a loss of utility power. The standby power is supplied to the 480V Standby MCC. The generator has a base fuel tank with 400-gallon diesel fuel capacity. The fuel consumption rate at full load is approximately 20 gallons per hour. The fuel tank must be filled manually since there is no day tank or electric driven fuel pump and system supplied from the platform diesel storage tank. The new diesel engine fire pump has a 65-gallon fuel tank. The tank requires manual re-fueling. Written procedures for refueling the 250kW generator and diesel fire pump should be developed and included in safety training procedures. (*Action Item ELC 3.6.2.02*)

A diesel fire pump was installed in 2019 as a backup to the electric fire pump. It has a 65-gallon fuel storage tank that requires manual refilling. The fire pump engine has a fuel consumption rate of approximately 4.5 gal/hour at full load which equates to approximately 14.4 hours of run time. A written procedure for refueling the secondary diesel fire pump should be developed and included in safety training procedures. (*Action Item ELC 3.6.2.02*)

3.7 Electric Fire Pump System

A 75hp electric fire pump is located on the production deck and controlled through the firewater controller panel located in the MCC room. The electric fire pump has a normal source of power connected ahead of the 4500A, 480V PDB1 main service switchboard breaker in accordance with CEC 695-3(a)(1). Two fire pump start/stop button stations were not represented on DCOR-EV-PL-D-0002. (*Action Item ELC 3.7.01*) A diesel driven 86-hp fire pump, installed in 2019, is also available as a backup in the event of a system power failure.

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, programmable logic controllers (PLCs), 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.

The main servers for Wonderware and process controls are located in the electrician's office on the Production Deck mezzanine. A four-post cabinet houses the 16kVA uninterruptible power supply (UPS), two servers, and routers. The monitors located in the control room include three PCs and two large monitors to provide operator interface to the process control system. The two main PCs are linked to the local Ethernet system and run the Wonderware software package. The third PC is also loaded with the software and may be substituted upon failure of either of the two primary PCs. One other PC is located in the Galley to allow remote monitoring (mimic), but no control, of the system.

An Allen-Bradley SLC 5/30 processor is located in control board CP-1 in the control room and up to five remote PLCs are installed in various locations on the platform and are dedicated to specific tasks and systems control. The PLC-1 in control board CP-1 monitors main control board alarms and functions. The remote PLCs monitor the well point pressures and flow rates, compressor operation, water injection, variable frequency drive (VFD) operation and well data, smoke alarm, temperature in switchgear rooms, and provides outputs for well shutdown. PLCs are interconnected over the RS-485 Data Hwy.

During the site investigation, the PLC and server configuration was discussed, but no formal plans, logic diagrams, or instructions were available for review. No action items were identified related to this system.

3.9 Standby Lighting

Fixtures are installed in conformance with the National Electric 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 Emergency Panels "EDP2", "EMLP-1", and "EMLP-2" which all receive power from the 250kW emergency generator in the event of main power failure. Review of the layout and location of emergency light fixtures indicates adequate provisions for the purpose of safe egress. Emergency lighting is also provided in the Control Room, electrical rooms, and Galley.

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

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.

Six Emergency Shutdown Stations (ESD) are located on the platform. The stations appeared to be in good working order. The stations include ESD-1- bottom of Galley stairs, ESD-2 – south well bay at stairway to Sub-Deck, ESD-3 – Control Room CP-1, ESD-4 – Production Deck near V-114, ESD-5 – boat landing south side, and ESD-6 – east side stairs near weld shop. Stations are hard wired to the control panel CP-1 in the control room. Fail safe relays in panel CP-1 initiate shutdown of the platform and signal to the general alarm's cabinet located in the locker room near the weld shop.

Seventeen Fire, Abandon Platform, and Man Overboard Alarm Stations (EA-1 through EA-17) are located about the platform. All stations appeared to be in good working order. All stations have been painted red; however, the red paint is faded and is no longer prominent. ESD and EA stations are tested monthly, and records are maintained.

