1.0 Introduction

This appendix discusses hazardous materials, safety and risk assessment methodology and impacts that are associated with the baseline conditions and the Project, including those that could adversely affect public health. The potential discharge of hazardous materials into the environment, such as crude oil spills, is also quantified in this section

1.1 CHARACTERISTICS OF CRUDE OIL

As it emerges from the wellhead, crude oil is a heterogeneous mixture of solids, liquids, and gases. This mixture includes sediments, water and water vapor, salts, and acid gases, including H_2S and carbon dioxide. A spill of crude oil from a well blowout or leaks from pipelines or tanks could result in toxic vapors and fires that may arise if the oil or the oil vapors reach an ignition source and the oil burns. Flammable vapors that may emanate from crude oil include propane, butane, and pentane. There may also be safety hazards resulting from toxic vapors, primarily benzene and hydrogen sulfide (H_2S).

Sulfur occurs in many natural compounds such as H_2S in crude oil. Total sulfur content in crude oils ranges from approximately one to four percent by weight, and H_2S concentrations can reach 150 parts per million (ppm) in “sour” crude oil. Other constituents of crude oil include nitrogen and oxygen compounds, and water- and metal-containing compounds, such as iron, vanadium, and nickel.

Most of the light ends of the oil stream (e.g., the propane, butanes, etc.), and the H_2S are currently removed from the crude oil through processing at the EOF. Some H_2S does remain in the crude oil, however. The historical levels of H_2S in the crude oil from Platform Holly have ranged from 12 to 115 ppm and measured 75 ppm in 2015, according to Applicant application submittals. In the vapor space of the EOF crude oil tanks, H_2S concentrations have been measured as high as 9,000 ppm (SBCFD 2000). This is equilibrium concentration and the gas concentration above a pool of spilled crude oil would be expected to be much lower. H_2S can produce highly toxic effects, or, in lower concentrations, nuisance odors. See Section 4.3, *Air Quality*, for a discussion of odor impacts.

1.2 RISK ASSESSMENT

The risk assessment involves analysis of impacts to two potential areas: immediate public health impacts and impacts to the environment due to spills.

Immediate public health risks are defined as impacts to the public causing immediate serious injuries or fatalities, such as burns from exposure to flames or burning vapors, inhalation of toxic materials at levels causing immediate health threats, or broken bones or ear drums due to overpressures. Risk is defined as a combination of the

exposure/consequence of a release and its associated frequency. Health impacts related to exposure to chemicals over a more extended period of time, are addressed in Section 4.3, *Air Quality*, in a health risk assessment addressing cancer, chronic and acute impacts. Assessing the risk of immediate public health impacts involves combining the hazardous release scenarios with the respective populations that could be exposed to each scenario, and the respective frequencies of each scenario. The risk analysis examines only the risks to the public. It does not examine risks to employees of the Applicant and its contractors.

The first phase of the public health risk assessment methodology is determining the hazardous scenarios that could occur at the Project facilities as they are currently configured. These scenarios are then characterized by the possible consequences or impacts they could induce, including hazard zones (i.e., that distances that hazards could reach) and the number of individuals affected. Often, each scenario consists of several events that have to occur before a hazardous consequence could occur. For example, a crude oil tank failure has to be followed by a sizable crude oil leak, followed by ignition and subsequent fire, and then members of the public would need to be present within the fire hazard zone to be affected.

Meteorological conditions affect characteristics of releases that generate cloud effects, such as toxic and vapor cloud events. For toxic and vapor cloud events, a cloud is produced downwind. The frequency of a given receptor experiencing the effects of release (i.e., within the hazard zone) is dependent on the wind blowing in the direction of that receptor. To a lesser extent, overpressure and fire thermal effects are independent of wind direction and will affect the entire area within a given radius of the release point.

Scenario frequencies are estimated by examining the individual components of a scenario that would combine to produce a release and assigning frequencies to each component based on industry-wide databases and specific site operating characteristics. Both leaks and ruptures are examined for each scenario in order to assess a range of release quantities, and frequencies, and, therefore, risk, for each scenario.

The risks of spills to the environment are assessed by examining the potential spill volumes and the projected spill frequencies. The level of risk is determined by the amount that a proposed Project changes the spill volumes and the frequency of that spill scenario.

For spills into the environment, spill volumes are estimated based on vessel and tank sizes and pipeline volumes and throughputs. Spill frequencies are divided into the frequency of leaks or small spills, and the frequency of ruptures or large spills, with small spills being those of less than 50 bbls and larger spills of 50 bbls or more.

Previous documents covering the Project facilities, such as the hazards analysis conducted by the Santa Barbara County Fire Department (SBCFD 2000), were used to formulate the scenarios, the hazardous scenario frequencies, and the hazard zones for existing operations, with modifications based on the current operating parameters. Additionally, failure frequency databases were used (CCPS 1989; CCPS 1996; CSFM 1993; HLID 1992; Lees 1996; MMS 2000; Rijnmond 1982). While failure frequency databases, such as those published by the CCPS, have not been updated in a number of years, their results are considered valid as being towards the higher range of failure frequencies, are, therefore, more conservative, and are still useful particularly when used to assess incremental increases in risk, as in this EIR.

Existing population information was utilized to estimate the population that could be affected by an accidental spill or release.

1.2.1 Failure Frequencies, Equipment Age and Equipment Maintenance

Industry data on the correlation between equipment age and failure rates is sparse, and a number of studies indicate that there is no correlation. In the Phillips and Warwick study (Lees 1996), 50 percent of failures were attributable to pressure vessels that were less than ten years old, and 50 percent were attributed to vessels that were older than ten years. This is due primarily to the fact that many failures occur during the first few years due to manufacturing inadequacies.

However, other studies indicate an increase in failure rates with age. Thomas (1981) developed a quantitative method for determining the failure rates in process piping and vessels using empirical data from the process industry. His method involved examining the piping and vessel size, construction geometry, number and length of welds, as well as the equipment age and maintenance practices. His method assigned an age factor as large as 1.4, meaning failure rates would increase by approximately 40 percent at the age of 20 years, over the failure rate at 10 years. Thomas estimated that causes of process piping leaks are due primarily to manufacture and materials selection (50 percent), and corrosion and erosion (25 percent), with fatigue, vibration, expansion, mal-operation and shock making up the remaining areas (Medhekar 1993).

Since the Thomas report, a number of refinements and data development activities have occurred mostly focused on the nuclear industry. The development of “risk informed in service inspection (RI-ISI)” techniques have been developed by the world-wide nuclear industry. A number of approaches to RI-ISI have been proposed, but most rely on assessing the severity of process degradation mechanics and assigning a level of risk to specific processes. Databases have been developed, namely the SKI-PIPE for the world-wide nuclear industry, which allow for a comparison to the Thomas model and databases. A study examining the SKI-PIPE database (Lydell 2000) indicates that the

age factor can range as high as 2.0 for larger diameter pipes in facilities older than 25 years, and as high as 2.5 for pipes subject to stress-corrosion cracking environments.

The California State Fire Marshall (CSFM) 1993 study on pipelines indicates that pipeline leak rates stay relatively constant up to the 30 to 40 year timeframe and then increase substantially (CSFM, 1993). The oldest pipelines have failure rates 2.8 times greater than the average.

For this study, it was assumed that as equipment ages beyond the first 10 to 20 years, to the age of 40+ years, lack of proper maintenance would substantially increase failure rates. However, if proper maintenance practices are employed, and equipment is repaired or replaced on a proactive basis, it was assumed that failure rates would still increase over the lower rates seen in the industry. As all age related degradation issues, such as corrosion, fatigue, and shock, cannot be captured by even the best maintenance programs, failure rates have been increased by a factor of 2.0 for equipment with an age greater than 20 years.

This was quantified by examining the range of failure rates between the different databases (WASH 1975, Lees 1996, HLID 1992, Rijnmond 1982, CCPS 1989) and assigning the higher failure rates to equipment that receives less maintenance. The failure rates for a rupture of process piping, for example, from a number of reputable studies (WASH 1975, Lees 1996, CCPS 1989, and Rijnmond 1982) range from a very high rate of once every 40,000 meter-years, to a very low rate of once every 11 million meter-years This results in an average failure rate of about once every 1.9 million meter-years. The higher values are assumed to correlate to facilities that operate under corrosive service, and that receive below-standard maintenance practices. The lowest rates are assumed to correlate to facilities that have less/non-corrosive service and receive the highest standards of maintenance.

Appropriate maintenance was determined from the State of California Safety Orders, the California Fire Code, NFPA and API, as well as industry practice as established by maintenance plans submitted to Santa Barbara County. Appropriate maintenance would include the following practices:

- An established computerized maintenance management system, including record keeping, design review, maintenance checklists, diagnostic's recording, preventative scheduling and monitoring.
- For piping and pipelines, both visual and ultrasonic/non-destructive testing (NDT) inspections for corrosion, as per API 574, and cathodic potential inspections (for underground piping), as is conducted on many pipelines utilizing smart pigs and cathodic potential systems. Pipe coating would be maintained to protect against weathering, and pipe bracing should be maintained for seismic considerations. The frequency of NDT testing of process piping would be as per API 570 and would be a

function of the corrosiveness of the service. However, a baseline should be established for older piping.

- For vessels, periodic (every five years) external and internal visual and ultrasonic testing. Maintenance of vessel bracing and bolting for seismic considerations.
- For atmospheric tanks, the external inspection is required every five years, ultrasonic wall testing every five years, bottom examination every ten years and appropriate seismic design considerations to prevent failure in an earthquake.
- For valves, checking for small leaks on a frequent (greater than annual) basis, as small leaks are frequently precursors to larger leaks and ruptures. Valves should also be tested on at least an annual basis to ensure operational effectiveness, and should be refurbished periodically, including seal and seat refurbishment or replacement, as per manufacturer's recommendations.
- For rotating equipment, such as pumps and compressors, appropriate maintenance may involve replacing seals, oil maintenance, and a number of other operations, as per the manufacturers' recommendations. Also, design issues are important, such as having redundant systems to allow for more frequent maintenance activities, and seismic bracing for piping and equipment.
- For sensor equipment, such as lower explosive limit (LEL) fire eyes and H_2S sensors, appropriate maintenance would involve replacing sensors when new technology presents a significant improvement in reliability, and conducting monthly inspections and testing to ensure operational effectiveness.
- For pressure relief design and maintenance, pressure relief should be to safe locations, preferably enclosed flare systems. Pressure relief valves should be pressure checked on an annual basis. Those pressure relief valves that are repaired based on a failed annual test should be retested within six months.
- For control systems, such as level, pressure, vibration and temperature, annual testing including actuation of system to ensure operation.
- The emergency shut-down system should be checked and tested annually.
- For fire water systems, testing annually, pressure testing of water header, verification of flow alarms, fire pumps weekly inspection and annual performance test, foam system sampled and analyzed annually.

1.2.2 Existing Facility Risks - Platform Holly and Offshore Pipelines

Existing facility risks are related to the immediate public health risks associated with releases of hazardous materials that could impact the public through explosions, fires or toxic releases, and the spills of hazardous materials that could impact the environment. For the immediate public health risks, release scenarios, the corresponding frequency and impacts of these scenarios and the resulting risk levels are discussed below. Spill

risks are then discussed in terms of the frequency of spills and the corresponding consequences or spill volumes.

Immediate Health Risks of Hazardous Materials - Platform Holly and Offshore Pipelines

A range of scenarios was developed to consider the existing, immediate risks of Platform Holly and offshore pipeline facilities to public health. Each of these scenarios is discussed below.

Platform Holly could have two types of releases, a release of sour gas that could impact the public health of nearby boaters, or a release of crude oil that could cause impacts to the environment. A crude oil release could ignite and cause impacts to the public health and safety of nearby boaters. A low probability larger spill associated with a well blowout could have wider reaching affects, especially if oil reached the shoreline.

The 2000 QRA (SBCFD 2000) indicated that sour gas releases from Platform Holly would not present significant risk to the public, based on the low density of public boats in the platform vicinity. Therefore, public health impacts for sour gas from Platform Holly were not analyzed further in this analysis. For more details on the public health impacts for Platform Holly, refer to the 2000 QRA (SBCFD 2000, Appendix R). The analysis of the portion of the gas pipeline on the beach is discussed under the EOF risk assessment below.

Crude oil extracted by Platform Holly is relatively heavy, and spills of crude oil would be odiferous, but generally would not present a serious health impact to area beach goers for spills that reach the beach. There is a possibility that the spilled crude oil could ignite and burn. However, the crude oil vapors would not collect to the extent that they could produce a flammable cloud and subsequent explosion, unlike spilled gasoline, for example. A Quantitative Risk Assessment was conducted for the City of Goleta (COG 2011, Appendix R) that demonstrated the low level of risk associated with the pipelines.

Department of Transportation (DOT) nationwide data on 3,147 crude oil pipeline spills indicates that, between 1986 and 2012, four deaths have occurred related to crude oil pipeline spills. Two of these resulted from employee accidents related to maintenance activities, and the other two occurred when a driver and a passenger of a vehicle ran into an above-ground crude oil pipeline. A total of 41 injuries have occurred associated with crude oil pipelines since 1986 nationwide, with all of them being injuries to employees except a single incident in 1987 in Texas where work on a crude oil pipeline within a mobile home park sparked a fire causing eight injuries. This demonstrates the low probability that a crude oil spill from a pipeline could produce fatalities or injuries. Further, as the Platform Holly to EOF pipeline are subsea over most of their length, substantial populations are not vulnerable to offshore crude oil pipeline spills. Rather, the risks would be most substantial for Platform Holly employees and boaters in the vicinity of the platform.

1.2.3 Spill Risks - Platform Holly and Offshore Pipelines

Spills risks are assessed by examining the scenarios that could result in a spill, assigning frequencies to the scenarios and determining potential spill volumes. Each of these is discussed below.

1.2.3.1 Existing Spill Risk Scenarios - Platform Holly and Offshore Pipelines

Crude oil spills from Platform Holly could occur as a result of the following scenarios:

1. Well Blowouts

Blowouts occur when a drilling activity encounters an area of sufficient pressure that the drilling muds cannot contain the reservoir fluids, or when muds circulation is lost with muds flowing into the formation out of the well-bore, and the reservoir pressure causes oil and gas to flow back up the well to the surface (loss of well control). Blowouts can occur during drilling or well work-over operations. Blowouts can also occur during normal production on wells that are naturally flowing (i.e., are pressurized) or operate on gas lift. From 1980 through 2012, a total of 196 blowouts/well releases from the US Gulf of Mexico oil and gas wells occurred (SINTEF 2016). In 1969, a Federal platform offshore Santa Barbara experienced a blowout in one of its wells with an estimated 80,000 barrels of oil released into the ocean. An example of a gas well blowout is the Aliso Canyon blowout that occurred in October, 2015 near Porter Ranch in Los Angeles County, and lasted for close to 4 months, although this blowout was onshore and was from a gas storage facility, not an offshore oil reservoir. A blowout resulting in a release would involve failure of equipment and subsequent failure of the safety system and would produce a release of process fluids (gas, crude oil and water).

