

Safety and Oil Spill Prevention Audit

DCOR, LLC
Fort Apache, Huntington Beach



California State Lands Commission

May, 2016

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Ft. Apache
Huntington Beach, CA

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Executive Summary

DCOR, LLC
Ft. Apache
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EXECUTIVE SUMMARY

Safety Audit of DCOR, LLC.'s Fort Apache

A Safety and Oil Spill Prevention Audit of the DCOR, Limited Liability Company (LLC.) Fort Apache (Ft. Apache), Huntington Beach onshore processing and shipping facility began in July 2014. Fieldwork was concluded in May 2015 with completion of the Electrical portion of the audit. Concurrent audits were also completed on Platforms Eva and Esther and those audits are each addressed by separate reports.

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

Company Background

Ft. Apache is owned and operated by DCOR, LLC, a privately owned company engaged in the development, exploration, and production of oil and natural gas in Ventura, Orange, and Los Angeles Counties. DCOR is a limited liability corporation with offices located in Ventura, California and Dallas, Texas. DCOR, LLC. was established in 2001 and incorporated in Texas. The company was formerly known as Dos Cuadras Offshore Resources, LLC. until the name was officially changed to DCOR, LLC. in July 2005.

Description of the Facilities

The Ft. Apache onshore facility is located in a residential area within the City of Huntington Beach, California. The facility is bounded by Heil Avenue on the south, residences on the east and west, and a storm drainage channel to the north. This onshore facility continuously receives gross crude oil from Platform Eva, arriving in an 8-inch steel subsea pipeline. The Ft. Apache facility consists of an oil dehydration and water processing area, gas processing system, holding tanks for oil sales and processed water, oil shipping pumps, and associated pipelines. The facility processes approximately 1,430 barrels of oil per day (BOPD) and 730 barrels of produced water per day (BWPD). Because of the separation process on Platform Eva, the majority of natural gas used for blanket and fuel gas is supplied by the City. It is manned 24 hours a day, seven days a week and safeguarded with 10 foot high block walls and secure fencing. The facility is designed with containment dikes and is sloped to retain potential oil releases.

Safety Audit Results

The Safety and Oil Spill Prevention Audit found that Ft. Apache complies with applicable safety and regulatory requirements and that an adequate level of safety and environmental protection has been achieved for facility activities. The established safety culture also ensures the protection of workers, the public and the environment.

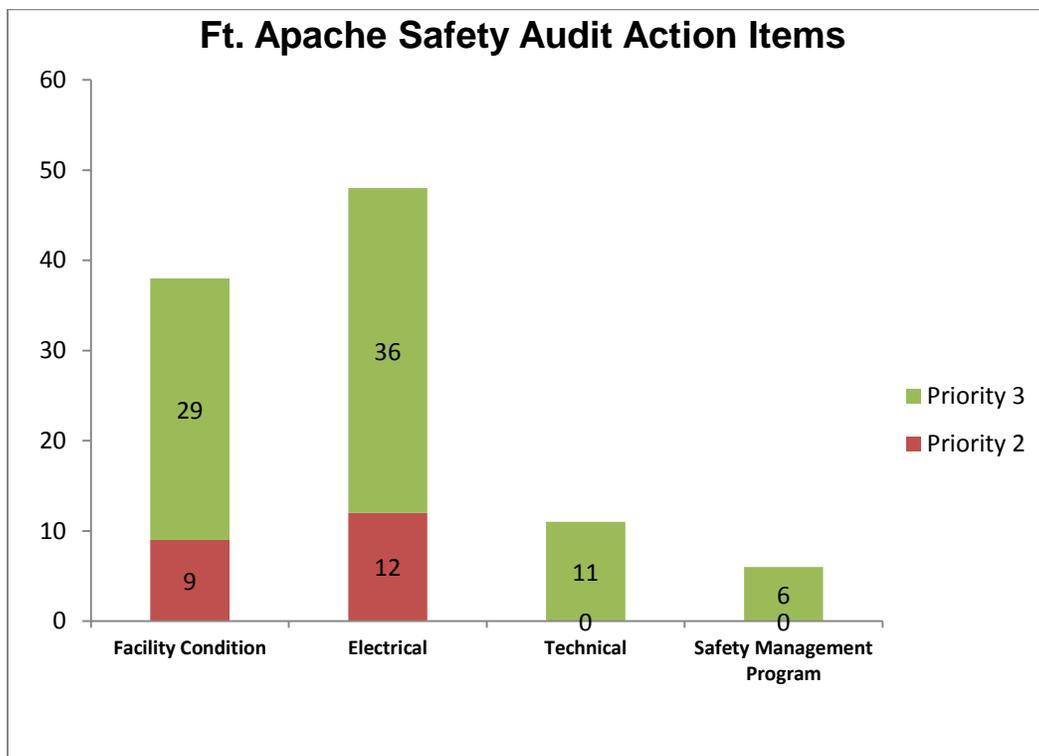
The condition of the facility was found to be in a generally appropriate state of repair, clean and well organized. DCOR, LLC. appears to have well established safety policies, health and environmental programs. A consistent safety and environmental culture has developed from

these programs. Employees are encouraged to participate and further enhance the overall reliability, job performance, and promote teamwork to reach organizational safety goals. Personnel are knowledgeable, and provided valuable assistance to the State Lands team with this safety audit.

Safety systems and equipment remain fit for service. However, a number of tanks and pressure vessels need internal inspections. Without inspection and condition assessment verification protocols, the equipment or system may not meet the intended requirements under operating conditions. Risk reduction and environmental compliance can only be ensured through scheduled inspections, testing, and preventive maintenance practices.

Firefighting and other emergency and spill response equipment were observed to be well maintained and in good operational condition. Company safety programs, such as personal protective equipment, are in place and functioning. The facility process control and safety shutdown systems have been upgraded and demonstrate satisfactory design, installation and maintenance following applicable codes and standards.

As described in the Action Item Chart that follows, the 2014 Safety and Oil Spill Prevention Audit revealed an increase in action items from the 2009 audit. The majority of these action items were identified as a result of recent electrical and mechanical upgrades. The upgrades require some additional features or components for proper installation, yet most are considered low risk. The action items are categorized into four subject areas.



The current audit identified 103 action items as compared to the 57 identified during the previous 2009 audit. In both audits, there were no priority one items that posed a high or immediate risk to personnel, the facility or the environment. The number of priority 2 action items increased from 10 to 21, and priority 3 items increased from 47 to 82 items. Priority 2 action items pose a moderate risk potential while priority 3 items pose a low risk potential. Resolution of priority 2 action items is required within 120 days, and resolution of the priority 3 actions items is required within 180 days after the report is issued.

The chart displays the nature of the action items as identified by the subject matter teams. This distribution is similar to other facilities in California where the items identified are typically related to piping, equipment, electrical systems, or condition and maintenance. Despite the increase in action items, DCOR appears to be committed to further risk management efforts for both facility and personnel safety, and to optimize safety management program strategies.

Introduction

DCOR, LLC
Ft. Apache
Huntington Beach, CA

1.0 INTRODUCTION

1.1 Safety Audit Background

The California State Lands Commission (CSLC) 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. CSLC sponsored safety audits ensure oil and gas production facilities on State leases or granted lands are operated in a safe and environmentally sound manner and comply with Federal, State, and Local codes or permits, as well as industry standards and practices. CSLC staff is tasked with oil spill prevention in California's ocean and tidelands, prevention of waste, conservation of natural resources, and ensuring that safety and health standards are being met. Public Resources Code (PRC) 6103, 6108, 6216, 6301, 6873(d), 8755 and 8757 provide authority for CSLC regulations as well as the existing inspection and 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. The Act also gave the CSLC certain authority over marine terminals. Under the legislation, marine facilities must provide the best achievable protection of the coast and marine waters.

Frequent monitoring and inspections of onshore and offshore oil and gas drilling and production facilities ensure that best achievable protection is in place to safeguard the public and environment. The Safety Audit Program, in conjunction with the CSLC's inspection program, helps prevent oil spills and other accidents with on-site inspection and verification activities. The Safety Audit Program also aids prevention through review of facility design, maintenance, human factors, and other aspects of safety management.

During a Safety and Spill Prevention Audit, audit team members systematically assess an organization's facilities, safety management programs, identify action items to be addressed, and provide feedback for improvement in a formal written report. Their areas of emphasis include:

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

Appropriate company contacts and resources are identified prior to the start of the audit. Progress and deficiency reports are communicated periodically throughout the audit process and an "action item matrix" is used to categorize and track action items. The matrix contains recommended corrective actions and a priority ranking for the specified corrective actions. A report highlighting the strengths and weakness of the facility is generated from the matrix items.

Draft copies of the report and the action item matrix are provided to the company frequently throughout the audit. The final audit report is presented to company management

formally, which affords the opportunity to discuss the findings and the corrective actions proposed in the final report. Throughout the clearance phase of the audit, the CSLC team continues to assist the operator in resolving the action items and tracks 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 in particular, oil spills. Previous experience shows safety assessments help increase operating effectiveness and efficiency, and lower operating cost. History has also shown that improving safety and reducing accidents makes good business sense.

1.2 Facility Background

1.2.1 Company History: The Fort Apache (Ft. Apache) facility began operation in 1963, as an asset of Union Oil Company. Nuevo Energy, a Houston based company, purchased Ft. Apache in conjunction with the purchase of Platforms Eva and Esther in April of 1996 from Unocal Oil. Nuevo Energy exclusively owned and operated the facility until May of 2004 when Plains Exploration and Production Company (PXP) took over after a merger with Nuevo Energy. PXP subsequently entered into a purchase and sales agreement with Dos Cuadras Offshore Resources (DCOR), a Texas based Limited Liability Company (LLC.), in September of 2004. This sale involved PXP assets including Platform Eva, Esther and Ft. Apache. The sale closed in December of 2004 with the approval of the lease assignment by the CSLC on October 20, 2005.