3.10.2 Gas Detection Systems: Combustible gas detection systems, lower explosive limit (LEL) and hydrogen sulfide (H_2S), are usually employed to detect combustible gas leaks in equipment and piping, to warn personnel of explosive and toxic concentrations, and to initiate remedial action. Eleven gas detector elements (GDEs) are located as follows: GDE-1-1 at the Drill Deck Weld Shop, on the Production Deck are GDE-1-2 in MCC room, GDE-1-3 near V105, GDE-1-4 near V302, GDE-1-5 near GC-300, GDE-1-6 above GC-240 enclosure, GDE-1-7 near V-5, GDE-1-8 near V-301, GDE-2-1 at north east side of GC-240 enclosure, on the Sub Deck GDE-2-2 near T-103, and GDE-2-3 inside GC-240 enclosure. Signals from the gas detectors are hard wired to the General Monitor Gas Detection Modules (model DC-119-311-120) in the control room panel CP-1. Gas monitors are tested monthly, and records are maintained.

3.10.3 Fire Detection Systems: Fire detection and smoke detection is employed to detect and warn personnel of fire and smoke conditions and to initiate remedial action. Four fire-eye type UV detectors are provided in an Edison loop around the well bay, while fourteen (14) additional UV detectors protect the remainder of the platform (Production and Subdeck). Ten (10) smoke detectors are located about the platform. Signals are returned to the General Monitor Fire Detection Module (FL802) in the control room panel CP-1. Fire and smoke detectors are tested monthly, and records are maintained.

3.10.4 Aids to Navigation: The United States Coast Guard (USCG) no longer requires aids to navigation for Platform Eva. 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. Handheld radios are located in the Control Room. A UPS capable of providing power for four hours supplies the communications equipment and handheld radio chargers.

Incoming Service: A fiber optic (FO) line is included with the incoming 34.5kV submarine cable from shore (HB Strip) to Platform Eva. The fiber optic cable is separated from the power cables at the main interrupter switchgear in the switchgear room and connected to a fiber optic modem and switch located above the 34.5kV SF6 switch. The modem and switch are supplied with uninterruptible power from a UPS that is also located on top of the 34.5kV SF6 switch enclosure through a FO/Ethernet converter to the platform Ethernet. Three phone lines and one fax line extend from the converter panel in the switchgear room to the communications shelter on the drill deck where each phone line is converted from digital-to-analog signal for tie-in to the existing phone system.

The bridge radios for communication to Platforms Edith and Esther are also located in the switchgear room. Communications equipment in the switchgear room is powered through a local UPS unit. The APC Symmetra LX UPS unit, located in the change room, contains two external battery units with capacity to serve the communications equipment for 12 hours.

A radio base station in the communications shelter with a remote terminal in the control room provides radio communication with the crew boat. Antenna for the system is located on the communications shelter. Emergency power is supplied to a panel in the communications shelter from an emergency source of power.

Commercial television reception to TVs in the control room and Galley is provided by coaxial cable from an antenna on the heliport access stair.

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. Each of the following alarms have a unique sound and voice announcement: abandon platform, general process, LEL gas, H_2S gas, and fire.

The only signs observed were in the Control Room. A label above each pushbutton identifies the pushbutton stations for each alarm. Some of these labels at the local stations are difficult to see and read. New legible labels and response signage are required to be installed. (*Action Item ELC 3.10.6.01*) It is recommended that the central paging system be used to supplement instructions of a general alarm. Alarms are tested monthly and found to demonstrate adequate performance in the outdoor areas.

3.10.7 Cathodic Protection: The impressed current cathodic protection system consists of two cathodic protection rectifiers located in the MCC room and eleven total impressed anode locations. Rectifier #1 is connected to the six anodes (1-6) on the West side of the platform (below the drilling area). Rectifier #2 connects to four anodes (7-11) on the East side. Both units appear to be operating. The rectifier operation was verified. It was noted that the impressed current for Cathodic Rectifier 1 was 92A with an upper limit of 90A. This condition was discussed with the platform operator and no action item was identified.

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Safety Management Programs

DCOR, LLC

Platform Eva

November 2022

4.0 SAFETY MANAGEMENT PROGRAMS

4.1 Goals and Methodology

The goal of the safety management program section of the audit was to verify that DCOR has required programs, plans, and manuals in place and that the company uses a safety management approach to manage hazards and thereby 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 California State Lands Commission (Commission) Mineral Resources Management Division (MRMD) Article 3.4, 3.6 and American Petroleum Institute (API) Recommended Practice (RP) 75. The audit began with a review of the Operations Manual, operating procedures, other required emergency and spill response plans, training programs, and additional specific programs that DCOR uses to cover other elements of the safety and environmental management program for Platform Eva.