2. Loss of containment at wellhead

The wellheads are located on top of the wells and are equipped with shut-down valves, both on the well (surface safety valve [SSV]) and subsurface within the well-bore (subsurface safety valve [SSSV]). This scenario would involve failure of equipment and subsequent failure of the safety system producing a release of process fluids (gas, crude oil and water) from the well area.

3. Loss of containment through the group separators and the surge vessels

This scenario involves a release downstream of the SSV to the pipeline pig launchers. It includes the crude oil emulsion streams at the group separators and the surge vessels. The release could be due to pipe, vessel or valve failures. This scenario could result in a large spill, even if the wellhead safety systems operate as intended, because the vessels have an inventory of crude oil in them.

4. Pumping and Shipping Spills at Platform Holly

Once the crude oil is separated from the gas and some of the water, the crude emulsion is pumped through valves and a pig launcher to the EOF. Failure of the pumps, valves, piping, or failures during launching of the pigs could cause a release of crude oil/emulsion.

5. Diesel fuel loading and miscellaneous spills

Diesel fuel is used on Platform Holly to power the crane and miscellaneous equipment. Failures during diesel fuel unloading could cause a spill of diesel fuel to the ocean. The diesel tank on Platform Holly has a capacity of 1,500 gallons. Miscellaneous spills would include spills due to lubricant leaks, mud handling, and other materials used on the platform. The historical rate of miscellaneous spills has been added to the frequency analysis. In addition, a large spill could occur if a ship or vessel collides with the platform resulting in a total platform loss from all of the platform inventory. Wells would shut off due to the fail safe mode of the SSSVs, although all SSSVs would have to function correctly.

6. Offshore Pipeline Failures

The offshore emulsion pipeline could leak or rupture causing crude oil and produced water to spill to the marine environment. Failures of the pipeline could be caused by metallurgical failure of pipe walls due to corrosion or stress from unsupported spans, due to failures of the piping due to construction anomalies (such as incorrect weld techniques or stress on pipe), from valve or connection failures, or from third-party boat anchors or other equipment impacting the pipe. As the pipe is also occasionally exposed on the beach during and after major winter storms, strong wave or debris (e.g., cobble or rock movement by large surf) impact associated with storms could damage the pipeline, causing a release. Failures of the sour gas pipeline on the beach and between the beach and the EOF are addressed under the EOF risk assessment below.

7. Platform Drain System Failure

Platform Holly operates as a closed system with regard to on-platform spills and storm-water collection. Fluids (including spills or storm water) that enter the deck areas are routed to the drain system which captures the fluids and then pumps the fluids into the emulsion process stream before the separators. This system is limited both by the deck capacity to hold liquids, and the system pumps that pump the liquids into the emulsion process stream. Each deck is enclosed by a welded “lip” to capture the liquids. The ability of the deck drain system to move liquids away from the decks is determined by the drain capacity and the system pumps. The deck drains drain to drain tanks that have a combined capacity of 200 bbls, and the drain pump, which directs the fluids back into the emulsion system and is a single, non-redundant pumping system, has a

pumping capacity of 150 gpm, or approximately 5,000 bpd. The drain system pumping capacity is below the peak well total fluids production level in 2014 of 7,964 bpd (for well 3242-18 as per DOGGR), which, according to the 2015 SPPP, is the only well on Platform Holly not equipped with a SSSV. If a rupture release from the highest total fluids producing well were to occur, it could overwhelm the drain system in 100 minutes, or if the entire well header flow released, the drain system could be overwhelmed in 20 minutes. While these scenarios could occur, they would only occur if the shutdown valve/system on the well also failed. In general, the drain system substantially reduces the frequency of spills entering the marine environment.

Spill histories offshore have indicated that spills to the ocean can occur even with a drain system if a spill occurs when it is windy or if a release has sufficient velocity to "ride over" the deck lip. Winds in excess of 20 knots (10 meters/second) were assumed to produce this type of situation. Also, if a failure of any part of the drain system were to occur, such as drain plugging, pump, piping, tank, or valve failures, a subsequent spill could be released to the ocean.

The failure of the Platform Holly drain system discussed above would not, in and of itself, result in a release of process fluids, but would allow a release from process equipment to reach the ocean. It is, therefore, considered to be a contributing event to a release to the marine environment and is included in the frequency analysis.

This analysis assumes that rupture releases associated with catastrophic vessel failures, pipe ruptures or catastrophic well blowouts, would reach the ocean regardless of whether the Platform Holly drain system operates as intended.

1.2.3.2 Existing Spill Risks Scenarios Frequencies - Platform Holly and Offshore Emulsion Pipeline

Spill scenario frequencies have been developed for Platform Holly and the offshore pipelines based on industry-wide databases combined with site-specific analysis of the operations and equipment arrangements.

Platform Holly spill frequencies are based on the equipment arrangements (number of vessels, valves, length of piping, etc.), the probability of a Platform Holly drain system failure, and historical information on the number of spills associated with miscellaneous operations, such as supply boat transfers, mud handling, etc. Spill frequencies were calculated both on an annual basis and as a "years between spills" basis. Table 1 shows the estimated spill frequencies and estimated "years between spills" for Platform Holly and the emulsion pipeline.

Table 1 Platform Holly and Offshore Pipeline Spill Frequencies: Existing Operations

Scenario	Frequency, per year	Years between Spills (Return Period)
Small Spills and Leaks (< 50 bbls)		
Platform Holly - Blowouts - any size spill	7.52×10^{-3}	132.9
Platform Holly - Wellhead Area Spill to Ocean - leak	2.21×10^{-3}	452.1
Platform Holly - Separator Failure Spill to Ocean - leak	1.98×10^{-3}	504.7
Platform Holly - Pumping and Shipping Spill to Ocean - leak	7.70×10^{-2}	13.0
Platform Holly - Diesel Fuel Loading - Spill to Ocean	1.06×10^{-1}	9.4
Platform Holly - Misc. Material Spills	3.50×10^{-1}	2.9
Offshore Crude Pipeline - leaks	9.07×10^{-2}	11.0
Cumulative Small Spills	6.35×10^{-1}	1.6
Large Spills/Ruptures (> 50 bbls)		
Platform Holly - Blowouts Catastrophic	3.05×10^{-3}	328
Platform Holly - Wellhead area - rupture	6.28×10^{-5}	15,935
Platform Holly - Separator Failure Spill to Ocean - rupture	6.57×10^{-4}	1,522
Platform Holly - Pumping and Shipping Spill to Ocean - rupture	5.19×10^{-4}	1,927
Platform Holly - External impact	1.00×10^{-5}	100,000
Offshore Crude Pipeline - ruptures	2.39×10^{-2}	42
Cumulative Large Spills	2.82×10^{-2}	35

Notes: Years is defined as the expected years between spills. Frequency per year denoted in scientific notation: i.e. 7.52×10^{-3} is equal to 0.00752.

While pipelines historically have had one of the lowest spill rates of any mode of oil transportation, there is still some level of risk that a pipeline could leak or rupture. This potential was demonstrated by the May 2015 Refugio Oil Spill, which occurred after the PAAPLP Coastal Pipeline ruptured near Rufugio State Beach along the Gaviota Coast. In order to estimate the frequency of such an event, historic data for other operating liquid pipelines have been used.

As a pipeline system is a fixed structure, the spill frequency from a pipeline is essentially fixed, regardless of the amount of crude oil transported. A number of different sources are used in this report to estimate the frequency of crude oil pipeline spills. Please see Appendix R for a discussion of the sources used to determine the frequency of spills. These include the DOT databases (U.S. DOT 2013) and the CSFM databases and reports (CSFM 1993). Each is discussed below, and their estimates of pipeline spill frequencies are used to define a range of possible failure frequencies.

Information on the number and causes of pipeline spills in the United States greater than 5 gallons or 50 bbls in size is available from the DOT OPS (depending on the reporting year). These data were obtained for spills occurring from 2003 to 2012. A total of 268 spills were reported during that timeframe covering 7,374 miles of hazardous liquid pipelines within California. Spills caused by materials failure such as welds, etc. (for hazardous liquid pipelines), ranked highest, at 25 percent of spills, with spills caused by corrosion ranking second, with an estimated 24 percent of all spills. The overall spill rate of hazardous liquid pipeline spills within California was estimated to be 3.6 spills per 1,000 mile-years .

The DOT rate for hazardous liquid pipeline spills includes crude oil pipelines, refined product pipelines and other hazardous liquid pipelines. Approximately 56 percent of pipeline mileage is crude oil, with the remaining mileage being refined product or highly volatile liquids. A breakdown of the DOT database for California demonstrates that, for the years 2010 to 2014, 2002 to 2010 and pre-2002, the DOT rate for only crude oil pipelines in California ranged up to 4.54 spills per 1,000 mile years. This higher rate was the more recent data reflecting the lower reporting threshold (from 50 bbls before 2002 to 5 gallons after 2002).

A CSFM report, *Hazardous Liquid Pipeline Risk Assessment* (CSFM 1993), analyzes leak information for the 7,800 miles of liquid pipelines within California for the years 1981 through 1990. This study adjusted pipeline spill rates based on variables such as pipeline age, diameter, and operating temperature, as well as spill cause. The study found that external corrosion was the major cause of pipeline leaks, causing approximately 59 percent of spills, followed by third-party damage at 20 percent. Older pipelines and those that operate at higher temperatures had significantly higher spill rates. The CSFM base rate for crude oil pipeline spills of any size and under any operating conditions was calculated to be 9.89 incidents per 1,000 mile-years . Crude oil had the highest spill rate primarily due to the transportation of crude oil at elevated temperatures, which increases the rate of external corrosion. Faster corrosion rates occur at elevated temperatures when metal comes in contact with soil moisture.

Spill frequencies were estimated in this report using information on crude oil pipeline spill rates available from the CSFM report. Although the CSFM data is older, it has the advantage of being able to specifically characterize the failure rate for the characteristics of the pipeline in question (i.e., by operating temperature, diameter, SCADA system, material, etc.). Although the CSFM study does not break out the analysis by offshore pipelines or pipelines that operate in batch mode (some pipelines in the CSFM report most likely do operate in batch mode, but the failure rate for these pipelines was not detailed), the CSFM data are considered to be the most conservative of the databases available, i.e., most protective of the environment. The DOT studies indicated a lower, although comparable, rate than the CSFM rates used in this study.

Pipelines that operate offshore are exposed to a more extreme environment, i.e., more corrosive, different set of third party impacts (boats, anchors, etc.), than onshore pipelines and might be expected to have a higher failure rate. In fact, the Seep Tent pipeline currently has a third-party anchor chain impact that was discovered on an ROV survey of the pipelines. However, older spill rates estimated from BOEM information (MMS 2000, Anderson 1999) indicate that offshore rates are similar to, if not less than, the CSFM rates described above. In this study, therefore, the CSFM rates have been used in order to ensure a conservative estimate.

Offshore conditions are often taxing on pipelines and other oil infrastructure, such as increased corrosion or debris buildup. For example, an abandoned anchor chain historically has laid on the Seep Tent pipeline. Additionally, the Platform Holly pipelines are exposed to weather and wave action where they emerge on the beach.

Source: HDI 2007, beach picture taken June 13, 2007

In addition, the Platform Holly to EOF pipelines are not always buried on the beach, which exposes the pipelines to potential impacts by waves and ocean debris, which could cause a failure of the pipeline and subsequent release. The frequency of this event was included separately in the spill frequency analysis by examining the frequency of large wave activity at the offshore buoys and including the frequency of large wave impact and subsequent pipeline failure into the frequency analysis. The Applicant's EOF City of Goleta Permit conditions number 63 and 64 include the following with respect to pipeline inspection in the surf zone.

63. The oil emulsion and gas pipelines shall be visually inspected from the surf zone to the EOF on a daily basis for as long as they are in operation. At a minimum, the following information shall be logged for all inspections: time and date of the inspection; inspector's name; burial status of the pipelines; length of pipe exposed, if any; estimated wave height at the surf; any evidence of pipeline movement. Log reports shall be maintained at the EOF and made available to the County for inspection upon request.

64. Venoco shall shut down and displace the emulsion line with seawater during large storms events (defined as waves measuring more than 12 feet (3.7 m) in height) when more than 20 feet (6.1 m) of the pipeline is exposed. Venoco shall notify [County] P&D of the need to shut down the line immediately upon doing so.

The pipelines were exposed for a period in 2016, as per daily inspections by the Applicant submitted as part of the Compliance Verification Reports (CVRs) to the APCD. The emulsion pipeline was exposed for a period of 624 days during the period between 2000 and 2012, with spans as high as 80 feet.

The CSFM report presents a set of hazardous liquid pipeline incident rates for all pipelines and uses. The CSFM report indicates that the following pipeline design and operation parameters can have a significant effect on pipeline spill rates:

Pipeline age;

Pipeline diameter;

Pipe specification and type;

Operating temperature;

SCADA System;

Cathodic protection system;

Coating type; and

Internal inspection program.

Using the CSFM data, pipeline leak and rupture rates were calculated for the offshore emulsion pipeline. These rates are shown in Table 1.

1.2.3.3 Existing Spill Risk Scenarios Spill Volumes - Platform Holly and Offshore Pipelines

Offshore spill volumes are based on the 2015 SPCC (Venoco 2015) and the 2011 OSCP (Venoco 2011), with adjustments based on a worst-case analysis. The Applicant compiled its SPCC and OSCP as part of the requirements specified by the CCR Title 14 817.02, 40 CFR Part 112 and 40 CFR Part 194, which details the requirements for determining the reasonable worst-case spill volume from platforms and associated pipelines. Both the SPCC and the OSCP provide estimates of the worst case spill volumes.

Spill volumes from Platform Holly are based on the volumes associated with all piping and vessels on the platform along with the volume that could be released from a well blowout. Due to the lack of reservoir pressure and the fact that all wells are operating with gas lift, the blowout scenario would be limited to the flow from the well only during

the time that the gas lift system would depressurize, estimated by the Applicant to be approximately three hours (Venoco 2015). However, the potential for a free-flowing well exists as the OSCP indicates in the OSCP worst case release analysis.

The offshore pipeline release scenario assumes that a rupture of the pipeline could occur at any point along the pipeline, and that the release duration would be either two minutes, as assumed in the Applicant's OSCP, or a worst-case scenario of 60 minutes, as calculated in this EIR. The 60 minute duration was used due to historical releases from pipelines along the California coast. The 1997 Irene pipeline spill lasted for about 60 minutes before the pipeline was shut down.