The company formerly known as Dos Cuadras Offshore Resources, LLC, officially changed its name to DCOR, LLC, in July 2005. DCOR's headquarters are based in Ventura, California. DCOR is owned entirely by Castle Peak Resources, LLC, a Texas based LLC, which in turn is owned by Crescent Resources, LLC, a California based company. All of these LLCs are 99% owned and controlled by Mr. William M. Templeton.

DCOR owns and operates eleven offshore platforms with a combined total California production of approximately 7,500 barrels of oil per day (BOPD). These include Platforms Esther and Eva in Orange County State Waters and nine other Platforms located off Santa Barbara and Ventura counties, in Federal Waters.

1.3 Facility Description

Ft. Apache is the onshore oil production processing facility that directly supports Platform Eva operations. Ft. Apache is located in the city of Huntington Beach, Orange County, California. The site is bounded by Heil Avenue on the south, residences on the east and west, and a storm drainage channel on the north. The facility is surrounded by ten foot high cement block walls and is accessible by two entrance gates, both front and rear of facility. The topography of the site is essentially flat. The facility separates water from the produced oil and prepares the oil for sale. Any produced gas is used for makeup gas and burned as fuel in the Heater Treaters along with city gas.

Ft. Apache has three active pipelines that enter or leave the facility. Processed crude oil from Platform Eva arrives at the facility via an 8-inch steel pipeline. Sales oil leaves the facility via a 6-inch steel pipeline owned by Crimson Pipeline Company to supply area refineries. Make-up gas used for blanking in tanks and vessels or used as fuel in the Heater Treater burners is supplied, as needed, from a 2-inch city gas supply line. The facility processes approximately 1,430 BOPD and 730 barrels of produced water per day (BWPD).

The operators control room is located on the south end of the facility next to the main entry gate. The facility is manned 24 hours per day, seven days a week and is monitored by both Platform Eva and Ft. Apache personnel. DCOR employs approximately twenty personnel that provide support with operation, maintenance, and administration duties between Platform Eva and Ft. Apache processing and shipping operations. Visitor and contract personnel attendance at Ft. Apache varies based on facility operations and maintenance plans.

1.3.1 Oil Processing: Gross oil production arrives via an 8-inch steel pipeline from Platform Eva. The oil flows to the inlet vessel separator known as the Free Water Knockout (FWKO), V-5, where excess water and natural gas are separated from the crude oil. The oil is transferred by process piping to Heater Treater vessels HT-2, HT-3, and HT-4 for further separation and dehydration. Sales oil leaves the Heater Treater units and flows to the Crude Oil Shipping Tank, T-4. The oil is then metered and sold through the Lease Automatic Custody Transfer Units and shipped through a 6-inch sales pipeline owned by Crimson Pipeline Company. Daily oil sales may fluctuate depending on pipeline carrier's schedule.

1.3.2 Water Processing: The produced water separated from the FWKO, V-5, is combined with the water separated from vessels HT-2, HT-3, and HT-4. The collective produced water flows to the Waste Water Vessel, V-1, where residual oil is skimmed off and sent back to the upstream side of FWKO, V-5. Waste water from V-1 is transferred to the Produced Water Tanks, T-1 and T-2, for treatment and subsequent release into the city sewer system. The permitted wastewater average per day is approximately 30,000 gallons from tanks T-1 and T-2, which are both metered, and discharged into the Orange County Sanitation Districts sewer line along with any surface water runoff. The wastewater contains less than (100) milligrams/liter of oil/grease and is processed through a clarification agitation system (Sparger Unit) prior to sewer discharge. This process has been approved by the City Sanitation and local Fire Departments. Water sample quality and testing are performed for analysis quarterly by both the City of Huntington Beach and third party contractor Positive Lab Company.

1.3.3 Gas System: Natural gas recovered from all vessels is routed to Blanket Gas Scrubber, V-10, then to the Vapor Recovery Compressor Suction Scrubber, V-11. The Vapor Recovery Compressor, CAE-1A, supplies gas to be used first as Blanket Gas to the vessels and secondarily through Fuel Gas Scrubber, V-9, as fuel gas for the burners on Heater Treater HT-2 and HT-3. A 2-inch city supply line provides make-up gas, as needed, to the system and also directly provides fuel gas for the burners on HT-4. A second Vapor Recovery Compressor, CAE-1B, is available on standby, and only operates when there is a loss of vacuum. Any excess gas that is in the system is routed to the Heater Treater burners.

Facility Condition Audit

DCOR, LLC
Ft. Apache
Huntington Beach, CA

2.0 FACILITY CONDITION AUDIT

2.1 Goals and Methodology

The primary goal of the Facility Condition Audit Team was to evaluate the current maintenance and integrity of DCOR, Limited Liability Company's Fort Apache (Ft. Apache) process facility. The on-site inspection involved a systematic evaluation of the systems, equipment, and facilities using checklists and methods that the team has developed over years of auditing. A variety of codes and standards apply in addition to California State Lands Commission regulations. Initial tasks to accomplish this goal included field verifications of key drawings/plans, condition inspection and evaluation of the facility, a review of system and equipment maintenance histories, further evaluation of key systems and equipment using checklists, and technical review of the safety system design. The layout of the audit report is generally "system by system" and includes a description and assessment of the facility with any significant observations. The report addresses safety of personnel as well as facility or process safety. The assessments of both areas of safety are important when identifying an organization's current level of safety development.

2.2 General Facility Conditions

2.2.1 Workplace Housekeeping: Facility work areas were clean and orderly, free of slip and trip hazards, waste materials (e.g., refuse, oilfield wastes) and fire hazards. There was an adequate supply of clearly marked refuse containers throughout the facility and all refuse appeared to be well controlled. Regular collection of waste is considered to contribute to good housekeeping practices. Employee facilities are adequate, clean, and well maintained. The washroom is cleaned frequently and has a good supply of soap and hand towels. The facility was found to be in satisfactory condition with no obvious health concerns.

Drip pans and splashguards are used throughout the facility to prevent spills and pollution. If a substance accidentally drips onto the ground, personnel clean it up immediately. Absorbent materials are stored in an emergency shed located next to the Supervisors office. They are readily available for wiping up greasy, oily or other liquid spills. Tools are available and stored in suitable fixtures for easy access. Tools are promptly 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: Stairs, walkways, gratings and ladders throughout the facility appeared to be of a safe design and construction. Safeguards were in place wherever there was a need to transition between levels and for routine access to equipment. The 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. Portable ladders and other necessary work equipment appeared in good working order and free from oil and grease. Fixed metal ladders and appurtenances were painted to resist corrosion. DCOR's safe work practices cover the use and care of ladder equipment on the facility.

2.2.3 Escape / Emergency Egress / Exits: Emergency exits, escape routes and gathering points are clearly posted and easily accessible. Evacuation routes are explained during initial worker orientation, safety meetings, and are reviewed as part of the work permit system. They are clearly identified with signs posted throughout the facility. Due to the design, size, and open arrangement of equipment inside the facility, there were no areas of concern regarding access and egress.

2.2.4 Labeling, Color Coding and Signs: The design, application, and use of signs and symbols within the facility define specific workplace hazards. DCOR adheres to Occupational Safety and Health Administration and American National Standards Institute recommendations. All employees receive instruction on what the signs mean and what, if any, special precautions are necessary to perform their task safely. Workplace hazards (e.g., slip, trip) are marked in yellow, and fire safety equipment is marked in red.

Required signs, including owner/operator contact information, were posted at the entrance and where needed within the facility. They were clearly visible and identified safety hazards. Tanks and vessels within the facility were clearly identified as confined spaces with warning placards posted at manways to warn personnel of potential hazards.

Fire diamonds were visible on all tanks, vessels, buildings, and chemical storage totes. The posting of fire diamonds is an indication of good facility emergency planning and conformance with the Uniform Fire Code.

2.2.5 Security: Physical and operational security measures are in place to prevent unauthorized entry into Ft. Apache. The facility is manned twenty-four hours a day, seven days a week with at least one operator present at all times. Fencing, facility lighting, locked doors, and an electronically controlled gate at the main entrance is used as a deterrent to unauthorized entry and vandalism. Facility personnel also provide additional monitoring with their normal operational surveillance. Operations management software (Wonderware) also provides Platform Eva personnel with a display of Ft. Apache's plant status and alarms.

2.2.6 Hazardous Material Handling and Storage: Flammable and combustible liquids were properly stored in safety cans and drums in accordance with California Occupational Safety and Health Administration and National Fire Protection Association 30 regulations. The bulk chemical totes were correctly labeled, appeared structurally sound, and had adequate containment in the event of a leak. No loose combustible material or empty drums were left on the premises.

Compressed gas cylinders were properly secured and legibly identified the gas content. Empty and unused cylinders had closed valves with protective caps in place. Cylinders were kept and safeguarded to prevent them from being knocked over or damaged.

Material Safety Data Sheets containing information on all chemicals used in the workplace were up-to-date and accessible to all personnel.

2.3 Field Verification of Plans

2.3.1 Process Flow Diagram (PFD): PFD's are considered an integral part of the design documentation for a facility. The PFD for Ft. Apache showed the correct flow through the plant processes, although some minor pieces of equipment were not shown. The drawing displayed the information typically included in a PFD, but the material balance sheet appeared to be outdated and should be examined and revised. (EFI - 2.3.1.01)

2.3.2 Piping and Instrumentation Diagrams (P&ID): A comprehensive field verification of P&IDs was performed for the process facility. The drawings were well organized and complete. The majority of drawings provided were accurate with only a few minor exceptions due to recent operational changes. A number of action items were generated as a result. (EFI - 2.3.2.01 thru 09)

2.3.3 Fire Protection Drawing: The fire protection drawing was mostly accurate with only minor updates or corrections needed. The drawing shows important information about the fire-fighting system including the firewater pump and source of fire-fighting water. It also includes the distribution system, location of main valves, stationary monitors, hose reels, portable fire extinguishers, safety showers and eyewash stations.