4.2 Operations Manual – (Platform Eva Operations)

DCOR's Operations Manual outlined the necessary information for employees who work on the equipment to know and understand what procedures or system processes are needed to safely operate an offshore platform facility. Individuals knowledgeable with the process and its hazards write the Standard Operating Procedures (SOPs). These individuals are also familiar with the subject matter and typically have performed the work and operated the process. The SOPs are written in a simplified, easy-to-read format with sufficient detail so that trainees with limited experience or knowledge of the procedure can successfully carry out the task with minimal supervision. Operations validate the procedures contained within the manual before finalization. A thorough review noted that some of the information does not appear to be current or is missing, including personnel roles and contact information, number and identification of active wells, production averages. (*Action Item SMP 4.2.01*). The Operations Manual is required to be kept current at all times and systematically reviewed for routine or subsequent changes identified in MRMD 2174(b) with a copy submitted to the Commission for compliance approval of any changes.

The SOPs are maintained and accessible via the company intranet system to all DCOR personnel and available for print. Hard copy versions are located on the platform in the main office control room. A periodic review of the SOPs by Operations personnel is performed to ensure that pertinent operating information is readily available and correct. The SOPs are also reviewed when operations or equipment are changed. They are updated by authorized DCOR personnel to ensure the contents remain current and the date of review/revision is recorded in each SOP. If an SOP describes a process that is no longer followed, it is removed from the file and/or manual. Some of the operating procedures' information does not appear to be up-to-date or accurate between different sections (*Action Items SMP 4.2.02 – 4.2.05*). For example, equipment location diagrams were not reflective of current platform configuration and conflicting values for operating limits were given in different sections in many operating procedures.

4.3 Spill Response Plans

The DCOR Oil Spill Response Plan (OSRP) was developed following Federal and State Facility Response Plan requirements. The document defines procedures and plans for responding to discharges of oil into navigable waters and seeks to minimize damage to the environment, natural resources, and facility installations. The plan covers Platform Eva, Platform Esther, onshore facilities, and associated pipelines. 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

Also contained within the OSRP are operating procedures the facility implements to prevent oil spills, control measures installed to prevent oil from entering navigable waters or adjoining shorelines, and countermeasures to contain, clean up, and mitigate the effects of an oil spill. The OSRP was reviewed and noted to have a long approval history. It meets Federal (Code of Federal Regulations (CFR) Title 40 Section 112.5) and State Office of Spill Prevention and Response (OSPR), CCR Title 14, Regulation 817.02 standard requirements. DCOR staff is familiar with the OSRP and holds annual spill drills to increase the effectiveness of their spill response. The last comprehensive update of the OSRP was in January 2021, also includes a current copy of the California Certificate of Financial Responsibility (COFR), which expires on December 31, 2023. Spill plans should be reviewed regularly for any changes and to satisfy other related plan requirements, such as the Emergency Response Plan (ERP) that comply with California CCR Title 8 Section 5192(q)(1) & (2) and CFR Title 29 Section 1910.119, are updated. Changes should be managed by authorized DCOR personnel to ensure new or different operating conditions are contemplated, qualified staff is available to perform necessary functions, operator and personnel certifications are current, and information relating to regulatory agencies is up to date. A review of DCOR's Emergency Response Plan (ERP) identified needed updates to personnel roles and equipment location plans. (*Action Item SMP 4.5.02*)

4.4 Training and Drills

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 includes hands-on procedural performance and evaluation. Both the lead operator and operations supervisor must sign off on the training and qualification. Promotion to the next Operator level is based on progression through these operating requirement elements. Successful completion of all 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.

Compulsory OSHA and spill response training is also provided. DCOR conducts annual online training to satisfy Cal/OSHA training requirements. DCOR's administrative training coordinator employs a computer-based training (CBT) matrix that tracks all training activities and is used to alert management and individual personnel of training requirements. All DCOR operating personnel receive Production Safety Systems (API RP T-2) Training, as well as other annual required CBT courses that are developed by DCOR in-house through PetroSkills on-line training programs. The training program 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 API RP 75 that "initial" and "periodic" training be provided to employees and contractors on operating procedures, safe work practices, and emergency response and control. This standard requires that offshore operations and maintenance personnel receive training on safety and anti-pollution devices, maintenance, and crane operation, well control, and hydrogen sulfide, as appropriate. Other regulations include CFR Title 30 Chapter II – the Bureau of Safety and Environmental Enforcement (BSEE).