Release volumes for offshore pipeline spills are complicated by the influence of a range of variables, such as crude oil temperature and density, the depth of the pipeline under the seawater and leak geometry. Portions of the offshore pipeline are deep enough that a leak in the pipeline might produce minimal release volumes. This is due to the hydrostatic pressure of the ocean water potentially being greater than the pressure inside the pipeline. Also, since oil is lighter than water, worst-case release points are located at the top of localized rises in the pipeline, and at landfall. The Federal Bureau of Safety and Environmental Enforcement (BSEE) has developed a pipeline release model name POSVCM (BSEE 2003), which incorporates issues associated with offshore pipelines (i.e., hydrostatic ocean pressure, temperature, etc.) along with the pipeline configuration to estimate the spill release volume.

A range of spill volumes are presented in Table 2, as the spill volume from the pipeline could be a function of a number of different variables. The worst case volume would be the total pipeline volume in combination with the pumping rate over the period between the release and the shutdown of the pipeline. A more probable release volume is characterized by POSVCM model, as shown in Table 2.

1.2.3.4 Spill Risk Scenarios Fate - Platform Holly and Offshore Pipelines

The fate of oil spilled into the marine environment is a function of a number of different variables, primarily wind speed and direction, ocean currents, ocean conditions, and oil characteristics. Models to estimate the fate of oil spills have been developed by a number of different entities, including Bureau of Safety and Environmental Enforcement (BSEE) and the National Oceanic and Atmospheric Administration (NOAA). Additional oil spill trajectories analysis was conducted for this EIR utilizing the BSEE (developed under then MMS) Oil Spill Risk Analysis model (OSRA) and the NOAA GNOME (General NOAA Oil Modeling Environment) model (NOAA 2002). For a discussion of how these models work

Table 2 Offshore Spill Volume Estimates

Spill Scenario	Total Fluids Spill Volume, bbls
SPCC release volume	883
Platform Holly	*719*
Offshore Pipeline	*164*
OSCP release volume	30,811
Platform Holly	30,788
Offshore Pipeline	23
Offshore pipeline modeled case (POSVCM pipeline release)	232
Offshore pipeline worst case (entire pipeline contents plus pumping losses)	812
Worst Case (Holly Inventory plus POSVCM pipeline)	31,020
Worst Case (Holly Inventory plus worst case pipeline)	31,600

Notes: Worst case based on the 60 minute pipeline release. The SPCC spill volume for Holly is only inventory and does not include a blowout release. The OSCP includes a 30 day blowout release also, for a 1,000 bpd well. Total fluids include crude oil and produced water.

Source: Venoco SPCC August 2015, OSCP June 2015 and POSVCM calculations.

The BSEE numerical OSRA model calculates probabilities of shoreline impact, as well as ocean area impact, after applying a drift equivalent to 3.5 percent of the prevailing wind velocity in its trajectory computations. Because of the heavy influence of southward-directed winds near Point Conception, the model results indicate that the probability of shoreline impacts along the Channel Islands to the south from a release in the channel is higher than at sites along the central coast to the north. The influence of southward directed winds in the model effectively overcomes the northwestward surface currents observed over part of the year in the field programs. The BSEE numerical OSRA model results indicate a high probability of spill impacts to the shoreline along the Channel Islands and along the coastline immediately onshore from a release at Platform Holly. A surfzone release from exposed portions of the crude oil emulsion pipeline would respond differently than one far offshore from Platform Holly, with more direct impacts to the shoreline likely.

The OSRA Model utilizes seasonal averaged ocean currents for four seasons: winter, spring, summer, and fall. The seasonally average current fields are provided by Scripps Institution of Oceanography and are based on several years of current meter and free-floating drifter data. Shoreline segments are divided into their respective quad areas and the probability of impact on each quad is calculated. Weathering factors are not addressed since OSRA is entirely drifter-based and assumes a worst case in which the oil would not “weather” and decrease in volume over time.

The use of the seasonal average ocean currents in the OSRA model tends to smooth out the effect of the northward currents, which may occur and thereby reduce the northward movement of the spill trajectories.

The complexity of opposing winds and currents within the Santa Barbara Channel makes the reconciliation between OSRA model results and drifter observations difficult. Because the applicability of the “3.5 percent wind rule” in complex coastal flow regimes has not been rigorously quantified, the GNOME model, which indicates more northward impacts due to its separation of flow regimes, has also been included in this environmental evaluation.

The GNOME model includes variables that account for weatherization of the released materials as well as a set of ocean current regimes for the Santa Barbara Channel. Wind speed and direction as well as variability can be input to the model. This enables the analysis of specific spill situations with given meteorological conditions.

The GNOME model operates by generating “splots” associated with each spill scenario. The fate of the splots is either to remain on the water, to be beached, to be weathered and disappear, or to travel out of the modeling space. The movement of the splots is defined by the ocean current “regime” and the wind influences.

Ocean currents in GNOME are essentially divided into three regimes for the Santa Barbara Channel: upwelling, relaxation and convergent (see Figure 1). Each of these current regimes is shown schematically below.

Figure 1 Schematic Diagrams of Synoptic Circulation Patterns in the Santa Barbara Channel

Source: Harms and Winant 1998.

The upwelling state is named for the upwelling of cold (approximately 52°F, or 11°C) subsurface waters near Point Conception that often accompanies this state. The upwelling state occurs primarily in spring, although it has also been observed in other seasons. In terms of the conceptual models of the momentum balance, the upwelling

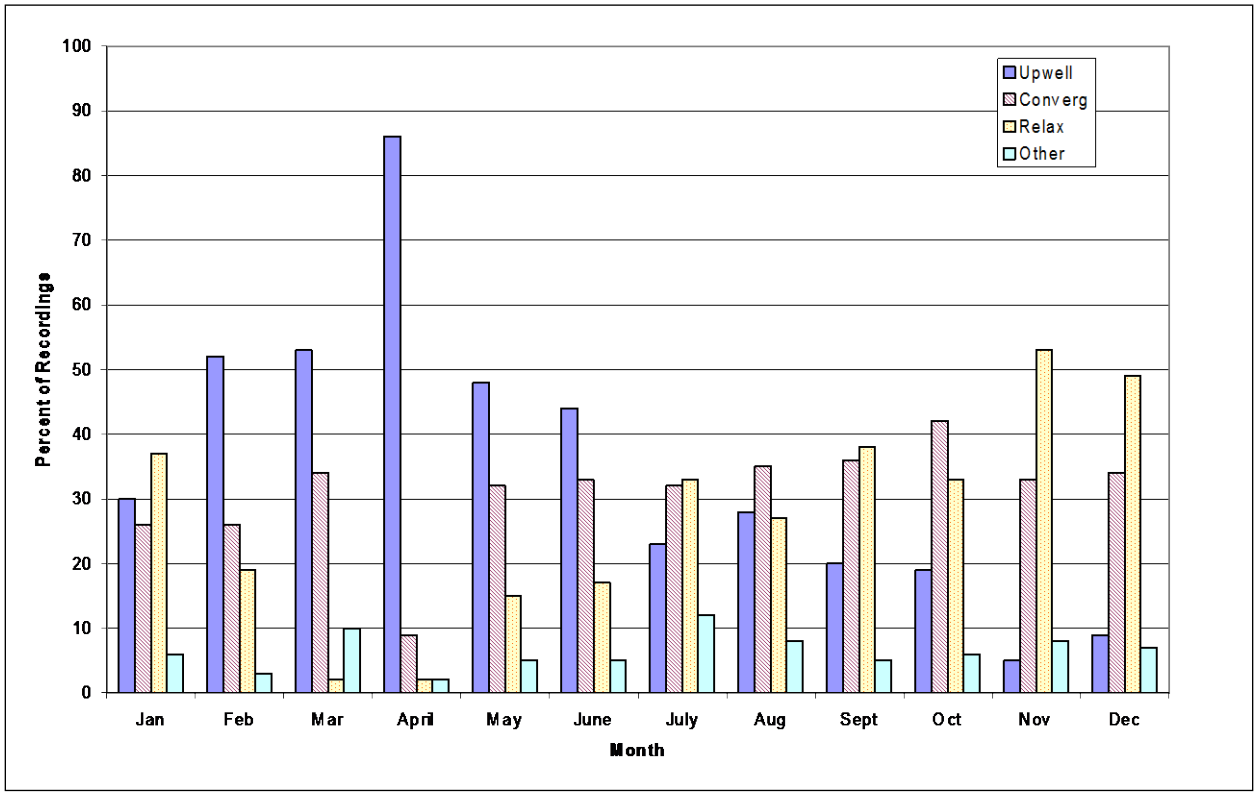
state occurs when strong (>10 m/s), persistent (several days or more), upwelling favorable (equator-ward) winds overwhelm any pole-ward, along-shelf pressure gradient.

The convergent state is named for the convergence of southward flow west of Point Arguello with westward flow south of Point Conception. The convergent state occurs primarily in summer, although it has also been observed in other seasons. In terms of the conceptual models of the momentum balance, the convergent state tends to occur when upwelling favorable winds and a strong pole-ward, along-shelf pressure gradient exist. The most characteristic feature of the resulting flow field is a strong counterclockwise recirculation in the western Santa Barbara Channel with near equal strength in the northern and southern portions of the recirculation.

The relaxation state is named for the time periods when winds off Point Conception “relax” from their usual equator-ward direction. The relaxation state occurs primarily in fall and early winter. In terms of the conceptual models of the momentum balance, the relaxation state occurs when pole-ward, along-shelf pressure gradients overwhelm upwelling favorable or weak winds. The most characteristic feature of the resulting flow field is a strong westward flow through the Santa Barbara Channel and to the west.

Each of the three ocean current states includes a counterclockwise shear in the flow within Santa Barbara Channel. The frequency of occurrence of each flow regime is shown in Figure 2.

Figure 2 Ocean Current Flow Regime Dominance



Source: NOAA GNOME, Santa Barbara Channel. "Other" flow regime correlates to periods when current flows cannot be clearly classified.

The results of the OSRA model are shown in Figure 3. Note that, in Figure 3, during the summer and fall months, an oil spill would generally move towards the west, impacting areas towards Point Conception. The only periods when oil spills might move towards the east is if the spill were to occur during the winter or spring periods. The probability of impacts to the shoreline near Platform Holly (Ellwood, Naples, etc.) would be above 80 percent.

The trajectory analysis presented by the Applicant in their OSCP indicates that a spill could impact areas west to Point Purisma, eastward to Port Hueneme or south to impact the channel islands of San Miguel, Santa Rosa, Santa Cruz, and Anacapa.

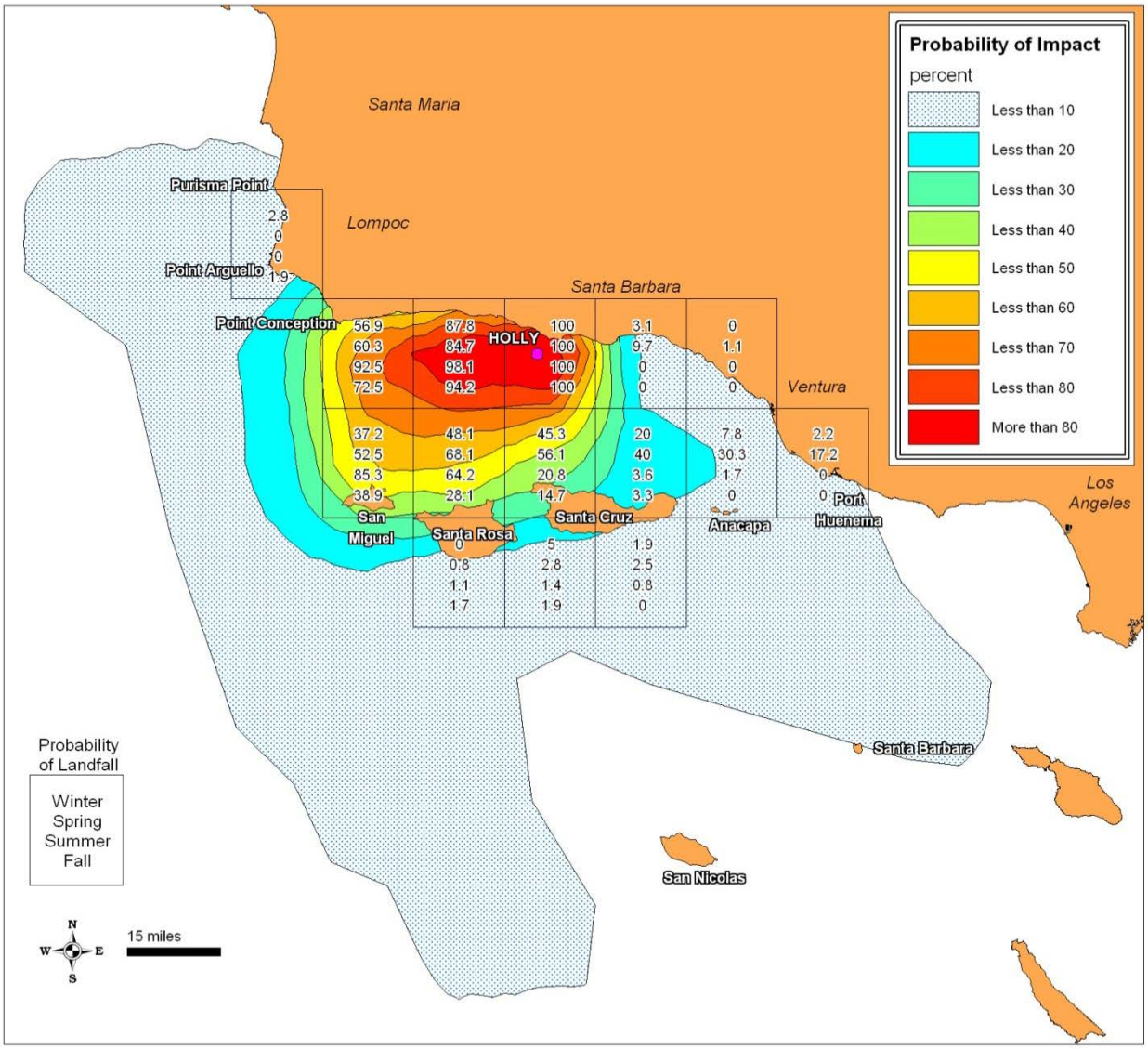
The GNOME analysis allows for an estimate of the amount of oil that might be deposited on beaches from the spill. Table 3 lists the estimated beached volumes of crude oil for the worst-case spill scenario, under existing conditions.

As expected, winds from the south produce the greatest shoreline impact with more than 80 percent of the crude oil being deposited on the beaches for all ocean current flow regimes. Impacts would be along the coast as far north as Point Arguello with winds from the east and convergent ocean currents. Upwelling conditions in

combination with westerly winds could impact the coastline east past Santa Barbara Harbor. Impacts to the Islands could occur with northerly winds and convergent current conditions.