2.4 Condition and Integrity of Major Systems

2.4.1 Piping: An external visual inspection was performed to evaluate the mechanical integrity and maintenance of the piping in conjunction with the Piping and Instrumentation Diagram verification. This visual inspection and evaluation work observed the external condition of the piping, coating, signs of misalignment, temporary repairs, vibration, and leakage. The evaluation also included the condition of pipe hangers and supports as well as any field modifications not recorded on the piping drawings. The evaluation considered other key information such as material selection, piping design and maintenance practices.

DCOR uses a combination of ongoing routine and risk based piping inspections to achieve a desired level of facility safety, environmental protection, and prevention of unscheduled downtime. Inspection frequencies are set up according to regulatory requirements and established guidelines, e.g., American Petroleum Institute Recommended Practice 570 and Department of Transportation pipeline inspections. Results from ultrasonic thickness measurements, inspections, repairs and other non-destructive examination methods are reviewed and recorded by the facility engineer. Inspection results are available upon request.

The fitness and maintenance of piping throughout the facility was found to be in generally good condition, compatible with the process, operating parameters and environment. There were a number of Priority 3 action items generated, mostly due to the lack of proper fixed pipe supports. (EFI - 2.4.1.01 thru 05)

The production pipeline entering and the sales oil pipeline leaving the facility have the highest safety and environmental consequences if failure or loss of containment should occur. The production pipeline from Platform Eva to Ft. Apache consists of an 8-inch steel subsea pipeline. The safety devices and condition of the incoming subsea pipelines are discussed in

more detail in the Platform Eva Safety Audit report. The sales oil pipeline leaves the facility via a 6-inch steel pipeline owned by Crimson Pipeline Company and is used to supply area refineries.

Shorter interval inspections and corrosion protection from an impressed current rectifier (cathodic protection) are measures that are used by DCOR to maintain pipeline integrity. There were no action items regarding the subsea pipelines.

2.4.2 Tanks: Facility tanks are subject to DCOR's written inspection and maintenance program. The maintenance program is designed to follow American Petroleum Institute 653 Tank Inspection, Repair, Alteration and Reconstruction, as well as other industry standards and state regulations. There are a total of fifteen tanks at Ft. Apache. Four of them are permanent steel process tanks while the remaining eleven include two drain pits and nine portable storage tanks ranging in size from 55 to 500 gallons. Externally all fifteen tanks appear to be in good condition. The Reclaimed Oil Skim Tank, T-3, was found to be not properly anchored to its foundation. (EFI – 2.4.2.01) There was no evidence of recent damage or active leaks with any of the tanks.

A comprehensive review of the tank inspection records was performed to assess the current maintenance condition. As a result, one Priority 3 action item was generated due to the lack of inspection information available for the Reclaimed Oil Skim Tank, T-3. Clarification is needed to help determine the internal condition of the tank. If no inspection information is available, then an internal inspection is recommended. (EFI - 2.4.2.02) The other three remaining tanks, are either new (replaced) or recently repaired. Produced Water Tank, T-2, (bolted tank) was replaced in October 2010, and Produced Water Tank, T-1, (bolted tank) was replaced in December of that same year. The Crude Oil Shipping Tank, T-4, (welded tank) had an internal inspection performed in June 2011. Because of the inspection, the tank was removed from service until all necessary repairs were completed.

The Crude Oil Shipping Tank, T-4, is compliant with California State Lands Commission regulations for alarm and shutdown safety devices. A high level in the tank will cause a shut-in of all oil and water processing. The design and capacity for secondary tank battery containment meets the Environmental Protection Agency's Spill Prevention, Control and Countermeasures requirements. The concrete containment system is impermeable to crude oil and provides the required containment. The various tank high and low level sensors are displayed on the facility process computers and alarms alert the operator to changing tank conditions.

2.4.3 Pressure Vessels: Ft. Apache has a variety of pressure vessels ranging from air receivers to fired type three phase separators. These pressure vessels are built in accordance with American Society of Mechanical Engineers (ASME) codes and have the appropriate controls and safety devices for their intended purpose. The audit team performed a visual examination to assess the general exterior condition of the pressure vessels and their maintenance history. This method detects specific problems such as external coating failure, corrosion, leaks, labeling, inadequate anchoring or foundations, required instrumentation and gaps in inspection frequencies. Visually the pressure vessels appeared to be in good condition with the exception of three vessels, the Wet Gas Scrubber, V-6, Vapor Recovery Blowcase, V-11A, and Lease Automatic Custody Transfer Unit, L-1. Three Priority 3 action

items were generated for these pressure vessels because of foundation and/or anchoring concerns. (EFI – 2.4.3.01, 02 & 19)

External vessel inspections are required at least every five years with internal inspections not to exceed every ten years using non-destructive examination techniques per American Petroleum Institute (API) 510 Pressure Vessel Inspection Code. DCOR provided electronic vessel records containing the manufacturer's data report (form U-1A), as well as the last internal, external and non-destructive inspection reports for Ft. Apache. According to the inspection records provided, the vessels are being inspected externally at least every five years.

Further analysis of the record data determined that internal inspection frequencies are not being achieved in accordance with API 510 guidelines for some of the vessels. Inspection recommendations, maintenance activities, and design information should be documented and recorded within the pressure vessels permanent record. A review of the records that were submitted found that several pressure vessels were missing U1-As and were well beyond their due dates for internal inspections. These vessels require a systematic plan or schedule for internal inspections. The inspections are needed to maintain these vessels in accordance with API/ASME vessel codes. As a result, nine Priority 2 and six Priority 3 action items were generated. (EFI - 2.4.3.03 thru 07 & 09 thru 18)

The facility pressure vessels and control systems were designed with sufficient safety devices and redundancy to prevent and/or isolate any unintentional release of flammable gas or liquid. Two levels of protection are provided against potential hazards and the system is designed to be "failsafe". This integrated detection and protection system senses and activates appropriate shutdown devices as a first level. Pressure relief valves provide the second level of protection. Additional spill protection is provided by containment and operator intervention as a means of responding to an undesirable event. This safety control scheme is considered sufficient and adequate for the safe operation of the process facility.

Recent pressure vessel upgrades have included the replacement of older pneumatic style controllers with new electronic level controllers on the Heater Treaters and Free Water Knockout. In addition, a new, more efficient electronic burner management control system was installed on Heater Treater #3. Some of these new upgrades have required alterations to the vessels. No construction and/or repair information was provided. (EFI - 2.4.3.03)

2.4.4 Relief System: The primary purpose of the pressure relief system is to ensure protection for facility personnel and equipment from overpressure conditions that may happen during process upsets, equipment failure, and external fires. The relief system serves the major process vessels and components while other relief devices may be located on smaller ancillary components. The relief system components were evaluated for installation, design, maintenance, and functionality. Relief system components that were evaluated included:

- Pressure safety valves (PSVs)
- Relief system piping
- PSV Blowdown Vessel
- Flame arrestors

A visual inspection of the system determined that all piping laterals and headers are arranged so that the outlet from each PSV does not form a liquid trap. Similarly, the sizing of the discharge piping and the relief manifold provide adequate relieving capacity and protection to the corresponding vessel(s) from overpressure. In addition, the Blowdown Vessel is designed for efficient vapor-liquid separation and prevention of liquid carryover. As with older installations, the relief valves and associated piping were sized for a much higher production rate than present.

Isolation valves are installed on the inlet lines to PSVs and on the outlet lines for ease of maintenance. They are used to isolate a relief valve for inspection, servicing, and repair while the facility is operating. Due to the critical nature of this safety system, these valves are locked or car sealed in the open position during normal operations. The inspection found these valves properly car sealed and/or locked open.

Flame arrestors are normally used in vent systems to prevent combustion from entering the vent from an external source. According to manufacturer recommendations, flame arrestors should be checked at least annually to see if the elements are clean. DCOR's computerized maintenance management system (Mainsaver) schedules an annual inspection of the flame arrestor on the PSV Blowdown Vessel, V-13. This annual inspection also includes the flame arrestors on Heater Treaters #2, 3 and 4.

The maintenance and servicing records for all PSVs comply with applicable regulations and recommended standards (e.g., American Petroleum Institute Recommended Practice 520, 521 and California Occupational Safety and Health Administration 6551). PSVs are tested and serviced by an outside contractor. The inspection frequency is normally every six months regardless of the service of the relief valve. Service records were in order with no action items identified.

2.4.5 ESP, Pump Units, Wellhead Equip. & Well Safety Systems: Ft. Apache processes produced fluids from Platform Eva. The facility has no production or injection wells on location.

2.4.6 Fire Detection Systems: California State Lands Commission regulations and other fire protection requirements include fire detection and alarm systems. These systems are intended to provide early warning, notification of a fire, and possible activation of fixed firefighting systems. The process area at Ft. Apache, where there is potential for a flammable liquid spill, is monitored using numerous methods. These methods include:

- Personal observation and surveillance
- Process monitoring equipment
- Ultraviolet/Infrared (UV/IR) flame detectors
- Fusible heat sensing detectors
- Smoke detector

The fire system at Ft. Apache is comprised of UV/IR fire-eye flame and fusible heat sensing detectors. In the event of a fire, the UV/IR flame detectors will alarm at both Ft. Apache and Platform Eva and activate the emergency shutdown for Ft. Apache. UV/IR flame detectors are provided around the Heater Treaters. They are located peripheral to the monitored area. This reduces nuisance alarms caused by foreign sources (i.e. distant welding,

flash photography, etc.) external to the facility. UV/IR flame detectors are tested monthly and records are maintained.

Fusible heat sensing detectors are strategically placed throughout the facility. If activated they will shutdown the facility, alarm at both Ft. Apache and Platform Eva, and activate the deluge system in the Heater Treater, Lease Automatic Custody Transfer and Vapor Recovery Compressor areas. In addition, facility personnel who observe a fire or an alarm may also manually initiate the fire suppression before automatic sensing devices respond. The heat sensing detectors and plug loops were visually inspected and found to be in good working order. The fusible plug system was pressurized, constructed of noncorrosive materials and in good condition. Records showed that DCOR technicians test the fusible plug system tri-annually.