Spill response team members are trained in the procedures developed for the facility spill plan. This training consists of classroom instruction, exercise evaluation briefings, tabletop exercises, and equipment deployment drills. Exercises range from a discussion about how things would occur to the deployment of equipment and mobilization of staff. Most spill drills are unannounced, and personnel are given a scenario that they must respond to. If DCOR finds any significant deficiencies in the spill plan after a drill or exercise is complete, the company will record the deficiencies and require changes to the plan. DCOR management reviews the lessons learned during oil spills and exercises to revise and improve contingency plans. Revisions of the plan may require additional inspections, drills, and training.

Platform Eva personnel conduct mandatory safety meetings for task specific condition changes or scheduled operator rotation that include all persons performing work on the platform for both general and topic specific safety subjects. Training and pre-job safety meetings are documented; records are retained and available upon request. During fieldwork, the Safety Audit Team observed Platform Eva personnel's acknowledgment of the importance of proper PPE and its use at all appropriate times. There were no action items identified regarding these safety elements.

4.5 Safety Management Programs

DCOR's Safety and Environmental Management Systems (SEMS) plan parallels the API RP 75 for Offshore Operations standard and is used to control workplace hazards. DCOR has voluntarily integrated its corporate safety management program into the facility. This practice has improved its operating reliability, system operating efficiency, and reduced incidents involving the release of hazardous materials beyond the facility boundaries.

DCOR has other written safety plans for facilities that operate under specific hazardous conditions. DCOR's hydrogen sulfide (H_2S) contingency plan is a systematic analysis of the hazards associated with H_2S and the methods required to reduce the hazards to an acceptable level. H_2S Contingency Plan requirements include emergency evacuation procedures, a plot plan of the facility, required personal protective equipment, and other precautions that are necessary to work safely with H_2S. A review of the plan identified deficiencies in the required contents. (*Action Item SMP 4.5.01*).

DCOR's safety policy sets a clear direction for the organization to follow and is a part of their established business performance goals. The objective of their safety policy is to set down in clear-cut terms management's approach and commitment to health and safety at their facilities. Audit team observations and interviews with employees and contractors confirmed that DCOR's senior management has defined, documented, and endorsed its safety policy. Safety management functions within the organization correlate with the safety of their personnel. This connection can be seen in the planning, developing, organizing, and implementing of DCOR's safety policy.

Additional assessment and feedback regarding DCOR's safety management programs will be afforded by the Commission's Safety Assessment of Management Systems (SAMS) that is conducted after the safety and oil spill prevention audit. The SAMS also provides significant benefits regarding human factors observations and assessments described in the next section of this report. The SAMS is a separate effort from this audit and the results are kept confidential between the Commission and the operating company.

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Human Factors Audit

DCOR, LLC

Platform Eva

November 2022

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 SAMS is planned to follow the safety and oil spill prevention audit of the DCOR Huntington Beach lease facilities (Platform Esther, Platform Eva, and Fort Apache Onshore). Interview results are considered confidential between the Commission and DCOR and will be contained in a separate report.

SAMS was developed under the sponsorship of government agencies, including the California State Lands Commission (Commission), 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 several associated and detailed questions to help better define the issues and degree of integration of safety management programs. The SAMS process is not intended to generate a list of action items. Its purpose is to provide the company with a confidential assessment of where it stands in developing and implementing its safety culture, areas of relative strength and weakness, and a benchmark for future assessments.

5.2 Human Factors Audit Methodology

The Commission's Mineral Resources Management Division (MRMD) will schedule individual SAMS interviews with a cross section of DCOR field operators and sub-contractors and engineering, supervisorial, and management staff after the safety audit reports for Platform Eva, Platform Esther, and the Fort Apache onshore facility are completed. Interview responses will be evaluated according to SAMS guidelines and a separate confidential report summarizing the results will be generated. Responses of specific individuals to questions are kept anonymous in the report. The MRMD staff will provide a confidential report accompanied by a formal presentation that summarizes the report to DCOR management.