For periods longer than three days, impacts to the coastline and the islands would be more extensive, with spilled oil reaching farther along the coast in all directions, and would impact more islands to the extent shown in the OSRA model Figure 3.

Figure 3 Oil Spill Trajectories, MMS OSRA Model



Source: MMS OSRA model, ten day elapsed time, contours based on annual wind/current average. Some tar balls may extend beyond the zones shown above.

Table 3 NOAA GNOME Model Beached Crude Oil Estimates

Flow Regime	Wind Direction from	Worst Case Beached Volume, bbls	Pipeline Modeled Spill Size Beached Volume, bbl	Location Impacted
Relaxation	North	0	0	Coast to west
	East	2675	20	Coast to west
	South	31,390	230	Coast to west
	West	14,959	110	Coast
Convergent	North	134	1	San Miguel Island
	East	248	2	Coast to west
	South	25,544	188	Coast to west
	West	478	4	Coast
Upwelling	North	19	0	Coast
	East	841	6	Coast
	South	30,549	224	Coast
	West	15,724	115	Coast to east

Note: Based on GNOME model, three day run, no re-float, worst case 31,600 bbls spill, pipeline model case of 232 bbls spill, constant 5 knot wind.

1.2.4 Existing Facility Risks - EOF and Onshore Pipelines

Existing facility risks are primarily related to operations at the EOF, the onshore portions of the Platform Holly to EOR crude oil emulsion and gas pipelines and Line 96, with releases from the PAAPLP pipelines also possible. The immediate public health risks associated with releases of hazardous materials from the EOF that could impact the public through explosions, fires or toxic releases, and the spills of materials that could impact the environment. For the immediate public health risks, release scenarios, the corresponding frequency and impacts of these scenarios and the resulting risk levels are discussed below. Spill risks are discussed in terms of the frequency of spills and the corresponding consequences or spill volumes.

Spill risks associated with the Line 96 pipeline from the EOF to the PAAPLP tie-in were discussed in the Line 96 Modification Project EIR (County of Santa Barbara 2011), which found that operation of the pipeline would have the potential for an oil spill that could result in a significant impact to the environment (refer to impact HM-3). Although implementation of mitigation measures in that EIR would reduce impacts through the installation of automated block valves and a check valve, thus reducing a potential worst case spill volume, potential impacts were still classified as significant. The EIR looked at the potential spill volumes associated with the then existing operations of 2,525 bpd of crude oil (as per Table 2-1 in the 2011 EIR). The Line 96 pipeline has been examined in this EIR for potential increases in spill volume and therefore spill risk. The Line 96 EIR identified the maximum Line 96 spill volume of 237 bbls.

Spill risks associated with the transportation through the PAAPLP, were not assessed in the SBC 2011 EIR, yet it would also be used to transport crude oil associated with the proposed Project. The PAAPLP tie-in is located near the entrance to Las Flores Canyon (LFC), approximately 8.5 miles west of the EOF. The PAAPLP pipeline is currently shut in as on May 19, 2015, a portion of the PAAPLP pipeline ruptured, spilling approximately 2,400 bbls of crude oil onto surrounding soils and into culverts and drainages. Approximately 500 bbls of this spilled oil reached the marine environment and directly impacted approximately nine miles of coastline extended along the Gaviota, Ellwood and Goleta and Santa Barbara Shorelines. However, residual oil reached much further, with tar balls reaching as far south as Hermosa Beach in Los Angeles (a distance of more than 100 miles).

The impacts of construction and operation of the PAAPLP pipeline was addressed in a certified EIR (CSLC 1985) that concluded significant impacts to soils, surface water, groundwater, aquatic biology, terrestrial biology and land use and recreation. Impacts to aquatic biology included impacts due to oil spills. This EIR found that such spills could result in "potential reduction in abundance of intertidal invertebrates, surface-feeding fish, and shorebirds in near shore marine areas" due to a major spill into coastal streams. The throughput examined in the 1985 EIR was for up to 150,000 bbls for the Coastal Branch of this pipeline along the Gaviota Coast, substantially more than recent pre-shut in 2014 transport volumes.

1.2.4.1 Immediate Health Risks of Hazardous Materials - EOF and Onshore Pipelines

A range of scenarios were developed in consideration of the existing EOF immediate public health risks. Scenarios are associated with the EOF and the Platform Holly-EOF pipelines (gas and emulsion) between the beach and the EOF. Each of these scenarios is discussed below.

Existing Release Scenarios - Ellwood Onshore Facility

The EOF could have a release of sour gas or flammable materials that could impact the public health of nearby populated areas, could have a release of crude oil that could ignite and cause impacts to public health, or could drain to the ocean or creeks and cause impacts to the environment.

Descriptions for the EOF release scenarios are presented below as described in the SBCFD QRA (SBCFD 2000). Additional scenarios have been added to address the risks of oil spills and to update the SBCFD QRA to existing operating conditions.

1. Loss of containment from the gas pipeline on the beach to the plant inlet

This scenario includes a release from the section of pipeline running under or on top of the beach to the EOF. The scenario assumes a release of the entire contents of the gas

pipeline. This release was modeled by assuming that a crater forms as the pipeline is usually located underground. The cratering effect is caused by the released gases impacting the side of the crater, thereby slowing down dispersion and increasing the hazard distances.

2. Loss of containment at inlet separation, LOCAT gas side and first stage suction

This scenario encompasses all the gas streams within the EOF from the pig catchers to inlet separation through the H_2S LOCAT system to the first stage suction scrubber. The gas inlet separation system is located in the center of the EOF and the LOCAT system is located at the northern end of the EOF. Possible release causes would be valve, piping, vessel failure or failure of pigging operations. A release would consist of methane and hydrogen sulfide. It was conservatively assumed that the entire system contains H_2S at inlet concentrations and operates at first stage suction temperature and pressure. Possible consequences include flame jet, flammable dispersion leading to a deflagration or vapor cloud explosion, and toxic dispersion.

3. Loss of containment at compressor K-201 stages one and three

The K-201 compressor is located along the fence on the northeastern EOF boundary within the EOF. A release could result from a compressor failure in combination with an automatic shut-down failure; or piping, heat exchanger or valve failures releasing high-pressure methane. Possible consequences include flame jet, flammable dispersion leading to a deflagration, or vapor cloud explosion. As there is no H_2S in the gas stream at this point, there would be no toxic vapor dispersion.

4. Loss of containment at the compressor second stage and glycol separator

The glycol separation system is located in the northeastern corner of the EOF within the EOF. Pipe, valve, heat exchanger, or vessel failure could result in a release. The release would consist of primarily methane gas. Possible consequences include flame jet, flammable dispersion leading to a deflagration, or vapor cloud explosion. As there is no H_2S in the gas stream at this point, there would be no toxic vapor dispersion.

5. Loss of containment at LPG and NGL storage and truck loading

The LPG and NGL storage vessels are situated near the center of the EOF. The storage vessels are offloaded to truck tankers for transportation offsite. Existing operations involve only LPG loading as almost all of the NGL is loaded into the crude oil for pipeline transportation. Although levels have varied over the last five years, there was only one NGL truck loaded in 2014. This scenario considers failure of the liquid gas storage systems and also the equipment failure and operator errors that could cause a release during loading operations. Possible consequences include flame jet, vapor cloud dispersion resulting in deflagration, or explosion, or, in the case of impinging

flame jet on one of the storage bullets, a boiling liquid expanding vapor explosion (BLEVE).

6. LPG Stabilizer and Storage

The LPG stabilizer is located in the northeast section of the EOF. This scenario would involve an equipment failure in the piping or valves or from the exchangers or vessels. Possible consequences include flame jet, vapor cloud dispersion resulting in deflagration, or explosion.

7. Release from Produced Water or Crude Oil Tank Vapor Space

The produced water tank and crude oil tanks are located in the middle of the EOF. The vapor space in the tank contains gas with a high H_2S content. A release from these tanks could cause toxic dispersion. Also, as the tanks are blanketed with methane gas, a release could also produce a flammable vapor cloud.

8. Crude oil releases from drain system

Crude oil releases could result from equipment failures at the crude oil pig catcher; loss of containment at heater treaters and H_2S strippers; or the crude oil tanks, pumps or meters. The entire EOF is protected by berms, which direct storm water and any spills to sumps. The sumps are periodically emptied by discharging the sump contents to the ocean outfall system. The contents of the sump are tested for hydrocarbons before being discharged. In the event of an operator error, such as not testing or leaving the discharge system open after the previous dump, combined with a spill from the processing equipment, a release of crude oil could impact the environment. This scenario would not, in and of itself, result in a release of crude oil, but would allow a release from process equipment to reach the ocean. It is therefore considered to be a contributing event to a release of crude oil to the ocean and is included in the frequency analysis.

9. Propane releases from the refrigeration system

Propane releases could result from failures at the EOF propane refrigeration system and propane storage tank. This scenario would involve an equipment failure in the piping or valves or from the exchangers or vessel. Possible consequences include flame jet, vapor cloud dispersion resulting in deflagration, or explosion.

10. Releases from the Line 96 Pipeline System

Releases from the Line 96 pipeline system could impact areas onshore, including perennial streams designated as ESHAs, and in the marine environment if crude oil is spilled and drains down gullies and creeks to the marine environment. Such impacts to

the marine environment as occurred in May 2015 when the PAAPLP pipeline spilled just west of the Line 96 location. Spill risks associated with the pipeline from the EOF to the PAAPLP Coastal Branch tie-in were discussed in a certified EIR (SBC 2011).

Existing Release Scenario Frequencies - Ellwood Onshore Facility

In the 2000 QRA prepared for the Santa Barbara County Fire Department, 41 release scenarios were developed for the EOF (SBCFD 2000). These scenarios have been updated to address changes at the EOF since the preparation of the SBCFD QRA, including the following:

- Reduced use of the NGL loading system due to crude oil/NGL mixing for pipeline transport;
- Reduced use of the LPG/NGL storage vessels;
- Elimination of the debutanizer; and
- The inclusion of the SBCFD mitigation.

Scenario frequencies are shown in Table 4 below. Only those scenarios which could cause offsite impacts are listed.

Table 4 EOF Release Scenario Frequencies

Scenario	Frequency, per year	Years between Release
Pipeline - beach rupture	1.26×10^{-5}	79,365
Pipeline - beach leak	1.47×10^{-3}	681
Gas processing rupture	1.22×10^{-4}	8,230
Compressor K201-3 rupture	9.64×10^{-5}	10,373
Compressor K201-2 rupture	3.92×10^{-5}	25,510
LPG and NGL loading rupture	8.71×10^{-6}	114,767
LPG storage rupture	1.16×10^{-7}	8,620,690
LPG and NGL storage leak	2.00×10^{-5}	50,000
LPG stabilizer rupture	6.40×10^{-5}	15,625
Flare release	4.34×10^{-5}	23,041
Produced water tank release	2.64×10^{-3}	379
NGL storage rupture	1.76×10^{-7}	5,681,818

Source: SBCFD 2000 (2000 QRA) with modifications

The 2000 QRA reviewed safety issues and hazards associated with the EOF operating at full permitted capacity of 13,000 BOPD and 13,000 mscfd of natural gas. Although most of the existing operations would be the same as those analyzed in the 2000 QRA, some currently out of service equipment were included in the 2000 QRA analysis,

including the debutanizer. This equipment was not included in this analysis because it is not in use under existing operations and it is not proposed to be in use as part of the proposed Project. The frequency of LPG/NGL truck trips in the 2000 QRA was assumed to be 470/yr. LPG/NGL shipments in 2014 totaled 126 trips. Therefore, the LPG/NGL trips were decreased for this analysis. These factors, along with others, account for the differences between the 2000 QRA results and the existing analysis results.

Frequencies of a release from the Line 96 pipeline were addressed in a previously certified EIR and are not expected to change (SBC 2011). Spill frequency for the Line 96 was estimated to be once every 31 and 140 years (for small and large releases respectively) in the 2011 EIR.

Existing Release Scenario Consequences - Ellwood Onshore Facility

Consequences of a release involve determining the area where, if a release occurs and a person is located within that area, that person would experience serious injuries or fatalities. One of the first steps in determining the consequence of a release is to establish the release rate associated with each scenario. The release rate is the rate at which the material is released from the pipe and/or vessel to the atmosphere. Before the release rates can be estimated for each scenario identified in the hazard analysis, the thermodynamic and physical properties of each hydrocarbon stream need to be characterized. Estimation of the thermodynamic and physical properties of the hydrocarbon streams was accomplished using the IoMosaic SuperChems© model, which utilizes numerous thermodynamic and physical property estimation techniques.

The SuperChems© model is able to simulate the release of multi-component liquid/vapor streams, which are characteristic of the potential releases associated with the facility. For this study, these models are useful in assessing the effect of multi-component streams on vapor cloud flammability characteristics.

Vapor and Toxic Cloud Dispersion Distances

For releases of material producing vapor clouds, both flammable and toxic vapor clouds, determining how the release behaves in the air downwind of the release is called dispersion analysis. Initially, the density of the release affects the dispersion process. A buoyant release may increase the effective height of the source. By the same token, a heavier-than-air release will slump towards the ground. For heavier-than-air releases at or near ground level, the initial density determines the initial spreading rate. This is particularly true for large releases of liquefied or pressurized chemicals, where flashing of vapor and formation of liquid aerosols contributes to the initial effective vapor density, and therefore to the density difference with the air. This is particularly true for gas releases where significant cooling of the released material occurs due to expansion of the gas from the pipe pressure to atmospheric pressure.

Results of research programs (CCPS 1989, Lee 1996) indicate the key importance of heavy gas dispersion in the area of chemical hazard assessment. The initial rate of spreading for heavy or cooled gases is large, and is dependent on the differences between the effective mean vapor density and the air density. The rapid mixing with ambient air due to slumping leads to lower concentrations at shorter distances than those predicted using neutral density dispersion models. There is very little mixing in the vertical direction, and, thus, a vapor cloud hugging the ground is generated. When the mean density difference becomes small, the subsequent dispersion is governed by prevailing atmospheric conditions. Since heavy gas dispersion occurs near the release, it is particularly important when considering large releases of pressurized flammable chemicals.

In addition to the effects of initial release density, the presence of aerosols, release rate/quantity, release duration, and mode of release, dispersion analysis also depends on:

- Prevailing Atmospheric Conditions: Include a representative wind speed and an atmospheric stability class. Less stable atmospheric conditions result in shorter dispersion distances than more stable weather conditions. Wind speed affects the dispersion distance inversely. Because weather conditions at the time of an accident cannot be determined a priori, two weather conditions are used for both a typical and a worst-case weather condition

- Limiting Concentration: The concentration at which human health effects would begin to occur. It affects the dispersion distance inversely. Lower concentrations of concern lead to larger dispersion distances. As with source release rate, the effect is non-linear. For example, for steady state releases, a factor of 100 reduction in the limiting concentration results in an increase in the dispersion distance by a factor of approximately ten.