A stand-alone smoke detector, located on the ceiling of the electrical control room, was found to be energized, free of excess dust and overall in physically good condition. Mainsaver records indicated that facility personnel visually inspect it on a routine basis and that it is tested (push button) monthly.

2.4.7 Firefighting Equipment: The primary firefighting system is required by the California State Lands Commission (CSLC) and local fire authority. The system consists of a main electric driven firewater pump, three hose stations, two stationary monitors, and twelve portable fire extinguishers. A four-inch city water main supplies suction to the firewater pump. The fire pump is a 200-gallon per minute at 65-psi (rated pressure) centrifugal pump, driven by a 15 horsepower electric motor. The electric firewater pump provides the sole source for onsite fire suppression. The facility relies on the City of Huntington Beach Fire Department for backup fire protection. The fire pump is located between the lab and the new control room, along the south perimeter wall. It is fed by the normal power system from Motor Control Center - 1 in the electrical control room at 480 volts.

From the fire pump, the firewater main line supplies an open head deluge system, stationary monitors, and hose stations that provide protection for the entire process facility. This system can be operated manually or can be started automatically by the fusible heat sensing detectors. The deluge system control and bypass switches and status lights are located on the main control panel. Testing of the primary firewater pump is performed weekly and the automatic spray systems are tested monthly as required by CSLC regulations. Test results are recorded and retained for comparison purposes as required by the National Fire Protection Agency (NFPA) 25, 5-4. The firefighting system appears to meet the minimum fire equipment requirements found in NFPA 11, 13, 15 and 20 guidelines.

Facility operators also visually check the other fire suppression equipment monthly. An outside contractor is used to conduct the required inspections and testing semiannually. DCOR maintains the required test/inspection records, and ensures that all personnel responsible for the use and operation of the fire protection equipment are trained in the use of that equipment. Refresher training for operating personnel is conducted annually.

A visual inspection of the firewater piping, hose stations and monitors found that they were in good condition with respect to paint, rust, or other damage. The pipe to soil interface had mostly minor corrosion visible. Fire loop supports, hangers and braces were secure and

undamaged. As a result of the inspection, two Priority 3 action items were generated. The first was due to a lack of deluge coverage over the newly installed Lease Automatic Custody Transfer Unit #1. (EFI - 2.4.7.01) DCOR management was notified and immediately installed the additional deluge coverage. Second was to inspect a small section of 3" firewater piping near the stationary monitor for the Crude Oil Shipping Tank, T-4, that appeared to be heavily corroded. (EFI - 2.4.1.01)

The two stationary water monitors in the processing area were also inspected. There was no evidence of any leaks and the nozzle range of motion was acceptable. As part of DCOR's maintenance program, pivot points on the monitor are regularly greased, ensuring proper operation in the event of a fire.

Currently all fire protection components and related safety systems have been approved and deemed adequate by the City of Huntington Beach Fire Department who has primary authority regarding firefighting requirements. A city fire department station is located less than one mile from the facility.

2.4.8 Combustible Gas and H₂S Detection Systems: Ft. Apache is not required and does not have fixed gas lower explosive limit (LEL) detectors. It also does not have Hydrogen Sulfide (H₂S) detectors because levels in the production stream are negligible. Four-way handheld monitors, capable of detecting H₂S, Carbon Monoxide, LEL and oxygen level, are available for operating personnel.

2.4.9 Emergency Shutdown System (ESD): An Emergency Shutdown System is part of the Emergency Support Systems that requires a combination of devices arranged to safely initiate a facility shutdown. 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.

Ft. Apache is equipped with both manual and automatic ESD features. There are six manual ESD stations strategically located throughout the facility in the following areas:

- #1 Operator's Office/Control Room
- #2 South Gate (main entrance)
- #3 Electrical Control Room
- #4 LACT Programmable Logic Controller (PLC) Panel
- #5 Touch Screen (field)
- #6 North Gate

The manual ESD stations are clearly numbered and easily identified in case of an emergency. The stations are hard wired to the control panel (CP-1) in the control room. In addition, the Ultraviolet/Infrared (UV/IR) fire-eye flame and fusible heat sensing detectors will also activate the ESD automatically if flames are detected. Relays in panel CP-1 are fail-safe type. The system is reset from a button on the control panel.

Manual ESD stations and UV/IR fire-eyes are tested monthly, and the fusible heat sensing detectors are tested tri-annually. This is required by California State Lands Commission and National Fire Protection Agency regulations to verify proper operation and

alarm annunciation. Test records are maintained at the facility and history indicates the system remains in good working order.

2.4.10 Safety and Personal Protective Equipment (PPE): DCOR has a written workplace safety program for identifying, evaluating, analyzing, and controlling workplace safety and health hazards. This program has systematic policies, procedures, and practices that are fundamental to creating and maintaining a safe and healthy working environment. DCOR prioritizes the importance of preventing occupational injury and illness over production.

DCOR regularly assesses the workplace to determine if hazards are present that require the use of PPE when engineering and administrative controls are not feasible or effective in reducing these exposures to acceptable levels. Hazards are communicated to the employees, appropriate PPE is selected, and workers are trained in its use. Employees were observed using appropriate PPE as required by company policy or where hazards are known to exist. PPE commonly used include hard hats, steel-toed boots, fire resistant clothing, hearing protection, safety glasses, and other specialty items like face shields, rubber gloves, aprons, and fall protection as needed.

2.4.11 Lighting: DCOR has implemented a “good neighbor” policy that entails turning off non-essential process area lighting that could be a nuisance to nearby residences. They have achieved this balance through combining general and local lighting by providing the minimum required light with general lighting, adjusting lighting levels and providing portable task lighting. Fixtures installed throughout the facilities appear to be placed in a manner that provides adequate lighting levels for safely performing tasks. Mounted incandescent fixtures, high-pressure sodium vapor lamps and newly installed light emitting diode fixtures provide the area lighting. This method of artificial light appears to conform to work area lighting and hazardous conditions requirements.

2.4.12 Instrumentation, Alarm and Paging: The process instrumentation and process control is currently evolving from pneumatic to digital through facility upgrades. The new process of production controls and instrumentation are part of a Digital Control System (DCS) that is connected to the operator’s control room by digital networks. Within the DCS, Programmable Logic Controllers are used to control and monitor the process equipment and instruments. Operations management software (Wonderware) provides the operator interface displaying plant wide activities and has the ability to 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 which can be used to improve process efficiency and plant performance.

The computer screens used to operate the facility are known as Human Machine Interfaces (HMIs). They are a simple graphic display that mimics the process on the operator’s consoles, typically located in the control room. The HMI display allows the operator to access information and control the process in an uncomplicated manner. Common operator actions possible from the displays include:

- Setpoint Change
- Mode (Auto or Manual)

- Output Change
- Trending
- Loop Tuning
- Alarm Management
- Report(s)
- Shutdown of Selected Processes

The integrated alarm systems give an audible and visual indication to alert the operator that an alarm has been activated. The visual indication is used for specific alarm identification and evaluation. Audible tones are different for each process. The difference in sound is used to help operators identify the origin of the alarm.

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

The facility instrumentation is tested, maintained, and calibrated on a regularly scheduled basis. Records are readily available and the device history can be tracked through Mainsaver. All local instrumentation (e.g., pressure gauges, temperature gauges and recorders) appeared to be properly maintained and in good operating condition. Design and logic of these systems is further addressed in the Production Safety Systems section of this report.

2.4.13 Auxiliary Generator / Prime Mover: There is no auxiliary generator located at Ft. Apache. In the event of a power failure, the facility is designed to shutdown in a safe manner. A new APC Symmetra LX Uninterruptable Power Supply (UPS) system provides the only emergency power to the facility. Critical system controls, alarms, communication and office lighting are powered from the UPS. The unit is located in the electrical control room and according to the display, it will provide a runtime of 13 hours and 48 minutes on a full charge with the current 4% load. Section 3.6 of the electrical (ELC) report addresses the UPS system in further detail.

2.4.14 Spill Containment: The secondary containment around tanks and fluid handling equipment is adequate for meeting the Environmental Protection Agency's Spill Prevention, Control and Countermeasures regulations. This spill containment system coupled with routine visual inspections by operating personnel reduces the consequences if a leak or rupture were to develop. The containment volumes provided by the spill containment walls were carefully reviewed. The assessment found that containment for the stock tank as well as for the pressure vessels is correctly sized to meet regulatory requirements. The containment volumes provided contain more than the volume of the largest tank plus the recommended allowance for precipitation while excluding the volumes occupied by other tanks.

2.4.15 Spill Response: Oil spill response for Ft. Apache is outlined in DCOR's Oil Spill Contingency Plan. The plan satisfies both federal and state regulations and is discussed in more detail in the Safety Management Programs section of this report. Spill response equipment identified in the plan is stored in an emergency shed located next to the Supervisors office. The shed is stocked with a variety of pollution control equipment including

spill booms and absorbent pads that meets the minimum requirements. Facility personnel are considered the primary responders in the event of a spill and are prepared to effectively cleanup small to moderate spills using the on-site response equipment. For larger spills, outside spill response companies are under contract to respond.

2.5 Preventive Maintenance and Mechanical Reliability

This preventive maintenance and mechanical reliability section provides a general overview of DCOR's corporate philosophy and approach to implementing a successful reliability program. Preventative maintenance and job scheduling is controlled by a software maintenance planner, Mainsaver. The maintenance planner reviews new workorders daily and assigns an in-house craft or outsources the task to a contractor/vendor depending upon workload and specific job requirement. The planner also stages commonly used parts and supplies while local contracted vendors supply critical spare parts. DCOR believes this provides them with maintenance task optimization and decreases the chance of equipment failure.

Mainsaver is also utilized to capture maintenance and repair activities. The system has the ability to plan, schedule, manage inventory control, and record maintenance activities. However, the maintenance module is not being used to its full potential for preventive maintenance. A lack of established frequency, details on the extent of inspections and missing equipment histories are areas that exhibit room for improvement.