Action Item Matrix

DCOR, LLC

Platform Eva

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Appendices

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Appendix A
Acronyms

A	Amperes
AFFF	Aqueous Film-Forming Foam
ANSI	American National Standards Institute
API	American Petroleum Institute
ASME	American Society of Mechanical Engineers
BAP	Best Achievable Protection
BEP	Business Emergency Plan
BOPD	Barrels of Oil Per Day
BSEE	Bureau of Safety and Environmental Enforcement
Cal/OSHA	California Occupational Safety and Health Administration
CBT	Computer Based Training
CCR	California Code of Regulations
CEC	California Electrical Code
CFC	California Fire Code
CFR	Code of Federal Regulations
CO_2	Carbon Dioxide
COFR	Certificate of Financial Responsibility
Commission	California State Lands Commission
DCOR	Dos Cuadras Offshore Resources
DCS	Digital Control System
DOT	Department of Transportation
EFI	Equipment Functionality and Integrity
ELC	Electrical
EPA	Environmental Protection Agency
ERP	Emergency Response Plan
ESD	Emergency Shutdown
ESP	Electrical Submersible Pump
ESS	Emergency Support Systems
FO	Fiber Optic
FRC	Fire Resistant Clothing
GDE	Gas Detector Element
HAECD	Hazardous Area Electrical Classification Drawing
HazOp	Hazard and Operability
HF	Human Factors
HMI	Human Machine Interface
H_2S	Hydrogen Sulfide
HVAC	Heating, Ventilation, and Air Conditioning
IES	Illuminating Engineering Society
IMO	International Maritime Organization
IR	Infrared
ISA	International Society of Automation
JSA	Job Safety Analysis
kV	KiloVolt
kVA	KiloVolt Amperes
kW	Kilowatts

LACT	Lease Automatic Custody Transfer
LED	Light Emitting Diode
LEL	Lower Explosive Limit
LLC	Limited Liability Corporation
MCC	Motor Control Center
MCFD	Thousand Cubic Feet per Day
MEPC	Marine Environmental Protection Committee
MOC	Management of Change
MRMD	Mineral Resources Management Division
MSRC	Marine Spill Response Corporation
NACE	National Association of Corrosion Engineers
NEC	National Electrical Code
NEMA	National Electrical Manufacturers Association
NFPA	National Fire Protection Association
OSHA	Occupational Safety & Health Administration
OSPR	Office of Spill Prevention and Response
OSRO	Oil Spill Response Organization
OSRP	Oil Spill Response Plan
OSRV	Oil Spill Response Vessel
P&ID	Piping and Instrumentation Diagrams
PA	Public Address
PFD	Process Flow Diagram
PHA	Process Hazard Analysis
PLC	Programmable Logic Controller
PM	Preventive Maintenance
PPE	Personal Protective Equipment
PPM	Parts per Million
PRC	Public Resources Code
PROS	Professional Reliable Oilfield Services
PSH	Pressure Safety High
PSHL	Pressure Safety High-Low
PSI	Pounds per Square Inch
PSL	Pressure Safety Low
PSM	Process Safety Management
PSSR	Pre-Startup Safety Review
PSV	Pressure Safety Valve
ROE	Radius of Exposure
RP	Recommended Practice
SAC	Safety Analysis Checklist
SAFE	Safety Analysis Function Evaluation
SAMS	Safety Assessment of Management Systems
SCBA	Self Contained Breathing Apparatus
SDS	Safety Data Sheet
SEMS	Safety and Environmental Management Systems
SMP	Safety Management Programs
SOP	Standard Operating Procedures
SPCC	Spill Prevention Control & Countermeasure
TEC	Technical

UV/IR	Ultraviolet/Infrared
UPS	Uninterruptable Power Supply
Unocal	Union Oil Company of California
USCG	United States Coast Guard
UT	Ultrasonic Thickness
UV	Ultraviolet
V	Volt
VFD	Variable Frequency Drive

Appendix B
Best Practices and Regulations

<u>Regulatory References</u>

MRMD – California Code of Regulations (CCR) Title 2
CalGEM – CCR Title 14
Cal/OSHA – CCR Title 8
EPA – Code of Federal Regulations (CFR) Title 40
OSHA – CFR Title 29
USCG – CFR Title 33
BSEE – CFR Title 30 Part 250