- Elevation of the Source Elevation: Attributed to the physical height of the source (such as a tall stack). In general, the effect of source height is to increase dispersion in the vertical direction (since it is not ground restricted) and to reduce the concentration at ground level.

- Surrounding Roughness and Terrain: Affect the dispersion process greatly. Roughness is defined as involving trees, shrubs, buildings and structures, while terrain is defined as hills and general topology. Roughness usually enhances dispersion, leading to a shorter dispersion distance than predicted using a smoother, or lower, roughness factor.

- Source Geometry: Refers to the actual size and geometry of the source emission. For example, a release from a safety valve may be modeled as a point source. However, an evaporating pool may be very large in area and may require an area

source model. Source geometry effects are large when considering near field dispersion (less than ten times the characteristic dimensions of the source). At farther distances, the source geometry effects are smaller and eventually become negligible.

- Jet Effects. The jet effects of a gas released from a pressurized source entrain large amounts of air. This entrained air causes more rapid dilution of the streams and, in combination with temperature and density effects, which subsequently results in smaller hazard zones. Jet effects can reduce hazard zone estimates by up to 50 times over the simplified Gaussian estimates (CCPS 1989, Lee 1996). Given the extensive field validation of the effects of jets and near-field air entrainment, the jet models are a more realistic estimate of hazard distances than the simplified Gaussian models.

Several mathematical variations are included in the models used in this analysis. They have also been computerized as part of the IoMosaic SuperChems© modeling package for ease of use. Additional models, which are available in the public domain and have been rigorously evaluated, were also used including the SLAB model. The SLAB model includes the effects of air entrainment into high speed jets of gas, the gravity effects on cold dense gases, which cause the cloud to slump and spread, the warming of the cloud, and the transition to a passive Gaussian dispersion.

Flame Jets and Thermal Radiation

The flame jet model, as a part of SuperChems©, is designed to simulate turbulent diffusion flames (flame jets) and can characterize the flame length, diameter, temperature, and thermal radiation effects. This model is capable of simulating inclined turbulent jets, radiation fields, and the aerodynamic effects on radiant energy and flame stability. This model was used for all scenarios where high pressure, potentially flammable vapor releases were identified.

Vapor Cloud Fire and Explosions

Vapor cloud fires and explosions could occur if a release of flammable material produces a flammable vapor cloud, which encounters an ignition source. The potential for unconfined vapor cloud fires and explosions was assessed using the IoMosaic SuperChems© model. The difference between a fire and an explosion is primarily the rate at which the cloud burns. The potential for a vapor cloud explosion versus a vapor cloud fire was assessed based on the physical characteristics of the hydrocarbon stream (CCPS 1994). Parameters that influence the potential for, and consequences of, a vapor cloud explosion include:

- Characteristics of ignition sources;
- Flame acceleration mechanisms;

- Deflagration to detonation transitions;
- Direct initiation of detonations;
- Overpressure levels within the combustion zone;
- Effects of pressure rise time dependency on structures vs. TNT curves;
- Minimum amount of mass sufficient to sustain an Unconfined Vapor Cloud Explosion (UVCE);
- Partial vapor cloud confinement and flame reflection characteristics; and
- Explosion efficiencies.

This model was used to assess whether or not enough flammable mass could accumulate to sustain an explosion (a relatively large amount of flammable mass is required for the flame front in the vapor cloud to gain sufficient speed to result in a pressure wave within the vapor cloud). In most cases, the amount of flammable mass or the levels of confinement were not sufficient to sustain an explosion. In other cases, modeling results showed that vapor cloud ignition would be characterized by a deflagration (i.e., sub-sonic flame velocity), producing a fire, and would not transition to a full detonation (i.e., supersonic flame velocity).

BLEVE

A boiling liquid expanding vapor explosion, or BLEVE, is a sudden loss of containment of a liquid that is above its boiling point (at atmospheric conditions). A BLEVE results in a sudden, vigorous liquid boiling and the production of a shock wave and a flame front (if an ignition source is encountered and the material is flammable). Liquids stored under pressure (such as the gas liquids) fall into this category, as well as any liquid that is stored at an elevated temperature above its boiling point. The main hazards presented by liquids stored under pressure are overpressure, fireball, and thermal radiation (CCPS 1994).

BLEVEs were modeled using the SuperChems© model for fireballs. The approach is to estimate the total energy that could be produced by the material combustion and to estimate the duration of the explosion. Impacts are estimated by integrating the energy flux over the time that the explosion occurs at different distances from the source of the explosion. Overpressure due to BLEVE was also estimated assuming the vessel fails due to overpressure, and the resulting shockwave is dissipated to the environment. The larger of the hazard zones pertaining to BLEVEs (either overpressure or thermal radiation) was used to estimate risk.

Limiting Concentration/Levels of Concern

Limiting concentration criteria were developed in order to quantify the potential consequences of an accidental release. Limiting concentration criteria are developed for exposure levels that could produce both fatalities and serious injuries. Serious injury is defined as an impact from the exposure that could require medical intervention and could produce effects that last significantly longer than the duration of the exposure. The Santa Barbara County Safety Thresholds define injury to be a serious injury when it causes physical harm to a person that requires significant medical intervention. An injury, such as lung damage, that would require hospitalization and/or other types of therapy would be considered a serious injury.

The emergency response planning guidelines (ERPG) values were used to define the "major" or lower limit of fatalities and the "serious injury" health effects for toxic exposure for H_2S. The ERPG values are listed below.

ERPG-3 (100 ppm H_2S) The maximum airborne concentration below which it is believed that nearly all individuals could be exposed for up to one hour without experiencing or developing life threatening health effects.

ERPG-2 (30 ppm H_2S) The maximum airborne concentration below which it is believed that nearly all individuals could be exposed for up to one hour without experiencing or developing irreversible or other serious health effects or symptoms, which could impair an individual's ability to take protective action.

ERPG-1 (0.1 ppm H_2S) The maximum airborne concentration below which it is believed that nearly all individuals could be exposed for up to one hour without experiencing other than mild, transient adverse health effects, or without perceiving clearly defined objectionable odor.

The lower limit of fatalities and the value at which it was assumed that all persons exposed would realize a serious injury was established as the ERPG-3 value. The value at which serious injuries would start to be realized was determined to be ERPG-2. As needed, the fatality and serious injury values were scaled to the appropriate exposure time using the "Probit" equation method.

Deflagration of the vapor cloud would produce impacts to persons located within the flammability limits of the vapor cloud. Persons located within the lower flammability limit (LFL) would most likely suffer at least serious injuries. As there is some natural variability within the cloud, it is assumed that persons located within the area that would be encompassed by a level of concern equal to one-half the LFL (a larger area than the LFL area) would suffer serious injuries.

An overpressure level of 0.3 psi would likely result in broken windows and some potential for serious injury. This overpressure level has also been established as the

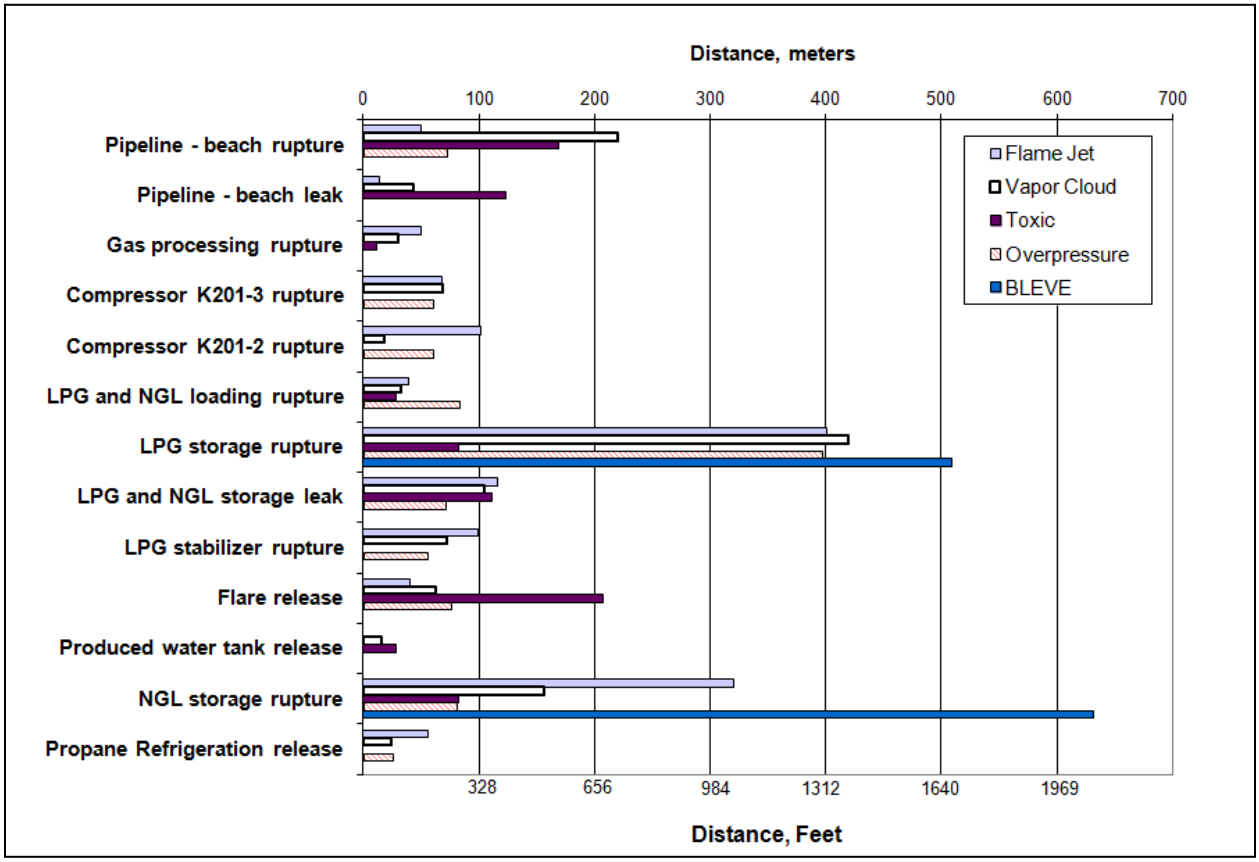
outer limit of debris being thrown from an explosion (CCPS 1994). Complete structural damage and serious injuries and fatalities could occur for wooden buildings and non-reinforced masonry as a result of exposure to an overpressure level of 1.0 psi (CCPS 1994, 1996).

The time required to reach pain, second degree burn, and fatality thresholds was used to estimate radiation levels that would result in serious injury or fatality. Persons exposed to thermal radiation have the opportunity to move away from the hazard, unlike overpressure effects or vapor cloud fires/explosions, which are instantaneous. It was assumed in this analysis that some people not within the flame area would move to a safe location, away from the flame, in less than one minute. Therefore, a less than one minute exposure was used as the basis for determining the levels of concern. Exposure to a thermal radiation level of 10 kW/m^2 could result in a serious injury (at least second degree burns) if exposed for less than one minute, and it was therefore assumed that all persons exposed to 10 kW/m^2 would suffer serious injuries. Serious injuries would start to be realized at and above 5 kW/m^2. Exposure to thermal radiation levels in excess of 10 kW/m^2 would likely begin to generate fatalities in less than one minute.

For more information on modeling and damage criteria, refer to the Venoco QRA (Appendix R, SBCFD 2000).

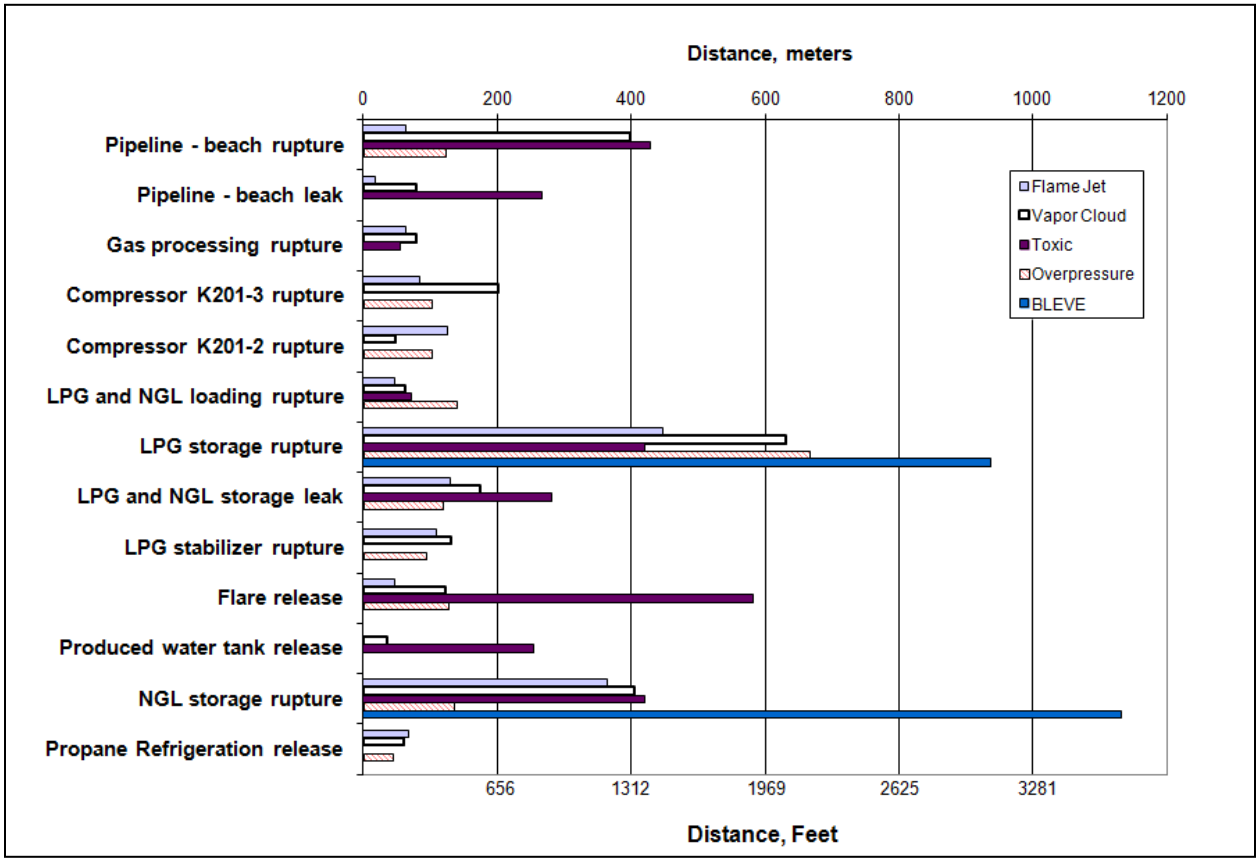
Impacts related to the gas releases at the EOF were detailed in the SBCFD QRA (SBCFD 2000). These impact distances are shown in Figure 4 and Figure 5. The largest impacts are associated with releases from the LPG and NGL storage tanks, followed by pipeline beach releases and flare releases.