DCOR has developed a risk management system to help address the reliability of their equipment including facility tanks, pressure vessels and piping that contain oil. The system uses regularly scheduled internal, external and ultrasonic inspections and repair information to assess risk. A risk level is established for the various pieces of equipment based on service and consequence of failure. When the risk level for a particular tank, pressure vessel or section of piping reaches an unacceptable level, the facility engineer is expected to implement a corrective or mitigating action to lower the risk level to an acceptable level. Due to the lack of tank and pressure vessel inspection information provided to us, it was unclear if this is fully occurring. (EFI - 2.4.2.02, 2.4.3.03 thru 07 & 09 thru 18)

A number of different methods are being used to preserve the life of the various plant equipment and systems that include:

- Primer, Paint and Tape Wrap Coatings (External)
- Epoxy Coatings (Internal)
- Cathodic Protection
- Chemical Treatment

Baker Hughes provides Ft. Apache with a chemical treatment program that satisfies the operational needs of the facility. A main component of the program is corrosion inhibitor. The chemical protects the internal surfaces 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.

Cathodic protection and sacrificial anodes are also used in conjunction with other forms of corrosion control such as protective coatings, wherever internal and/or external surfaces are exposed to aggressive environments. This means of corrosion control is provided for select pressure vessels, tanks and piping. Appropriate record keeping from regularly scheduled internal, external and ultrasonic inspections and repairs would help to provide historical data and signs as to the source of a detected deficiency.

An overall evaluation of the effectiveness of DCOR's maintenance management practices found that Ft. Apache is currently designed, operated, and maintained in a stable and reliable manner. There appears to be room for additional improvement to the preventive maintenance system so that fewer unanticipated repairs are needed.

2.6 Production Safety Systems

All safety devices and their functions were analyzed for regulatory compliance by comparing the Safety Analysis Function Evaluation (SAFE) chart and facility Piping and Instrumentation Diagrams. The comparisons matched all safety and shutdown devices, as well as, Emergency Support Systems, to their functions. The review determined that the SAFE chart is not current and in need of revision. (EFI - 2.6.01 thru 11) SAFE charts are necessary to evaluate the function of safety devices and to document what each safety device does. The chart also ensures that the facility is fully protected and can serve as a valuable troubleshooting tool.

Further analysis of facility drawings and Programmable Logic Controller (PLC) logic found that the design of process controls and safety systems are adequately documented and have the appropriate level of safeguards. Operational safety was found to be properly addressed through safe design features, hazard evaluation and risk assessment. The automated process control and safety systems appear to have been designed following applicable codes, standards and industry practices.

Plant status, controls and alarms for the process and safety systems are displayed in real-time via Human Machine Interface displays located in the field and control room. The automated control system, using a PLC for logic, monitors and controls the facility processes. These control systems minimize the effects of undesirable events and mitigate the consequences from operational upsets. When hazards cannot be eliminated or controlled through design, DCOR uses a hierarchy of health and safety controls (e.g., Administrative and Engineering Controls) to eliminate hazards or reduce exposure to hazards.

Facility production safety systems also include pressure safety high and low and level safety high and low devices on Free Water Knockout, V-5, temperature safety high devices on Heater Treaters #2, 3 & 4, level safety lows on Produced Water Tanks, T-1 & 2, and an level safety high on the Crude Oil Shipping Tank, T-4. These devices are all capable of shutting down the process. In addition, Ultraviolet/Infrared fire-eye flame and fusible heat sensing detectors located throughout the process facility have the same ability.

Electrical Systems Audit

DCOR, LLC
Ft. Apache
Huntington Beach, CA

3.0 ELECTRICAL SYSTEMS AUDIT

3.1 Goals and Methodology

The primary goal of the Electrical (ELC) Team was to evaluate the electrical systems and operations of the DCOR, Limited Liability Company onshore Fort Apache (Ft. Apache) facility to determine if it conforms to recognized and appropriate electrical codes and industry standards.

References used in review of facilities include documents published by the American Petroleum Institute (API), National Fire Protection Association (NFPA), the State of California Electric Code (CEC) and California State Lands Commission (CSLC) Regulations. The ELC Team review comments are based on those publications, which primarily include API RP 14F, API RP 500, API RP 540, CEC documents and industry standards. The drawings used in support of the audit were electrical single-lines and area classification drawings provided by DCOR for the facility.

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

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

3.2 Hazardous Area Electrical Classifications 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 diagrams are generally representative of the existing conditions and area class elements. However, the drawings do need to be updated to include process and equipment additions and deletions made since the last revision in 2009. (ELC - 3.2.04 thru 06)

The purpose of an electrical area classification drawing is to define the locations of boundaries and areas where specific electrical materials and installation practices are required to manage the explosive properties of flammable liquids, vapors and other volatile materials. Installation and maintenance of electrical systems requires attention to the type of hazard and the level of the hazard in order to insure compliance with CEC requirements. Electrical area classification drawings are required to include the information necessary for a qualified electrician to perform work in and around classified areas. DCOR drawing DCOR-FA-EL-C-0101 was last revised in October 2009 and requires an update. (ELC - 3.2.07)

Areas that contain walls, depressions and barriers to natural ventilation, where flammable liquids or vapors may be present, require evaluation and identification of the appropriate electrical area classification. All areas known to contain flammable liquids or vapors are required to be identified on an electrical area classification drawing. The area classification plans require additional details to more clearly define and illustrate the facility area class boundaries. (ELC - 3.2.07)

General-purpose electrical enclosures (load centers, motor control centers, control panels, etc.) are only suitable for use in unclassified areas. In general, electrical equipment installed in classified areas was found to be explosion proof, National Electrical Manufacturers Association (NEMA) 4, purged or otherwise suitable for use in classified areas. However, purged enclosures must have purge systems monitored and equipped with an alarm when purge pressures drop below a minimum level. (ELC - 3.2.02)

Some junction box and conduit fitting covers are missing or not properly seated against box flanges to provide adequate seal in classified areas. Covers must be flange-face to flange-face or box if bolt-on type or five full threads engaged if screw-cover type. (ELC - 3.2.03)

Conduit seals are required at classification boundaries. Locations where conduits originate outside of classified areas and travel through classified areas without the use of a box, fitting, or coupling may cross boundaries of Division 2 areas without a seal. Some equipment that is in the process of being added, relocated and/or repurposed requires seal-offs to be packed and poured prior to energization. (ELC - 3.2.01)

3.3 Electrical Power Distribution System, Normal Power

Utility service is supplied from an Edison overhead pole top transformer line and service drop consisting of pole line disconnects and three 50 thousand volt-amps (kVA), 4160-480 volt (V), single-phase transformers on a pole line structure adjacent to the facility.

The Edison supplied transformers provide 480V, three-phase, three-wire power to Ft. Apache via parallel runs of 3-1/C #750kcmil 600V cable routed in conduit to the main Service Switchboard (MS-1). This switchboard lineup includes a service entrance section consisting of a utility metering compartment and one main 1000 amp frame / 800 amp trip breaker, to supply power to the 480V motor control center (MCC) -1 lineup, and one main 600A circuit breaker to supply power to MCC-2. The main service has been reconfigured with the addition of MCC-1 and MCC-2.

3.3.1 Electrical Single-Line: The electrical single-line drawing DCOR-FA-EL-D-0100 was used for review of the facility electrical system. The drawing is no longer representative of the electrical power system and requires revision in order to adequately evaluate the power system, and to complete power system studies. (ELC - 3.3.1.01 & 02) The audit focused on power distribution systems 480V and above, and excluded the lower voltage systems. DCOR will need to add missing information and incorporate the corrected information into an updated single-line drawing.

3.3.2 Electrical Service Capacity: The normal power system capacity may be adequate based on present usage; however, the utility service transformer three-phase rating is 150kVA,

which may be close to the facility peak load. It is recommended that the serving utility be contacted regarding any service capacity and motor starting limitations and to determine the peak load. The utility provided information should be added to the facility single-line diagram. (ELC - 3.3.2.03) Electrical system utility short circuit duty data was not available to confirm equipment withstand rating and is required to be included on the single line diagram. (ELC - 3.3.2.04) The application of overcurrent devices with respect to equipment and conductor ratings is generally satisfactory.

3.4 Electrical Power Equipment Condition and Functionality

3.4.1 Equipment Condition: CEC 110-13, Mounting Electrical Equipment, requires all electrical equipment to be firmly secured to the surface on which it is supported. CEC Article 300-11, Securing and Supporting, requires all electrical raceways, cable assemblies, boxes, cabinets and fittings to be secured or fastened in place. Additional securing requirements are also provided in the CEC for individual types of installations and conditions. Securing and supporting of electrical equipment, cables and materials needs to be consistently maintained, repaired and managed throughout the facility. (ELC 3.4.1.06, 08, 10 & 11)

There were several openings in equipment noted such as missing cover plates in panelboards, gaps in equipment cover plates that would allow rodent nesting, and open conduits. The openings should be closed. (ELC 3.4.1.01, 04, 05, 09 & 13)

The electricians must follow a mandatory set of procedures designed to enhance personnel safety and reduce the potential for shock and injury. The safety procedures are documented in the Safety Procedures Manual, dated October 2013. Part 4.15 of the manual covers the Electrical Safety Policy. Electricians are responsible to complete a task checklist prior to beginning any work. The checklist includes identification of hazards that might be associated with the task and the measures to be employed to minimize the hazard, risks. It is recommended that the forms and checklists required to be completed prior to performing electrical work be included in the manual. (ELC - 3.4.2.07) The lockout/tagout program is well documented and implemented.

3.4.2 Equipment Maintenance Practices: DCOR uses Mainsaver software to track and generate maintenance work orders. The server for the Mainsaver database is located at a DCOR corporate facility and is used primarily as a scheduling program.