1.0	**INTRODUCTION**	
1.1	Best Achievable Protection/ Best Achievable Technology	PRC 8750
	Inspection of Marine Facilities	PRC 8757
	Commission Oil & Gas Regulations	MRMD Articles 3 - 3.6
2.0	**FACILITY CONDITION AUDIT**	
2.1	Goals and Methodology	
2.1	General Facility Conditions	
	2.1.1 Workplace Housekeeping	MRMD 2129 & Cal/OSHA 6539
	2.1.2 Stairs, Walkways, Gratings, & Ladders	Cal/OSHA
	2.1.3 Escape/ Emergency Egress/ Exits	Cal/OSHA 3215 & 6577
	2.1.4 Labels, Color Coding and Signs	Cal/OSHA & API RP 14J
	2.1.5 Security	MRMD 2122
	2.1.6 HAZMAT Handling & Storage	OSHA 1910.1200
2.2	Field Verification of Plans	
	2.2.1 Process Flow Diagrams (PFDs)	MRMD 2132(a)(2) & API RP 75
	2.2.2 Piping & Instrumentation Diagrams	MRMD 2132(a)(2) & API RP 75
	2.2.3 Fire Protection Drawings	MRMD 2132(g)(4)(G) & API RP 75
2.3	Condition and Integrity of Major Systems	
	2.3.1 Piping	MRMD 2129(b) & (c); Cal/OSHA 6533; OSHA 1910.106(c)(4); API 570; ANSI B31.3
	2.3.2 Tanks	MRMD 2129(c); API 650 & 653
	2.3.3 Pressure Vessels	MRMD 2129(b) & (c); ASME Boiler & PV Code Sect. VIII; API 510 & RP 572; Cal/OSHA 6551(c)
	2.3.4 Relief Systems	MRMD 2132(g)(3); API RP 14J, 520, 521 & 576
	2.3.5 ESP, Pump Units & Wellhead Equip.	MRMD 2132(a)(4)
	2.3.6 Firefighting Detection Systems	MRMD 2132(g)(4); NFPA 25 & 72
	2.3.7 Firefighting Equipment	MRMD 2132(g)(4); NFPA 20 & 25
	2.3.8 Emergency Shutdown System (ESD)	MRMD 2132(g)(1) & API RP 14J
	2.3.9 Safety & Personal Protective Equipment	Cal/OSHA
	2.3.10 Instrumentation, Alarm and Paging	MRMD 2132(g)(1) & (2); API RP 14J
	2.3.11 Auxiliary Generator / Prime Mover	MRMD 2132(g)(7)
	2.3.12 Spill Containment	MRMD 2139 & 2140; EPA 112.7(c); California Government Code 8670
	2.3.13 Spill Response	MRMD 2139 & 2140;

		California Government Code 8670
2.4	Mechanical Integrity/Preventive Maintenance	MRMD 2129(c) & API RP 75
2.5	Production Safety Systems	MRMD 2129(b) &(c); API RP 14C, 14J, & 75; CalGEM 1747

3.0 ELECTRICAL SYSTEM AUDIT

3.1	Goals and Methodology	
3.2	Hazardous Area Electrical Classification Dwgs. • *Level of classification* • *Extent of classification*	API RP 500 & NFPA 70
3.3	Electrical Power Dist. System, Normal Power	API RP 540 & NFPA 70
	3.3.1 *Electrical Single Line*	
	3.3.2 *Electrical Service Capacity*	
	3.3.3 *Electrical System Design*	
3.4	Elec. Power Equip Condition and Functionality	API RP 540 & NFPA 70
	3.4.1 *Equipment Condition*	
	3.4.2 *Safety Procedures*	
	3.4.3 *Equipment Maintenance Practices*	
3.5	Grounding	API RP 540 & NFPA 70
3.6	Emergency Electrical Power	NFPA 70 & NFPA 110
	3.6.1 System Configuration	
	3.6.2 Equipment and Component Ratings	
3.7	Electric/Diesel Fire Pumps	NFPA 20 & NEC 696
3.8	Process Instrumentation	API RP 540 & NFPA 70
3.9	Lighting Systems	CalGEM 1743 (a)-(c); IES RP 7
3.10	Special Systems	CalGEM 1743 & 1747; API RP 14J, 75; Cal. Government Code 8670; ISA RP 7.1, RP 12.1, 12.2 ISA S7.4, S12.4
	3.10.1 Safety Control Systems	*Special systems codes above*
	3.10.2 Gas Detection Systems	MRMD 2132(g)(5); CalGEM 1747.6; API RP 14J
	3.10.3 Fire Detection Systems	MRMD 2132(g)(4); CalGEM 1743 & 1747 API RP 14J, 75, & 2001
	3.10.4 Aids to Navigation	USCG Subchapter C, Part 67
	3.10.5 Communication	USCG Subchapter C, Part 67
	3.10.6 General Alarms	USCG Subchapter C, Part 67
	3.10.8 *Cathodic Protection*	API RP 651, NACE RP 01-76, NACE RP 06-75