Figure 4 EOF Scenarios Fatality Zones



Source: SBCFD 2000

Figure 5 EOF Scenarios Injury Zones



Source: SBCFD 2000

The 2000 QRA assumed that the EOF was operating at the permitted capacity of 13,000 BOPD, including H_2S limits of 20,000 ppm. Therefore, impact zones as calculated in the 2000 QRA is a conservative estimate the impacts of existing operations at the EOF. Both existing (pre shut-in) crude oil and gas throughput are substantially lower than the permitted capacity. However, impact zones are a function of the pressure in the system and the system inventory more than the throughput, so despite substantially lower throughput, impact zones for existing operations would be similar to those detailed in the 2000 QRA. Gas liquids inventories under existing recent operations are lower than the QRA as only one NGL and one propane (LPG) tank is currently in service. Therefore, frequencies of a release from the gas liquids system under existing operations would be lower. However, impact zones associated with a release from a single tank would be the same currently as in the 2000 QRA.

1.2.4.2 Existing Public Health Risk Analysis - Ellwood Onshore Facility

A risk analysis involves combining the scenario frequencies with the consequences and the numbers of persons that could experience serious injuries or fatalities from each scenario. These are combined to produce “Fn curves” or “risk profiles,” which depict the

frequency of experiencing a scenario which causes a given number of fatalities or injuries. Santa Barbara County agencies have developed criteria which define the acceptable and unacceptable numbers and frequencies of fatalities and injuries (see regulatory section below). In calculating the Fn curves, a two-dimensional computer map of the area was prepared. The population distribution and probabilities of ignition were specified across the area of the map; and the likelihood of an individual fatality or serious injury was calculated at each grid location on the map.

To develop the Fn curves, many factors were considered. Each release scenario was evaluated for all wind directions and for each combination of stability and wind speed. In any given direction, it is necessary to consider the chances of having the particular wind stability class, the cloud igniting at the facility, and the cloud igniting offsite at every downwind receptor location on the map. The frequency of attaining the maximum downwind distances for flammable vapor dispersion would be reduced if the vapor cloud encounters ignition sources at the point of release or at any point along its travel path.

Atmospheric stability classes D and F were selected as characteristic wind stability conditions. The F stability class represents periods of calm during the nighttime, when wind speeds are low and dispersion would be minimal. The D stability class is less stable and represents the daytime conditions with some wind speed. Based on wind speed conditions for these stability classes, a wind speed of 5.0 meters per second (m/s) was selected for stability class D neutral atmospheric stability, while a wind speed of 2.0 meters per second (m/s) was selected for stability class F (stable atmospheric conditions). The predominant conditions are generally wind from the west and west-south-west direction, although wind frequencies from all directions were used in the analysis. Wind in the predominant direction and wind from other less predominant directions were assigned their respective frequencies of occurrence based on historical wind data. Wind data were based on the Santa Barbara APCD LFC-10 Station meteorological data from 1988 to 1998.

Refer to the Venoco QRA prepared in 2000 for more details on the QRA assumptions (SBCFD 2000). Although many aspects of the 2000 QRA were utilized in this analysis, the 2000 QRA assumed that the Sandpiper Golf Course had completed its expansion plans, and that the Sandpiper residential development project had been completed. These items were not included in this analysis as neither the expansion nor the development project have been completed. Also, traffic and population numbers were updated.Population information in the vicinity of the Applicant’s site was gathered for locations and within at least 3,000 feet (0.9 km). These included the following:

- Highway 101;
- Hollister Avenue;
- Calle Real Road;

- Bacara Hotel Spa and Resort;
- Access road to the Bacara Hotel Spa and Resort;
- Sandpiper Golf Course;
- Residential areas North of Highway 101; and
- Beach areas.

Populations at these areas were entered into the QRA Model in the grid system. It was assumed that residential houses contained a population of 3.6 persons per household as per the Census data for the respective census block group. Table 5 shows the population of locations near the EOF.

Table 5 Population of Locations Near the EOF

Location or Road	Distance from EOF	Population	Trips
Bacara Resort and Spa	Xx feet west	1,300 people	n/a
Tennis and Public Beach	1,300 feet west	165 people	n/a
Sandpiper Golf Course	75 - 1,000 feet east (clubhouse 1,000 feet, 1th hole fairway as close as 75 feet)	80persons at the clubhouse 200 personson the course itself)	n/a
Ellwood Elementary School	4,300 feet east	447	n/a
Bacara Resort and Spa Access Road	Adjacent to the north	n/a	5,300
US Highway 101	300 feet north	n/a	35,000

Flammable vapor clouds have the potential to ignite anywhere within their flammable limits. Hence, it is necessary to identify potential ignition sources that a cloud may encounter, and to quantify the likelihood of ignition, if the cloud encompasses the sources. When determining ignition probabilities, there are two factors to take into account; first, source duration, the fraction of time that the source is present or in operation; and second, source intensity, the chance of the source actually causing ignition if contacted by a flammable cloud. For example, if a ground level flare is operating, it will almost always ignite a vapor cloud. But it may only operate 10 percent of the time. Therefore, this would produce an overall chance of ignition of the vapor cloud by the ground level flare of 0.1, or 10 percent.

In general, when trying to identify ignition sources, the search is primarily for open flames, hot surfaces and electrical sparks, and, to a lesser extent, friction sparks from

both continuous and intermittent activities (CCPS 1989, UK 2004). Estimates of ignition probabilities from some of these sources are also provided.

Typical ignition probabilities that were used in the analysis include:

- Cars - 0.06 per car; although many potential ignition sources within a car like faulty wiring or backfires are due to fuel rich mixtures in intake air, they are not always present nor guaranteed to cause ignition. This value was also applied to golf carts (CCPS 1989);
- Houses - 0.01 per house; while there are many ignition sources within a home, such as switches, doorbells, faulty wiring, pilot lights, smoking materials, fireplaces and wood or coal burning stoves. The flammable vapors must first penetrate the house before these ignition sources pose a hazard. Typical residence times of clouds are often brief enough that this is relatively unlikely (CCPS 1989); and
- Industrial Areas – 0.1 for light industrial, 0.25 for medium industrial and 0.5 for heavy industrial areas. Heavy industrial areas are classified as having large motors, high temperature surfaces and open flames (UK 2004).

In order to estimate the number of vehicles, traffic counts for particular roads were used along with estimated average speeds to determine the density of vehicles per mile.

Ignition sources within the EOF included the thermal oxidizers/flares and the heaters, both of which have internal open flames. Additional sources include pumps and blowers, compressors and non-classified electrical areas. The thermal oxidizers/flares and the heaters were assumed to present a 90 percent chance of igniting a flammable vapor cloud. The remainder of the EOF was conservatively assumed to present a one percent chance of igniting a flammable vapor cloud due to pumps, blowers, compressors, and non-classified electrical systems.

Event trees are used to determine the fate of a released material after the release has occurred. A release of a flammable material, for example, could experience instantaneous ignition leading to a flame jet. It could also disperse downwind and encounter an ignition source and burn or explode, or it could disperse safely. For larger releases, it was assumed that immediate ignition would occur 25 percent of the time and for the remaining time (75 percent) that the vapor cloud would disperse downwind to have explosive/fire or toxic impacts depending on the downwind ignition sources. For smaller releases, the percentage would be 10 percent (CCPS 1989).

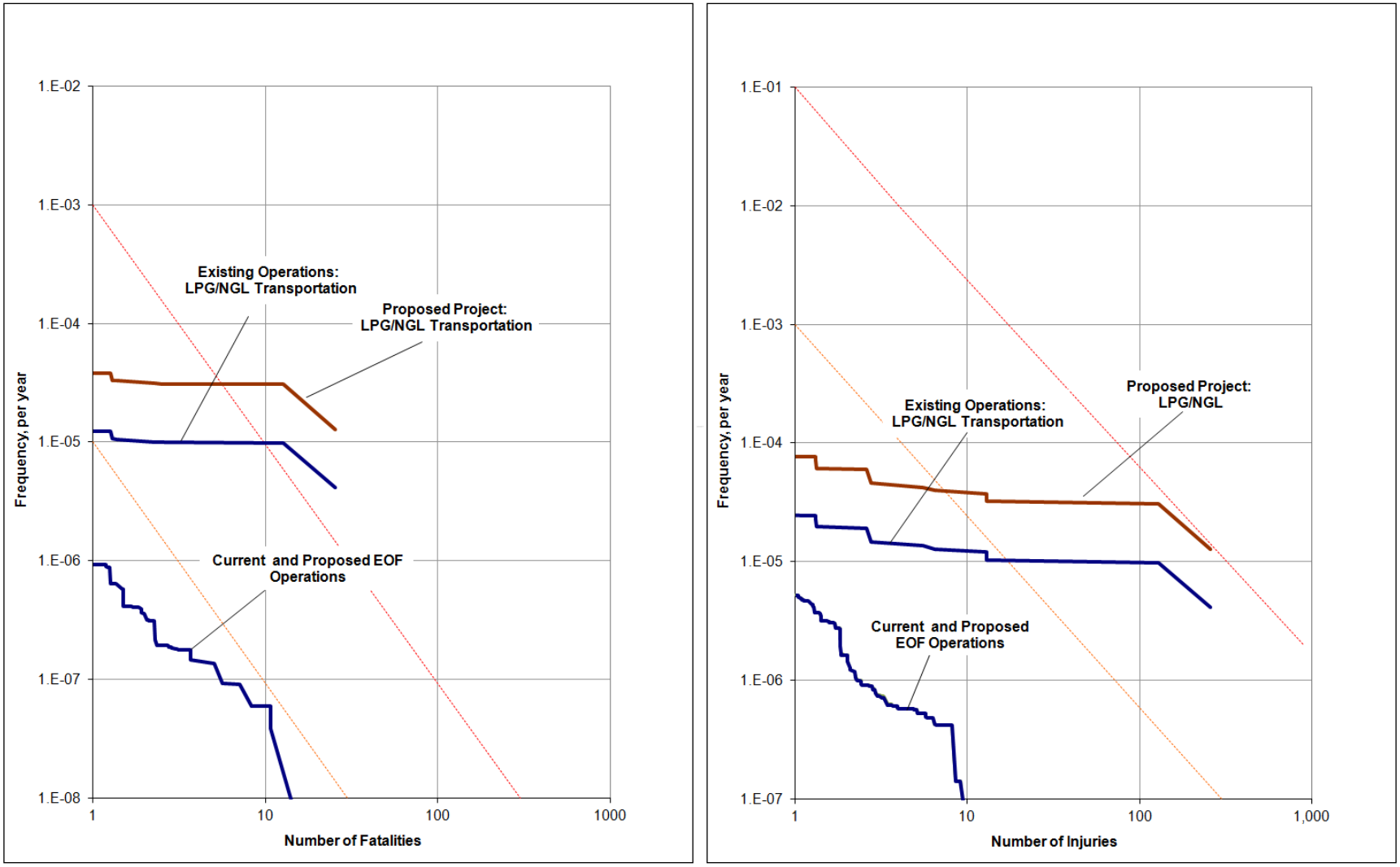
Note that if the release is not immediately ignited, it can produce a toxic cloud (assuming H_2S content) until it is ignited or remains unignited. After ignition, it is assumed that the plume rises and any residual H_2S or combustion byproducts (sulfur oxides [Sox]) would rise due to thermal effects and not present a hazard.

The 2000 QRA estimated Fn curves for the facility. This analysis has updated the assumptions and inputs to the Fn curves and has used a different model to calculate the curves. Therefore, the Fn curves would not be expected to match exactly. However, they both fall into the acceptable region of the SBC criteria and are shown in Figure 6.

Included on the Fn curves are the curves associated with transportation of the LPG/NGL to Bakersfield. Transportation curves are normally higher than fixed facility curves due to the increased accident rates associated with transportation of liquid cargo as opposed to static storage. Transportation risks are estimated using a transportation risk model developed by MRS, which includes traffic volume data, accident rates, conditional probabilities of release, population data, and consequence modeling results. Accident rates were determined for trucks along the specific route segments by examining the accident data provided by CalTrans. Conditional probabilities of a release of material or of producing a trauma-related serious injury or fatality were obtained from California Highway Patrol databases for truck accidents. The analysis relied heavily on a Santa Barbara county study titled “Nuevo LPG Transportation Risk Assessment” (SBC 2004).

Also shown in Figure 6 are the curves associated with the proposed Project, to be discussed later in this section.

Figure 6 Fn Curves



1.2.4.3 Spill Risks - Ellwood Onshore Facility

The largest vessels at the EOF that contain crude oil are the crude oil storage tanks, which have a capacity of 2,000 bbls each and the 1,200 bbls heater treaters. Additional vessels with liquid inventory include the 3,000 bbls produced water tank, and the 2,000 bbls reaction and oxidation tanks in the H_2S removal unit. A failure of the tank/vessel or a rupture of piping or one of the smaller, connected vessels/systems could cause a release of the contents to the containment/sump system, which could be released to the ocean outfall if appropriate procedures and methods are not followed.

Spills at the EOF would generally be contained onsite by the berms and drainage systems. All EOF drains are directed to the facility sump. The sump system is periodically pumped to the ocean through the ocean outfall. The Applicant indicates that the fluids are tested for hydrocarbons before draining. If these drain valves or pump lines were left open after one of these drainings, and the status of the open drain valves was not noticed in a subsequent inspection/operator round, and a catastrophic release of crude oil occurred, a spill could reach the ocean. Because of the use of a sump, drain valves and inspections, the existing operations frequency of a release impacting the areas outside the EOF and the ocean is estimated to be less than once every one million years.

Spill impacts from a release from the ocean outfall would be similar to the trajectory analysis described above for releases from Platform Holly or the offshore pipeline, with impacts being a function of the size of the spill along with the corresponding current and wind conditions.