Reliability of the electric system is primarily dependent on the availability of the Southern California Edison (SCE) power supply in addition to the condition and operational readiness of the onshore facility distribution system. A sound maintenance and inspection program, properly implemented, is key to assuring the highest level of reliability. Electrical maintenance tasks are being managed by operating personnel through workorders. The Mainsaver system is not the primary source, or tool, being used. At the time of this assessment, there was an unidentified number of preventative maintenance backorders in the system.

In addition to Mainsaver generated workorders, corrective work orders are generated by personnel. Corrective work orders document field observations and are submitted to the Supervisors for review and implementation.

The 480V MCC-1 and MCC-2 are newly installed and no acceptance test or commissioning documentation was available at the time of the on site assessment. NFPA 70B, Recommended Practice for Electrical Equipment Maintenance, and International Electrical Testing Association (NETA) recommend visual inspection of switchgear every twelve months and electrical testing and calibration at thirty-six month intervals.

The CEC requires facility electrical equipment that is likely to be examined, adjusted or serviced while energized is marked to warn qualified persons of potential electric arc flash hazards. The labels installed are out of date and no longer comply with the revised NFPA 70E arc flash hazard label requirements. NFPA 70E recommends that the arc flash hazard study be reviewed and updated every five years or whenever electrical system modifications are made. The arc flash hazard study should be updated and arc flash hazard labels should be replaced. Review of The Safety Procedures Manual, Part 4.15, Electrical Safety Policy, revealed that Part 4.15 requires an update and revisions based on recent code and regulatory changes. (ELC - 3.4.2.07)

3.5 Grounding

CEC Articles 250 and 501 provide the requirements for power system grounding and bonding in oil production facilities. Significant portions of the requirements for grounding are established to prevent or reduce the possibility of injury to personnel from shock. The rules of grounding also contribute to reduction of equipment damage either from induced voltages or during fault conditions. The three types of grounding required at the facility are power system circuit grounding, equipment equipotential grounding, and static control 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. That is, ground circuit bonding shall be continuous from the load all the way back to the power transformer grounding electrode system. The best way to achieve ground circuit continuity is to include properly sized (CEC 250) equipment grounding conductors with each set of power conductors from the source of power to the load. (ELC - 3.5.01 & 03)

3.6 Emergency Electrical Power

3.6.1 System Configuration: The Uninterruptible Power Supply (UPS) provides power for critical control and communications systems. The APC Symmetra LX UPS unit feeds power strips in the new server rack and a new 120/240V panelboard located adjacent to the server rack to maintain power for the emergency systems listed below:

- Control Room computers and equipment
- General Alarm and Shutdown systems
- Allen Bradley PLCs and I/Os for process control and monitoring
- Communications system
- Fire eyes

3.6.2 Equipment and Component Ratings: UPS power is provided from a new APC Unit in the electrical control room. The APC Symmetra LX UPS is a packaged unit complete with batteries. The load is very low at 4% of capacity.

Battery capacity was not determined during the inspection. Full load battery capacity should be in excess of 4 hours. The UPS has expandable battery capability to extend runtimes. DCOR should confirm existing battery capability and determine that the 4-hour requirement is satisfied. (ELC - 3.6.01)

3.6.3 Electrical System Design Safety: No backup generator is provided for the facility. Critical system control, alarms and communication are powered from the UPS in the control room. An extended power outage would eventually drain the UPS batteries requiring a shutdown of the facility. It is recommended that provisions, such as a manual transfer switch for connection of a temporary generator, be provided. (ELC - 3.6.02)

3.7 Electric Fire Pump

A 15hp electric firewater pump is located between the control building and the front entry gate and supplied electricity by the normal power system from a 480V feeder in MCC-1. The electric firewater pump provides the sole source of pressurized water for onsite fire suppression. The deluge system control and bypass switches and status lights are located on the main control panel. The Ft. Apache facility relies on the local fire department for backup fire protection.

The present installation does not comply with CEC 695.3(A) for reliable firewater pump power source requirements. (ELC - 3.7.01) CEC article 695.3(A)(1) requires the firewater pump feeder to be supplied from a tap located ahead of the main breaker in order to be defined as a reliable source.

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, 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.

Two computers (PC) located in the control room provide operator interface to the process control system. The PCs are linked via Modbus+ to the new Allen Bradley PLC, and run the Wonderware software package. A second Allen Bradley PLC core processor is also located in the facility.

Programming for the PLC is resident on the PLC. In the event of a PLC processor failure, programming is available to upload from the PCs in the office. No formal written documentation has been provided to verify that a written procedure for management of change is in place to track changes to the programming or sequence of operations. (ELC - 3.8.01)

The Allen Bradley PLC located in the control board CP-1 in the control room effectively monitors and controls operations at the facility. Control and monitoring from the offshore platforms is provided through the spread spectrum radio system from the RTU on Platform Eva to an RTU located at the first street, Seal Beach facility.

3.9 Standby Lighting

Standby lighting was not included in this investigation.

3.10 Special Systems

The ELC Team review comments for special systems are based on API RP 540 Electrical Installations in Petroleum Processing Plants, and CEC documents.

3.10.1 Safety Control Systems: Safety control systems are required to be a combination of devices arranged to safely affect facility 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. There are six Emergency Shutdown (ESD) stations located throughout the facility, including the main control panel and at the North and South gates of the facility. Stations are hard wired to the control panel CP-1 in the control room. The stations appeared to be in good working order and are periodically tested.

Facility Production Safety Systems also include pressure safety high and low (PSH/L) and level safety high and low (LSH/L) devices on FWKO, V-5, temperature safety high devices (TSH) on Heater Treaters #2, 3 & 4, LSLs on Produced Water Tanks, T-1 & 2, and a LSH on the Crude Oil Shipping Tank, T-4. These devices are all capable of shutting down the process. In addition, Ultraviolet/Infrared (UV/IR) flame and fusible heat sensing detectors located throughout the process facility have the same ability. Relays in panel CP-1 are fail-safe type. The system is reset from a button on the control panel. ESDs are tested monthly, including fire-eyes, fusible heat detectors tri-annually, and testing records are maintained.

3.10.2 Gas Detection Systems: Combustible gas detection systems, LEL and H₂S type, 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. Ft. Apache does not have fixed gas LEL detectors nor is it required to have H₂S detectors because H₂S levels in the gas stream are negligible.

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

Fire-eye type UV/IR detectors are provided around the Heater Treaters. Fire-eye detectors are located on the periphery facing into the monitored area. This was done to reduce nuisance alarms caused by foreign sources (i.e. distant welding, flash photography, etc.) external to the facility. At the time of the inspection, the fire-eyes were bypassed because of maintenance being completed on one Heater Treater.

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

There is only one stand-alone smoke detector provided on the ceiling of the electrical control room. The unit appeared to be active, but was not tested during the inspection.

3.10.4 Aids to Navigation: Not applicable.

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. Communication equipment is located in the electrical control room as follows:

Incoming Service: Verizon phone service (Time-Warner is the service provider) is connected to a 10-base T hub located in the electrical control room.

Communications to the platforms: A dedicated T1 line departs Ft. Apache and extends via Verizon to the electric utilities company substation located on California Resources Corp., SoCal Holding Inc.'s facility at Goldenwest and Pacific Coast Highway in Huntington Beach. There the signal is routed through an Ethernet/Fiber Optic (FO) converter. The fiber optics cable routes in the submersible power cable to Platform Eva. At Eva, the fiber optic cable is separated from the power cables at the main interrupter switchgear in the switchgear room and routed through a FO/Ethernet converter to the platform Ethernet. A spread spectrum radio system links the telecom system at Eva to Platforms Esther and Edith. Communications equipment on Esther is powered through the UPS unit.

Ft. Apache is manned twenty-four hours a day, seven days a week with at least one operator present at all times. Remote monitoring and control of Ft. Apache can still be achieved from Platform Eva. Loss of the Verizon signal results in loss of control of Ft. Apache from Platform Eva.

A radio base station in the control room provides radio communication with the crew boat. This system and the other installed systems are also backed up by cellular phone.

3.10.6 General Alarms: General Alarms annunciate at the main control board.

3.10.7 Cathodic Protection: The production pipeline receives its protection against corrosion from an impressed current rectifier located outside the facility wall north of the Crude Oil Shipping Tank. A 30-amp fused disconnect protects the rectifier. The rectifier operation could not be verified. The production pipeline from Platform Eva to Ft. Apache consists of an 8-inch steel subsea pipeline. The safety devices and condition of the incoming subsea pipeline are discussed in the Platform Eva report.

Safety Management Programs Audit

DCOR, LLC
Ft. Apache
Huntington Beach, CA

4.0 SAFETY MANAGEMENT PROGRAMS AUDIT

4.1 Goals and Methodology

The goal of the Safety Management Programs Audit was to verify that DCOR, Limited Liability Company uses a set of related approaches to manage hazards and reduce the frequency and severity of undesirable events. DCOR's safety management programs are composed of organizational and operational procedures, design management, audit programs, and other methods defined by the Occupational Safety and Health Administration (OSHA) and Environmental Protection Agency (EPA). The Fort Apache (Ft. Apache) audit commenced with a review of the Operations Manual, Standard Operating Procedures, required emergency and spill response plans, training programs, and other key elements. These areas were reviewed before evaluating the other programs that are addressed in their Safety and Environmental Management Program.

4.2 Operations Manuals

Ft. Apache has an Operations Manual as well as Standard Operating Procedures (SOPs). Both manuals are reviewed by designated DCOR personnel annually with hard copies readily accessible in the operator's control room and office. DCOR is currently in the process of making electronic copies of their manuals and putting them on the company intranet.

The Ft. Apache Operations Manual was reviewed to determine whether or not it meets the content requirements outlined in Mineral Resource Management Division Regulation 2175. Basic requirements for an Operations Manual include location, purpose, ownership and responsibility. A comprehensive review determined that the Operations Manual met the required format outlined in 2175 and demonstrated compliance with operating rules and regulations. The Operations Manual was arranged in a logical order with clearly defined tabs for quick reference, a comprehensive table of contents and numbered pages. However, it was noted that some of the operating information does not appear to be current and/or up-to-date, including content regarding facility security, contact phone list, flow diagram, and text information. (SMP – 4.2.01 thru 03)

DCOR has a system in place for determining what procedures or processes need to be documented. Individuals knowledgeable with the process and its hazards write the SOPs. These individuals are familiar with the subject matter and typically have performed the work and operated the process. The SOPs are written in a concise, systematic, 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. The information presented in the operations manual was found to be accurate, clearly written, and not overly complicated.