4.0 SAFETY MANAGEMENT PROGRAMS

4.1	Goals and Methodology	API RP 75
4.2	Operations Manual	PRC 8758
4.3	Spill Response Plan	Cal. Government Code 8670
4.4	Training and Drills	MRMD 2132; Cal/OSHA 6507;

		API RP 75
4.5	Safety Management Programs	Cal. Government Code 8670; EPA 112.7; API RP 75

5.0 SAFETY MANAGEMENT PROGRAMS

5.1	Goals of the Human Factors Audit	
5.2	Human Factors Audit Methodology	MRMD 2129(b) & (c); Commission Safety Audit of Management Systems (SAMS); API RP 75; BSEE Subpart S

Appendix C
References

GOVERNMENT CODES, RULES, AND REGULATIONS

CCR — CALIFORNIA CODE OF REGULATIONS

Title 2, Division 3, Chapter 1. State Lands Commission

2102-2175	*Sections of particular interest in Safety and Oil Spill Prevention Audit*
2129	*General Provisions, including references to “all applicable laws, rules, and regulations of the United States and the State of California” and “good oilfield practice”.*
2132	*Production Regulations*
2132(a)	*Well Completion*
2132(g)	*Production Facility Safety Equipment and Procedures*
2174	*Operation Manual Review*
2175	*Operation Manual Content*

Title 8, Division 1, Chapter 4. Division of Industrial Safety [Cal/OSHA]

3210	*Guardrails at Elevated Locations*
3212	*Floor Openings, Floor Holes, Skylights and Roofs*
3220	*Emergency Action Plan*
3308	*Hot Pipes and Hot Surfaces*
3340	*Accident Prevention Signs*
3944	*Guard Clearances*
5162	*Emergency Eyewash and Shower Equipment*
6533	*Pipe Lines, Fittings, and Valves*
6551	*Vessels, Boilers and Pressure Relief Devices*
6556	*Identification of Wells and Equipment*

Title 14, Division 2, Chapter 4. Development, Regulation, and Conservation of Oil and Gas Resources [CalGEM]

1742	*Well Identification*
1777	*Maintenance and Monitoring of Production Facilities, Safety Systems, and Equipment*

CFR — CODE OF FEDERAL REGULATIONS

29 CFR	*1910.144 Safety Color Code for Marking Physical Hazards*
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	*Process Piping*
Z358.1	*Emergency Eyewash & Shower Standard*
API	AMERICAN PETROLEUM INSTITUTE
RP 2A	*Planning, Designing, and Constructing Fixed Offshore Platforms*
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 55	*Oil and Gas Producing and Gas Processing Plant Operations Involving Hydrogen Sulfide*
RP 75	*Safety and Environmental Management System for Offshore Operations and Assets*
RP 500	*Classification 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 INTERNATIONAL SOCIETY OF AUTOMATION

5.1	*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

RP 01-76	*Corrosion Control of Steel Fixed Offshore Structures Associated with Petroleum Production*

NFPA NATIONAL FIRE PROTECTION AGENCY

20	*Stationary Pumps for Fire Detection*
24	*Installation of Private Fire Service Mains and Their Appurtenances*
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

110.12	*Mechanical Execution of Work*
110.22	*Identification of Disconnecting Means*
344.30	*Securing and Supporting Rigid Metal Conduit*
350.30	*Securing and Supporting Liquidtight Flexible Metal Conduit*
500	*Hazardous (Classified) Locations, Classes I, II, and III, Divisions 1 and 2*
501	*Class I Locations*
501.10	*Wiring Methods*
695	*Fire Pumps*

Appendix D
Team Members

FACILITY CONDITION TEAM

CSLC – MRMD	David Calderon Ryan Horton
DCOR – HB	Riston Francis Troy Kirby

ELECTRICAL TEAM

CSLC – MRMD	David Calderon Ryan Horton
P2S	Doug Effenberger
DCOR – HB	Chris Kenz

TECHNICAL TEAM

CSLC – MRMD	David Calderon Ryan Horton
DCOR – HB	Riston Francis Troy Kirby Martin Elu

SAFETY MANAGEMENT TEAM

CSLC – MRMD	David Calderon Ryan Horton
DCOR – HB	Riston Francis Troy Kirby