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Acronyms/Abbreviations

ACCM	Asbeston containing construction materials
ACM	Asbestos containing materials
AIChE	American Institute of Chemical Engineers
ANSI	American National Standards Institute
API	American Petroleum Institute
ARP	Accidental Release Plan

ASME	American Society of Mechanical Engineers
ASTM	American Society for Testing and Materials
bbl	barrel
BLEVE	Boiling liquid expanding vapor explosion
BOEM	Bureau of Ocean Energy Management
bpd	Barrels per day
BSEE	Bureau of Safety and Environmental Enforcement
CA	Coastal Act
CalARP	California Accident Release Prevention Program
CCR	California Code of Regulations
CHP	California Highway Patrol
Corps	U.S. Army Corps of Engineers
CSLC	California State Lands Commission
CSFM	California State Fire Marshall
CUPA	Certified Unified Program Agencies
CVR	Compliance Verification Report
DOD	Department of Defense
DOGGR	Division of Oil, Gas, and Geothermal Resources
DOI	Department of the Interior
DOT	Department of Transportation
DOT	Department of Transportation
DTSC	Department of Toxic Substances Control
EAP	Emergency Action Plan
EOF	Ellwood Onshore Oil and Gas Facility
EPA	Environmental Protection Agency
EPCRA	Emergency Planning and Community Right-to-Know Act
ERNS	Emergency Response Notification System
ERPG	Emergency response planning guidelines
GNOME	General NOAA Oil Modeling Environment
H_2S	Hydrogen sulfide
HMTA	Hazardous Materials Transportation Act
HSWA	Hazardous and Solid Waste Amendments
HWCL	Hazardous Waste Control Law
IIRT	Initial Incident Response Team
IMP	Integrity Management Plans
km	kilometer
km^2	Square kilometer
kpa	kilopascal
kW	kilowatt
LCP	Lead containing paint
LFC	Las Flores Canyon
LFL	Lower flammability limit
LPG	Liquefied petroleum gas
m	meter
m^2	Square meters

m^3	Meters cubed
MAOP	Maximum Allowable Operating Pressure
MFL	Magnetic flux
MOU	Memorandum of Understanding
Mpa	Megapascal
NACE	National Association of Corrosion Engineers
NDT	Non-destructive testing
NESHAP	National Emissions Standards for Hazardous Air Pollutants
NGL	Natural gas liquids
NOAA	National Oceanic and Atmospheric Administration
NOV	Notice of Violation
OES	Office of Emergency Services
OSC	On-scene coordinator
OSCP	Oil Spill Contingency Plan
OSHA	Occupational Safety & Health Administration
OSPR	Office of Spill Prevention and Response
OSRA	Oil Spill Risk Analysis
P&D	Planning and Development
PAAPLP	Plains All American Pipeline, L.P.
ppm	Parts per million
psi	Pounds per square inch
Psig	Pounds per square inch guaged
PSM	Process Safety Management
QRA	Quantitative Risk Assessment
RCRA	Resource Conservation and Recovery Act
RMPP	Risk Management and Prevention Programs
ROV	Remotely Operated Vehicle
RSPA	Research and Special Programs Administration
SARA	Superfund Amendments and Reauthorization Act
SBCAPCD	Santa Barbara County Air Pollution Control District
SBCFD	Santa Barbara County Fire Department
SIMQAP	Safety Inspection, Maintenance and Quality Assurance Plan
SIRT	Sustained Incident Response Team
SPCC	Spill Prevention Countermeasures and Control
SSRRC	System Safety and Reliability Review Committee
SSRRC	System Safety and Reliability Review Committee
SSSV	Subsurface safety valve
SSV	Surface safety valve
TRMPP	Transportation Risk Management Prevention Program
USCG	U.S. Coast Guard
USFWS	U.S. Fish and Wildlife Service
USGS	U.S. Geological Survey
UT	Ultrasonic testing

PLATFORM HOLLY and Offshore Pipeline Failure Rate Calculations: Current Operations

Summary of Frequency Inputs

Platform Holly and Pipeline Summary	Current	Current
Scenario	Freq, per year	Years
Small Spills		
Holly - Blowouts any	8.56E-03	116.8
Holly - Wellhead Area Spill to Ocean - leak	2.21E-03	452.1
Holly - Separator Failure Spill to Ocean - leak	1.98E-03	504.7
Holly - Pumping and Shipping Spill to Ocean - leak	7.70E-02	13.0
Holly - Diesel Fuel Loading - Spill to Ocean	1.06E-01	9.4
Holly - misc material spills	3.50E-01	2.9
Pipeline - leaks	9.07E-02	11.0
Cumulative Small Spills	6.36E-01	1.6
Large Spills		
Holly - Blowouts catastrophic	3.44E-03	291
Holly - Wellhead area - rupture	6.28E-05	15,935
Holly - Separator Failure Spill to Ocean - rupture	6.57E-04	1,522
Holly - Pumping and Shipping Spill to Ocean - rupture	5.19E-04	1,927
Holly - External impact	1.00E-05	100,000
Pipeline - ruptures	2.39E-02	42
Cumulative Large Spills	2.86E-02	35
BOEM Approach - > 50 bbls pipeline	8.23E-03	122
BOEM Approach - < 50 bbls	4.77E-02	21
BOEM approach based on OCS Lease PEIR, 2012		

Detailed Calculations

PLATFORM HOLLY

Description	*Base rate*	*Units*	*Multiplier*	*Rate*	*Ref*
Holly - Blowouts any				**8.56E-03**	
Holly - Blowouts catastrophic				**3.44E-03**	
Number of wells			15		Venoco Application, over 15 years
Blowout during drilling: re-drills	4.84E-03	per well drilled	1.2	5.80E-03	MMS, 93% wellhead or drill floor, estimated redrills based one per year
Blowout during drilling: re-drills below, platform release	3.64E-04	per well drilled	1.2	4.37E-04	MMS, 7% subsea
Blowout during well workover	9.70E-05	per well	2.1	2.08E-04	HLID, 1992, gas well workovers, 93% wellhead or drill floor, workovers every 7 years per well
Blowout during well workover: below platform release	7.30E-06	per well	2.1	1.56E-05	HLID, 1992, gas well workovers, 7% subsea, assumes workovers every 7 years per well
Blowout during production	1.09E-04	per year	15	1.64E-03	HLID 1992, gas well production, 78% wellhead or drill floor, Assumes gas lift wells
Blowout during production: below platform release	3.08E-05	per year	15	4.62E-04	HLID 1992, gas well production, 22% subsea, Assumes gas lift wells
Oil spill conditional probability	3.30E-01	per demand	1	3.30E-01	Catastrophic well blowout, MMS
Holly - Wellhead Area Spill to Ocean - leak				**2.21E-03**	
Holly - Wellhead Area Spill to Ocean - rupture				**6.28E-05**	note: no drain system credit taken
Number of wellheads	24	number	1	2.40E+01	Current operation
Break of small fitting - after SSV	4.70E-04	per year	3	1.41E-03	HLID, 3 fittings per well
Pipe leak - after SSV	5.66E-05	/m.yr	10	5.66E-04	Rijnmond 1981, piping after wells heads to separators, per well
Pipe leak - after SSV - header	5.66E-05	/m.yr	25	1.42E-03	Rijnmond 1981, piping after headers to separators
Valve leak - after SSV	2.07E-04	/valve.yr	3	6.21E-04	HLID, Assume 90% are leaks, valves after SSV to separators, per well
Pipe rupture - after SSV	9.00E-07	/m.yr	10	9.00E-06	Rijnmond, Rupture of pipe, after SSV to separators, per well
Pipe rupture - after SSV - header	9.00E-07	/m.yr	25	2.25E-05	Rijnmond, Rupture of pipe, header to separators
Valve rupture - after SSV	2.30E-05	/valve.yr	3	6.90E-05	HLID, Assume 10% of leaks are rupture, after SSV to separators, per well
Pipe leak - before SSV	5.66E-05	/m.yr	10	5.66E-04	Rijnmond 1981, before SSV, per well
Valve leak - before SSV	2.07E-04	/valve.yr	6	1.24E-03	Rijnmond 1981 Assume 90% of leaks are significant, per well
Pipe rupture - before SSV	9.00E-07	/m.yr	10	9.00E-06	Rijnmond, Rupture of pipe, per well
Valve rupture - before SSV	2.30E-05	/valve.yr	6	1.38E-04	Rijnmond, Assume 10% of leaks are catastrophic rupture, per well
Pipe leak - under Platform	1.40E-04	/m.yr	65	9.10E-03	Rijnmond 1981, riser piping, no platform drain system protection, pipe length to ocean floor
Pipe rupture - under Platform	1.76E-06	/m.yr	65	1.14E-04	Rijnmond, Rupture of pipe, riser piping, no platform drain system protection, pipe length to ocean floor
Failure to close sub surface valve	1.00E-02	per year	1	1.00E-02	Lees, on demand failure to close, increased by 10 for sub surface service
Failure to close surface safety valve	1.00E-03	per year	1	1.00E-03	Lees, on demand failure to close
Failure of drainage system	6.40E-02	on demand	1	6.40E-02	

PLATFORM HOLLY and Offshore Pipeline Failure Rate Calculations: Current Operations

Description	*Base rate*	*Units*	*Multiplier*	*Rate*	*Ref*
Holly - Separator Failure Spill to Ocean - leak				**1.98E-03**	
Holly - Separator Failure Spill to Ocean - rupture				**6.57E-04**	
Vessel Rupture	3.00E-05	per year	2	6.00E-05	HLID, 10% rupture, 2 separators
Valve rupture	2.30E-05	/valve.yr	24	5.52E-04	2" valves and greater
Pipe rupture	9.00E-07	/m.yr	50	4.50E-05	estimated
Vessel leak	3.00E-04	per year	2	6.00E-04	
Break of small fitting	4.70E-04	per year	48	2.26E-02	estimated as twice the number of valves
Pipe leak	5.66E-05	/m.yr	50	2.83E-03	
Valve leak	2.07E-04	/valve.yr	24	4.97E-03	
Failure of drainage system	6.40E-02	on demand	1	6.40E-02	
Holly - Pumping and Shipping Spill to Ocean - leak				**7.70E-02**	
Holly - Pumping and Shipping Spill to Ocean - rupture				**5.19E-04**	
Vessel Rupture	3.00E-05	per year	2	6.00E-05	2 surge vessels
Valve rupture	2.30E-05	/valve.yr	18	4.14E-04	2" valves and greater
Pipe rupture	9.00E-07	/m.yr	50	4.50E-05	
Break of small fitting	4.70E-04	per year	36	1.69E-02	
Vessel leak	3.00E-04	per year	2	6.00E-04	
Pipe leak	5.66E-05	/m.yr	50	2.83E-03	
Valve leak	2.07E-04	/valve.yr	18	3.73E-03	
Pump leak or rupture	1.70E-02	per year	2	3.40E-02	HLID, 1992
Valve line-up error during pigging	0.01	probability per task	1	1.00E-02	Fail to reset valve: RM&IP
Incorrect reading of a gauge during pigging	4.50E-03	probability per task	1	4.50E-03	Rijnmond, 1981
Pigging operations per year	79	number	1	79	Based on APCD CVR reports of emulsion pigging events
Failure of drainage system	6.40E-02	on demand	1	6.40E-02	
Holly - Diesel Fuel Loading - Spill to Ocean				**1.06E-01**	
Hose failure	5.00E-03	per year	1	5.00E-03	CCPS, hose rupture
Loadings per year	2.40E+01	per year	1	2.40E+01	monthly, estimated, 1000 gal tank, 8000 gal used in 2014, 300 gal totes
Check valve failure	2.20E-03	per demand	1	2.20E-03	CCPS, 1989, Failure to check
Improper correction of linkage	4.40E-03	on demand	1	4.40E-03	Rijnmond, incorrect hose connection
Holly - External impact				**1.00E-05**	Pt. Ped Pt. Ped 1985 EIR, Figure 2-10
Holly - General human error small misc material spills	**3.50E-01**	**per year**	**1**	**3.50E-01**	Based on historical data of smaller spills, 7 smaller spills over 20 years
Holly - Failure of drainage system				**6.40E-02**	
High wind	4.20E-02	per demand	1	4.20E-02	Based on NOAA buoy 46053 > 20 mph
Valve fails opened/passes by	3.00E-04	per demand	3	9.00E-04	Rijnmond, leakage, 3 valves NC to water outfall
Tank T-4 or T-1 level alarm/switch failure	3.00E-04	per demand	1	3.00E-04	Lees, limit switches
Pump failure	1.86E-02		1	1.86E-02	CCPS, pump fails to start
PCV fails closed/blocked on pump discharge	2.20E-03		1	2.20E-03	CCPS, failure of control valve per demand
PIPELINE				**Freq/yr**	**Probability**
Emulsion Pipeline - Failure rates					
Pipeline Rupture				2.39E-02	61.6
Pipeline Leak				9.07E-02	97.3
Lifetime, years	40				
Average oil production, bpd	1750				
CSFM for this pipeline, leak	2.85E-02	per mile-year	3.03	8.62E-02	96.8
MMS pipeline throughput method, <50 bbl spill, per year				4.77E-02	85.2
CSFM for this pipeline, rupture	6.25E-03	per mile-year	3.03	1.89E-02	53.1
OPS all crude lines, spills > 50 bbl	8.90E-04	per mile-year	3.03	2.70E-03	10.2
MMS pipeline throughput method, >50 bbl spill, per year				8.23E-03	28.0
Pipeline Wave Impact on Beach					
Severe wave impact	5.00E-01	/yr	1	5.00E-01	Wave height greater than 4.5 meters. Frequency based on Bouy 107 Goleta Point 2002-2006. Freqeuncy of wave height occuring in any year
Operator failure to inspect	1.00E-01	/demand	1	1.00E-01	Failure to recognize incorrect status (RMIP).
Wave impact causes pipeline damage sufficient to rupture	1.00E-02	fraction	1	1.00E-02	Estimated. Once per 10 years potential damage has occurred and 10% to rupture.
Fraction of impacts to leak	9.00E-02	fraction	1	9.00E-02	Once per 10 years potential damage has occurred and 90% to leak.