4.3 Spill Response Plans

The DCOR, Ft. Apache Oil Spill Contingency Plan (OSCP) was developed under Federal and State Facility Response Plan requirements. The document defines specific procedures and plans for responding to discharges of oil into navigable waters and seeks to minimize damage to the environment and neighboring community. It identifies the resources

needed to implement the plan and communicate relevant information needed to respond to a spill in a clear, concise and easy-to-use format to manage containment, cleanup, and mitigate the effects of an oil spill.

The OSCP was reviewed and noted to have a structured approval process assessed by DCOR's management team. It meets Federal (40 CFR Section 112) and State Office of Spill Prevention and Response (OSPR) compliance requirements. Ft. Apache staff is familiar with the OSCP and holds semi-annual spill drills by means of different scenarios to test the effectiveness of their spill response plan. DCOR's Business Emergency Plan (BEP) is approved by the Huntington Beach Fire Department. This document appears to meet the Hazardous Materials Disclosure Program requirements of the city.

4.3.1 EPA Spill Prevention Control and Countermeasure (SPCC): The SPCC Plan is an EPA requirement. A hard copy version of the plan was reviewed for compliance and appears to meet the EPA Rule. However, there were a few minor concerns regarding some operating information that appeared to be outdated, including contact information, equipment and condition changes, and text information. (SMP - 4.3.1.01) The plan is prepared in accordance with good engineering practices. It provides engineering, operation, maintenance, and management strategies to lessen the potential of a spill or release of oil products (e.g. fuel and petroleum/lubricating based oil/product) from certain storage and operational equipment and activities, and in the event of a spill, to prevent the spill from entering a navigable waterway or neighboring community. The plan is approved by management and certified by a licensed professional engineer.

4.4 Training and Drills

DCOR has a qualification training matrix program for new employees and ongoing training that includes optional and compulsory training for all personnel. DCOR uses a combination of class room and online computer based training known as Petro-Skills and Compliance Services to alert personnel to upcoming training requirements and maintains a history of all training activities.

Mandatory training that is conducted to satisfy OSHA and spill response requirements include: Hazardous Communications, Personal Protective Equipment (PPE), Incipient Firefighting, Control of Hazardous Energy (Lockout/Tagout), Confined Space Entry, Hot Work, Respiratory Protection, Hydrogen Sulfide (H₂S), First Aid/CPR Medic Inclusive, Work Authorization Permitting, Hazardous Waste Operations and Emergency Response (HAZWOPER), Department of Transportation Pipeline Operations, Oil Spill Drills, and Process Safety Management.

The facility operations qualification training program 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 uses a strict testing and competency demonstration evaluation method. Both the lead operator and staff supervisor must sign off on the training and qualification. Next level promotion is based on progression through these operating requirement elements and DCOR's Human Resources approval. Situational awareness training helps employees recognize abnormal operating conditions as well as what to do in the event of an incident.

Spill response team members receive training to perform the tasks required of them based on their job description and responsibility. This training consists of classroom instruction, field briefings, tabletop and equipment deployment drills. Exercises, safety meetings, evacuation and environmental training are held throughout the year. Oil spill drills enable response personnel to become knowledgeable and skillful in the plans and to expose any weaknesses in procedures. If DCOR finds significant deficiencies in the spill plan as a result of a drill or exercise evaluation, the company will record those deficiencies and require specific changes to the plan. Plan revisions may require additional inspections, drills, and training to take place.

DCOR's Training Administrator maintains employee training and drill records for availability to regulatory agencies upon request. DCOR's training program appears to meet all requirements for safety management systems and spill response. No action items were identified.

4.5 Safety Management Programs

A DCOR corporate Safety Management Program (SMP) that parallels the OSHA Process Safety Management (PSM) standard is used to control workplace hazards. While the Ft. Apache, Huntington Beach facility is not currently subject to OSHA PSM regulations, DCOR management has stated that they have voluntarily integrated their corporate SMP into the facility. Recent facility upgrades have revealed that they could improve on inconsistencies regarding documents pertaining to compliance inspections of processing equipment, management of change evaluations, and the frequency and implementation of self-audit practices. Despite the few inconsistencies, it does appear as though the programs have been implemented and are helping to reduce incidents involving the release of hazardous materials beyond the facility boundaries.

DCOR's safety policy sets a clear direction for the organization to follow and is part of established business performance goals and commitment to continuous improvement. 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 approved its safety policy. Safety management roles within the organization are coupled with the safety of their personnel. This association is shown in the planning, and carrying out of DCOR's safety policy. Management audits and reviews the performance of SMPs.

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

Human Factors Audit

DCOR, LLC
Ft. Apache
Huntington Beach, CA

5.0 HUMAN FACTORS AUDIT

5.1 Goals of the Human Factors Audit

The primary goal of the Human Factors team is to evaluate the operating company's human and organizational factors by using the Safety Assessment of Management Systems (SAMS) interview process. The California State Lands Commission (CSLC) SAMS team conducts interviews with a cross-section of company and contractor personnel, from which an assessment of the level of Safety Management Program integration and level of maturity of safety culture is derived. The SAMS is planned to be conducted following audits of the DCOR, Limited Liability Company facilities. Interview results are considered confidential between CSLC and DCOR and will be contained in a separate report.

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

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

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

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

5.2 Human Factors Audit Methodology

The CSLC Mineral Resources Management Division (MRMD) has conducted the SAMS interviews with DCOR staff and sub-contractors after completing the safety and oil spill prevention audit. Interview responses are being evaluated according to SAMS guidelines and a separate confidential report summarizing the results will be generated. The MRMD staff will provide the confidential report accompanied by a formal presentation that summarizes the report to DCOR management.

Action Item Matrix

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Appendices

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Appendix A Acronyms

ANSI	American National Standards Institute
API	American Petroleum Institute
ASME	American Society of Mechanical Engineers
BAT	Best Achievable Technology
BEP	Business Emergency Plan
BOPD	Barrels of Oil Per Day
BWPD	Barrels of Produce Water Per Day
CEC	California Electrical Code
CFC	California Fire Code
CP	Control Panel
CSLC	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
ESD	Emergency Shutdown
FSL	Flow Safety Low
FSV	Flow Safety Valve
FWKO	Free Water Knock Out
HF	Human Factor
HT	Heater Treater
HMI	Human Machine Interface
H ₂ S	Hydrogen Sulfide
kVA	KiloVolt Amperes
kW	Kilowatts
LACT	Lease Automatic Custody Transfer
LED	Light Emitting Diode
LEL	Lower Explosive Limit
LLC	Limited Liability Company
MCC	Motor Control Center
MOC	Management of Change
MRMD	Mineral Resources Management Division
MSDS	Material Safety Data Sheet
NEC	National Electrical Code
NEMA	National Electrical Manufacturers Association
NETA	International Electrical Testing Association
NFPA	National Fire Protection Association
OSCP	Oil Spill Contingency Plan
OSHA	California Occupational Safety & Health Administration
OSPR	Office of Spill Prevention and Response
P&ID	Piping and Instrumentation Diagrams
PFD	Process Flow Diagram
PHA	Process Hazard Analysis
PLC	Programmable Logic Controller
PM	Preventative Maintenance
PPE	Personal Protective Equipment

PRC	Public Resources Code
PSH	Pressure Safety High
PSHL	Pressure Safety High-Low
PSI	Pounds per Square Inch
PSL	Pressure Safety Low
PSM	Process Safety Management
PSV	Pressure Safety Valve
RP	Recommended Practice
RTU	Remote Terminal Unit
SAC	Safety Analysis Checklist
SAFE	Safety Analysis Function Evaluation
SAMS	Safety Assessment of Management Systems
SCADA	Supervisory Control and Data Acquisition
SCBA	Self Contained Breathing Apparatus
SCE	Southern California Edison
SMP	Safety Management Programs
SOP	Standard Operating Procedures
SPCC	Spill Prevention Control & Countermeasure
TEC	Technical
UV/IR	Ultraviolet/Infrared
UBC	Uniform Building Code
UFC	Uniform Fire Code
UPS	Uninterruptable Power Supply
UT	Ultrasonic Thickness
V	Volt

Appendix B Best Practices

1.0 BEST PRACTICES

- | | | |
|-----|---|-------------------------|
| 1.1 | Best Achievable Protection/Best Achievable Technology | PRC 8750 |
| | Inspection of Marine Facilities | PRC 8757 |
| | CSLC Oil & Gas Regulations | CSLC 2 CCR Art. 3 - 3.6 |

2.0 FACILITY CONDITION AUDIT

- | | | |
|-----|---|--|
| 2.1 | Methodology for Audit | |
| 2.2 | General Facility Conditions | |
| | 2.2.1 <i>Housekeeping</i> | CSLC 2123 & 6539 |
| | 2.2.2 <i>Stairs, Walkways, Gratings, & Ladders</i> | CAL OSHA Title 8 CCR |
| | 2.2.3 <i>Escape/Emergency Egress/Exits</i> | CAL OSHA 22, 25, 3215 & 6577 |
| | 2.2.4 <i>Labels, Placards, & Signs</i> | CAL OSHA & API RP 14J |
| | 2.2.5 <i>Security</i> | CSLC 2123 |
| | 2.2.6 <i>HAZMAT Storage</i> | OSHA 29 CFR 1910.1200 |
| 2.3 | Field Verification of Plans | |
| | 2.3.1 <i>PFID</i> | CSLC 2132(a)(2) & API 51R |
| | 2.3.2 <i>P&ID</i> | CSLC 2132(a)(2) & API 51R |
| | 2.3.3 <i>Fire Protection Drawing</i> | CSLC 2132(g)(4)(G) & API 51R |
| 2.4 | Condition and Integrity of Major Systems | |
| | 2.4.1 <i>Piping</i> | CSLC 2129(b) & (c), Cal OSHA 6533, API 570 & CFR 1910.106(c)(4) |
| | 2.4.2 <i>Tanks</i> | CSLC 2129(b) & (c), API RP 653 & 572 |
| | 2.4.3 <i>Pressure Vessels</i> | CSLC 2129(b) & (c), ASME Boiler PV Code Sect. VIII, API RP 510 & 572, CCR Title 8 Sec. 6551(c) & 46 CFR 53 |
| | 2.4.4 <i>Pressure Relief, PSVs and Flare Sys.</i> | CSLC 2132(g)(3), API RP 14J, 520, 521 & 576 |
| | 2.4.5 <i>ESP, Pump Units & Wellhead Equip.</i> | CSLC 2132(a)(4) |
| | 2.4.6 <i>Fire Detection</i> | CSLC 2132(g)(1)(C) & NFPA |
| | 2.4.7 <i>Fire Fighting Equipment and Systems</i> | CSLC 2132(g)(4)(A) & NFPA 25 - 10.2.5.1 |
| | 2.4.8 <i>Combustible Gas & H₂S Detection</i> | CSLC 2132(g)(5) & (6) |
| | 2.4.9 <i>Emergency Shutdown Device</i> | CSLC 2132(g)(1) & API RP 14J |
| | 2.4.10 <i>Safety & Personnel Protective Equip</i> | CAL OSHA |
| | 2.4.11 <i>Lighting</i> | CAL OSHA |
| | 2.4.12 <i>Instrumentation, Alarm, & Paging</i> | CSLC 2132(g)(1)&(2), API RP 14J & 8 CCR 5189 |
| | 2.4.13 <i>Auxiliary Generator/Prime Mover</i> | CSLC 2132(g)(7) |
| | 2.4.14 <i>Spill Containment</i> | CSLC 2139 & 2140, 40 CFR 112.7(c) & GOV CODE 8670 |
| | 2.4.15 <i>Spill Response</i> | CSLC 2139 & 2140 & GOV CODE 8670 |
| 2.5 | Mechanical Integrity | CSLC 2129(c) & CAL OSHA 8 CCR 5189 (j) |

- 2.6 Offshore Production Safety Systems CSLC 2132 (g)(1)&(2), API RP 14C,
OSHA 5(a)(1), 40CFR 68.65
- Onshore Production Safety System CSLC 2132 (g)(1) & (2), API RP 14C
OSHA 5(a)(1) & 40CFR 68.65

3.0 ELECTRICAL SYSTEMS AUDIT

- 3.1 Goals and Methodology
- 3.2 Hazardous Area Electrical Classification Dwgs. RP 500, NFPA 70, 496 & CEC 500 &
501
- 3.3 Electrical Power Dist. System, Normal Power
 - 3.3.1 *Electrical Single Line* API RP 540, NFPA 70 & CEC 110 &
500.5
 - 3.3.2 *Electrical Service Capacity* API RP 540, NFPA 70 & CEC 408.4
- 3.4 Elec. Power Equip Condition and Functionality
 - 3.4.1 *Equipment Condition* API RP 540, NFPA 70 & CEC 110,
314, 344, 408 & 501
 - 3.4.2 *Equipment Maintenance Practices* API RP 540, NFPA 70 & CEC 110,
314, 490 & 501
- 3.5 Grounding API RP 540, NFPA 70 & CEC 250,
408.40 & 501.30
- 3.6 Emergency Electrical Power
 - 3.6.1 *System Configuration* API RP 540, NFPA 70 & 110 & CEC
110 & 700
 - 3.6.2 *Equipment & Component Ratings* API RP 540, NFPA 70 & 110 & CEC
110 & 700
 - 3.6.3 *Electrical System Design Safety* API RP 540, NFPA 70 & 110 & CEC
110 & 700
- 3.7 Electric Fire Pump API RP 14F, NFPA 20, NEC 696 &
CEC 110 & 700
- 3.8 Process Instrumentation API RP 14F & 540 & NFPA 70
- 3.9 Standby Lighting API RP 14F
- 3.10 Special Systems
 - 3.10.1 *Safety Control Systems* API RP 14C & CEC 110
 - 3.10.2 *Gas Detection System* API RP 14C
 - 3.10.3 *Fire Detection Systems* API RP 14F & 14G & API 2001
 - 3.10.4 *Aids to Navigation* Coast Guard & CEC 110
 - 3.10.5 *Communication* API RP 14F & CEC 110
 - 3.10.6 *General Alarm* API RP 14F & CEC 760
 - 3.10.7 *Cathodic Protection* API RP 651, NACE RP 01-76 & 0675
& CEC 110 & 250

4.0 SAFETY MANAGEMENT PROGRAMS AUDIT

- 4.1 Goals and Methodology API RP 75 SEMP,
OSHA 29 CFR 1910.119 &
CAL OSHA 8 CCR 5189
- 4.2 Operations Manual CSLC 2175(b)(4) & (13), CFR
119.119(f) & API RP 51R
- 4.3 Facility Oil Spill Response Plan CSLC 2132 (b) & (c) & 40 CFR 112
4.3.1 EPA – SPCC 40 CFR 112

4.4 Training and Drills

CSLC 2175 (b)(6)(C & D) & (7)(A, B,
C & D) & OSPR GOV CODE 8670
API RP 75 SEMP, OSHA 29 CFR
1910.119 & Cal OSHA 8 CCR 5189

4.5 Safety Management Programs

5.0 HUMAN FACTORS AUDIT

5.1 Goals of the Human Factor Audit

5.2 Human Factors Audit Methodology

CAL OSHA 8 CCR 5189, API RP 75 &
CSLC Safety Audit of Mgmt Systems
(SAMS)

Appendix C References

GOVERNMENT CODES, RULES, AND REGULATIONS

CSLC	California State Lands Commission
2123	<i>Lease Operations on Uplands</i>
2129	<i>Article 3.3 -Oil and Gas Production Regulations</i>
2132	<i>Production Regulations</i>
2139	<i>Oil Spill Contingency Plan</i>
2140	<i>Pollution Control and Removal Equipment</i>
2173	<i>General Requirements – Operations Manual</i>
2174	<i>Manual Review</i>
2175	<i>Manual Content</i>
Cal OSHA	California Occupational Health and Safety
3215	<i>Means of Egress</i>
3222	<i>Arrangement and Distance to Exits</i>
3225	<i>Maintenance and Access to Exits</i>
3308	<i>Hot Pipes and Hot Surfaces</i>
3340	<i>Accident Prevention Signs</i>
5189	<i>Process Safety Management of Acutely Hazardous Materials</i>
6533	<i>Pipe Lines, Fittings, and Valves</i>
6551	<i>Vessels, Boilers and Pressure Relief Devices</i>
6556	<i>Identification of Wells and Equipment</i>
CCR	California Code of Regulations
1722.1.1	<i>Well and Operator Identification</i>
1774	<i>Oil Field Facilities and Equipment Maintenance</i>
1900-2954	<i>California State Lands Commission, Mineral Resources Management Division Regulations</i>
CFR	Code of Federal Regulations
29 CFR	<i>Part 1910.119 Process Safety management of Highly Hazardous Chemicals</i>
30 CFR	<i>Part 250 Oil and Gas Sulphur Regulations in the Outer Continental Shelf</i>
33 CFR	<i>Chapter I, Subchapter N Artificial Islands and Fixed Structures on the Outer Continental Shelf</i>
40 CFR	<i>Part 112, Chapter I, Subchapter D Oil Pollution Prevention</i>
49 CFR	<i>Part 192, Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standard</i>
49 CFR	<i>Part 195, Transportation of Liquids by Pipeline</i>

INDUSTRY CODES, STANDARDS, AND RECOMMENDED PRACTICES

ANSI	American National Standards Institute
B31.3	<i>Petroleum Refinery Piping</i>
B31.4	<i>Liquid petroleum Transportation Piping Systems</i>

B31.8 Gas Transmission and Distribution Piping Systems
Y32.11 Graphical Symbols for Process Flow Diagrams

API American Petroleum Institute

RP 14B Design, Installation and Operation of Sub-Surface Safety Valve Systems
RP 14C Analysis, Design, Installation, and Testing of Basic Surface Safety Systems for Offshore Production Platforms
RP 14E Design and Installation of Offshore Production Platform Piping Systems
RP 14F Design and Installation of Electrical Systems for Offshore Production Platforms
RP 14G Fire Prevention and Control on Open Type Offshore Production Platforms
RP 14H Use of Surface Safety Valves and Underwater Safety Valves Offshore
RP 14J Design and Hazards Analysis for Offshore Production Facilities
RP 51 Onshore Oil and Gas Production Practices for Protection of the Environment
RP 55 Oil and Gas Producing and Gas Processing Plant Operations Involving Hydrogen Sulfide
RP 500 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 Instrument Society of America

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

NACE	National Association of Corrosion Engineers
<i>RPO169</i>	<i>Control of External Corrosion on Underground or Submerged Metallic Piping Systems</i>
NFPA	National Fire Protection Agency
<i>20</i>	<i>Stationary Pumps for Fire Detection</i>
<i>25</i>	<i>Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems</i>
<i>70</i>	<i>National Electric Code</i>
<i>704</i>	<i>Identification of the Hazards of Materials for Emergency Response</i>
CEC	California Electric Code

Appendix D Team Members

FACILITY CONDITION TEAM

CSLC – MRMD	Mark Steinhilber Steve Staker David Calderon
DCOR Ft. Apache	Matt Civitelli Nick Nicotera

ELECTRICAL TEAM

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PES	Doug Effenberger
DCOR Ft. Apache	Dennis Conley

TECHNICAL TEAM

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SAFETY MANAGEMENT TEAM

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DCOR Ft. Apache	Scott Knight