PLATFORM HOLLY and Offshore Pipeline Failure Rate Calculations: Current Operations

SCADA - failure				**1.01E-01**	**Reference**
Phone line failure	2.28E-04	demand	1	2.28E-04	Estimated 8 hours per year down time
Pump shutdown failure	1.00E-04	on demand	1	1.00E-04	Rijnonmd, failure to stop on demand
Actuated valve failure	1.00E-03	on demand	1	1.00E-03	Lees, failure to operate on demand
Pressure Switch	1.00E-04	on demand	1	1.00E-04	Rijnonmd, failure on demand
Operator Restarts system, override SCADA	1.00E-01	on demand	1	1.00E-01	R&MIP, Fail to recognize incorrect status on inspection
Rates and Age Factors					
Piping Failure Rate: Rupture		4.50E-07	Average between WASH, Rijnmond, Lees and CCPS		
Piping Failure Rate: Leak		2.83E-05	Average between WASH, Rijnmond, Lees and CCPS		
Piping Failure Rate: Rupture - adverse environment		8.80E-07	High value between WASH, Rijnmond, Lees and CCPS.		
Piping Failure Rate: Leak - adverse environment		7.00E-05	High value between WASH, Rijnmond, Lees and CCPS		
PSV lifts light		4.25E-02	Average value of WASH, Rijnmond, Lees and CCPS		
PSV fraction of light lift that are wide open		0.1	Estimated based on general leak/rupture estimate of 10%.		
Rule 331 Inspection Frequency		4	times/yr	based on Venoco info	
PSV inspection frequency		1	times/yr	based on Venoco info	
Piping age factor		2.0		Based on SPLIC data,	
Vessel/Heat Exchanger age factor		2.0		Based on SPLIC data,	

PLATFORM HOLLY and Offshore Pipeline Failure Rate Calculations: Proposed Project Operations

Summary of Frequency Inputs

Platform Holly and Pipeline Summary	Current	Current	Proposed	Proposed
Scenario	Freq, per year	Years	Freq, per year	Years
Small Spills				
Holly - Blowouts any	8.56E-03	116.8	9.49E-03	105.3
Holly - Wellhead Area Spill to Ocean - leak	2.21E-03	452.1	2.21E-03	452.1
Holly - Separator Failure Spill to Ocean - leak	1.98E-03	504.7	1.98E-03	504.7
Holly - Pumping and Shipping Spill to Ocean - leak	7.70E-02	13.0	7.70E-02	13.0
Holly - Diesel Fuel Loading - Spill to Ocean	1.06E-01	9.4	1.27E-01	7.9
Holly - misc material spills	3.50E-01	2.9	2.73E-01	3.7
Pipeline - leaks	9.07E-02	11.0	9.07E-02	11.0
Cumulative Small Spills	6.36E-01	1.6	5.81E-01	1.7
Large Spills				
Holly - Blowouts catastrophic	3.44E-03	291	3.87E-03	258
Holly - Wellhead area - rupture	6.28E-05	15,935	6.28E-05	15,935
Holly - Separator Failure Spill to Ocean - rupture	6.57E-04	1,522	6.57E-04	1,522
Holly - Pumping and Shipping Spill to Ocean - rupture	5.19E-04	1,927	5.19E-04	1,927
Holly - External impact	1.00E-05	100,000	1.00E-05	100,000
Pipeline - ruptures	2.39E-02	42	2.39E-02	42
Cumulative Large Spills	2.86E-02	35	2.90E-02	34
BOEM Approach - > 50 bbls pipeline	8.23E-03	122	3.06E-02	
BOEM Approach - < 50 bbls	4.77E-02	21	1.77E-01	
BOEM approach based on OCS Lease PEIR, 2012				

Detailed Calculations

PLATFORM HOLLY

Description	*Base rate*	*Units*	*Multiplier*	*Rate*	*Ref*
Holly - Blowouts any				**9.49E-03**	
Holly - Blowouts catastrophic				**3.87E-03**	
Number of wells			21		Venoco Application, over 15 years, baseline one redrill per year plus 6 project wells
Blowout during drilling: re-drills	4.84E-03	per well drilled	1.2	5.80E-03	MMS, 93% wellhead or drill floor, estimated redrills based one per year
Blowout during drilling: re-drills below, platform release	3.64E-04	per well drilled	1.2	4.37E-04	MMS, 7% subsea
Blowout during well workover	9.70E-05	per well	3.0	2.91E-04	HLID, 1992, gas well workovers, 93% wellhead or drill floor, workovers every 7 years per well
Blowout during well workover: below platform release	7.30E-06	per well	3.0	2.19E-05	HLID, 1992, gas well workovers, 7% subsea, assumes workovers every 7 years per well
Blowout during production	1.09E-04	per year	21	2.29E-03	HLID 1992, gas well production, 78% wellhead or drill floor, Assumes gas lift wells
Blowout during production: below platform release	3.08E-05	per year	21	6.47E-04	HLID 1992, gas well production, 22% subsea, Assumes gas lift wells
Oil spill conditional probability	3.30E-01	per demand	1	3.30E-01	Catastrophic well blowout, MMS
Holly - Wellhead Area Spill to Ocean - leak				**2.21E-03**	
Holly - Wellhead Area Spill to Ocean - rupture				**6.28E-05**	note: no drain system credit taken
Number of wellheads	24	number	1	2.40E+01	Current operation
Break of small fitting - after SSV	4.70E-04	per year	3	1.41E-03	HLID, 3 fittings per well
Pipe leak - after SSV	5.66E-05	/m.yr	10	5.66E-04	Rijnmond 1981, piping after wells heads to separators, per well
Pipe leak - after SSV - header	5.66E-05	/m.yr	25	1.42E-03	Rijnmond 1981, piping after headers to separators
Valve leak - after SSV	2.07E-04	/valve.yr	3	6.21E-04	HLID, Assume 90% are leaks, valves after SSV to separators, per well
Pipe rupture - after SSV	9.00E-07	/m.yr	10	9.00E-06	Rijnmond, Rupture of pipe, after SSV to separators, per well
Pipe rupture - after SSV - header	9.00E-07	/m.yr	25	2.25E-05	Rijnmond, Rupture of pipe, header to separators
Valve rupture - after SSV	2.30E-05	/valve.yr	3	6.90E-05	HLID, Assume 10% of leaks are rupture, after SSV to separators, per well
Pipe leak - before SSV	5.66E-05	/m.yr	10	5.66E-04	Rijnmond 1981, before SSV, per well
Valve leak - before SSV	2.07E-04	/valve.yr	6	1.24E-03	Rijnmond 1981 Assume 90% of leaks are significant, per well
Pipe rupture - before SSV	9.00E-07	/m.yr	10	9.00E-06	Rijnmond, Rupture of pipe, per well
Valve rupture - before SSV	2.30E-05	/valve.yr	6	1.38E-04	Rijnmond, Assume 10% of leaks are catastrophic rupture, per well
Pipe leak - under Platform	1.40E-04	/m.yr	65	9.10E-03	Rijnmond 1981, riser piping, no platform drain system protection, pipe length to ocean floor
Pipe rupture - under Platform	1.76E-06	/m.yr	65	1.14E-04	Rijnmond, Rupture of pipe, riser piping, no platform drain system protection, pipe length to ocean floor
Failure to close sub surface valve	1.00E-02	per year	1	1.00E-02	Lees, on demand failure to close, increased by 10 for sub surface service
Failure to close surface safety valve	1.00E-03	per year	1	1.00E-03	Lees, on demand failure to close
Failure of drainage system	6.40E-02	on demand	1	6.40E-02	

PLATFORM HOLLY and Offshore Pipeline Failure Rate Calculations: Proposed Project Operations

Description	*Base rate*	*Units*	*Multiplier*	*Rate*	*Ref*
Holly - Separator Failure Spill to Ocean - leak				**1.98E-03**	
Holly - Separator Failure Spill to Ocean - rupture				**6.57E-04**	
Vessel Rupture	3.00E-05	per year	2	6.00E-05	HLID, 10% rupture, 2 separators
Valve rupture	2.30E-05	/valve.yr	24	5.52E-04	2" valves and greater
Pipe rupture	9.00E-07	/m.yr	50	4.50E-05	estimated
Vessel leak	3.00E-04	per year	2	6.00E-04	
Break of small fitting	4.70E-04	per year	48	2.26E-02	estimated as twice the number of valves
Pipe leak	5.66E-05	/m.yr	50	2.83E-03	
Valve leak	2.07E-04	/valve.yr	24	4.97E-03	
Failure of drainage system	6.40E-02	on demand	1	6.40E-02	
Holly - Pumping and Shipping Spill to Ocean - leak				**7.70E-02**	
Holly - Pumping and Shipping Spill to Ocean - rupture				**5.19E-04**	
Vessel Rupture	3.00E-05	per year	2	6.00E-05	2 surge vessels
Valve rupture	2.30E-05	/valve.yr	18	4.14E-04	2" valves and greater
Pipe rupture	9.00E-07	/m.yr	50	4.50E-05	
Break of small fitting	4.70E-04	per year	36	1.69E-02	
Vessel leak	3.00E-04	per year	2	6.00E-04	
Pipe leak	5.66E-05	/m.yr	50	2.83E-03	
Valve leak	2.07E-04	/valve.yr	18	3.73E-03	
Pump leak or rupture	1.70E-02	per year	2	3.40E-02	HLID, 1992
Valve line-up error during pigging	0.01	probability per task	1	1.00E-02	Fail to reset valve: RM&IP
Incorrect reading of a gauge during pigging	4.50E-03	probability per task	1	4.50E-03	Rijnmond, 1981
Pigging operations per year	79	number	1	79	Based on APCD CVR reports of emulsion pigging events
Failure of drainage system	6.40E-02	on demand	1	6.40E-02	
Holly - Diesel Fuel Loading - Spill to Ocean				**1.27E-01**	
Hose failure	5.00E-03	per year	1	5.00E-03	CCPS, hose rupture
Loadings per year	2.88E+01	per year	1	2.88E+01	biweekly, baseline plus increased use from drilling project wells
Check valve failure	2.20E-03	per demand	1	2.20E-03	CCPS, 1989, Failure to check
Improper correction of linkage	4.40E-03	on demand	1	4.40E-03	Rijnmond, incorrect hose connection
Holly - External impact				**1.00E-05**	Pt. Ped Pt. Ped 1985 EIR, Figure 2-10
Holly - General human error small misc material spills	**2.73E-01**	**per year**	**1**	**2.73E-01**	Based on historical data of smaller spills, 3 smaller spills over 11 years
Holly - Failure of drainage system				**6.40E-02**	
High wind	4.20E-02	per demand	1	4.20E-02	Based on NOAA buoy 46053 > 20 mph
Valve fails opened/passes by	3.00E-04	per demand	3	9.00E-04	Rijnmond, leakage, 3 valves NC to water outfall
Tank T-4 or T-1 level alarm/switch failure	3.00E-04	per demand	1	3.00E-04	Lees, limit switches
Pump failure	1.86E-02		1	1.86E-02	CCPS, pump fails to start
PCV fails closed/blocked on pump discharge	2.20E-03		1	2.20E-03	CCPS, failure of control valve per demand
PIPELINE				**Freq/yr**	**Probability**
Emulsion Pipeline - Failure rates					
Pipeline Rupture				2.39E-02	61.6
Pipeline Leak				9.07E-02	97.3
Lifetime, years	40				
Average oil production, bpd	6500				
CSFM for this pipeline, leak	2.85E-02	per mile-year	3.03	8.62E-02	96.8
MMS pipeline throughput method, <50 bbl spill, per year				7.88E-02	95.7
CSFM for this pipeline, rupture	6.25E-03	per mile-year	3.03	1.89E-02	53.1
OPS all crude lines, spills > 50 bbl	8.90E-04	per mile-year	3.03	2.70E-03	10.2
MMS pipeline throughput method, >50 bbl spill, per year				1.38E-02	42.3
Pipeline Wave Impact on Beach					
Severe wave impact	5.00E-01	/yr	1	5.00E-01	Wave height greater than 4.5 meters. Frequency based on Bouy 107 Goleta Point 2002-2006.
Operator failure to inspect	1.00E-01	/demand	1	1.00E-01	Failure to recognize incorrect status (RMIP).
Wave impact causes pipeline damage sufficient to rupture	1.00E-02	fraction	1	1.00E-02	Estimated. Once per 10 years potential damage has occurred and 10% to rupture.
Fraction of impacts to leak	9.00E-02	fraction	1	9.00E-02	Once per 10 years potential damage has occurred and 90% to leak.

PLATFORM HOLLY and Offshore Pipeline Failure Rate Calculations: Proposed Project Operations

SCADA - failure				**1.01E-01**	**Reference**
Phone line failure	2.28E-04	demand	1	2.28E-04	Estimated 8 hours per year down time
Pump shutdown failure	1.00E-04	on demand	1	1.00E-04	Rijnonmd, failure to stop on demand
Actuated valve failure	1.00E-03	on demand	1	1.00E-03	Lees, failure to operate on demand
Pressure Switch	1.00E-04	on demand	1	1.00E-04	Rijnonmd, failure on demand
Operator Restarts system, override SCADA	1.00E-01	on demand	1	1.00E-01	R&MIP, Fail to recognize incorrect status on inspection
Rates and Age Factors					
Piping Failure Rate: Rupture		4.50E-07	Average between WASH, Rijnmond, Lees and CCPS		
Piping Failure Rate: Leak		2.83E-05	Average between WASH, Rijnmond, Lees and CCPS		
Piping Failure Rate: Rupture - adverse environment		8.80E-07	High value between WASH, Rijnmond, Lees and CCPS.		
Piping Failure Rate: Leak - adverse environment		7.00E-05	High value between WASH, Rijnmond, Lees and CCPS		
PSV lifts light		4.25E-02	Average value of WASH, Rijnmond, Lees and CCPS		
PSV fraction of light lift that are wide open		0.1	Estimated based on general leak/rupture estimate of 10%.		
Rule 331 Inspection Frequency		4	times/yr	based on Venoco info	
PSV inspection frequency		1	times/yr	based on Venoco info	
Piping age factor		2.0		Based on SPLIC data,	
Vessel/Heat Exchanger age factor		2.0		Based on SPLIC data,	

Spill Volumes

From SPCC, 2015 (as per Applicant submissions)
substancial harm critieria listing

Spill Scenario	Total Fluids Spill Volume, bbls	Fraction Water	Oil Spill Volume, bbls	Total Fluids Spill Volume, m3	Crude Oil Spill Volume, m3	Total Fluids Spill Volume, bbls (m3)	Crude Oil Spill Volume, bbls (m3)
Test separators (4)	41.9	0.8	8	7	1	42 (6.7)	8 (1.3)
Group separators (2)	220	0.8	44	35	7	220 (35)	44 (7)
Surge vessels (2)	200	0.33	134	32	21	200 (31.8)	134 (21.3)
Lube oil drain tank	3.6	0	4	1	1	4 (0.6)	4 (0.6)
Diesel fuel tank	35.7	0	36	6	6	36 (5.7)	36 (5.7)
Diesel tote tanks	80	0	80	13	13	80 (12.7)	80 (12.7)
Lube oil tote tanks	11.9	0	12	2	2	12 (1.9)	12 (1.9)
Switchgear Bldg	2.9	0	3	0	0	3 (0.5)	3 (0.5)
Transformers combined	76.9	0	77	12	12	77 (12.2)	77 (12.2)
55 gallon drums	32.7	0	33	5	5	33 (5.2)	33 (5.2)
Misc	12.9	0	13	2	2	13 (2.1)	13 (2.1)
Total + Pipeline Modeled	883	-	553	140	88	883 (140)	553 (87.9)
Total Holly Vessels/tanks	719	-	443	114	70	719 (114)	443 (70.4)
Emulsion Pipeline, modeled	164	0.33	110	26	17	164 (26)	110 (17.5)
Emulsion Pipeline, worst case	601	0.33	403	96	64	601 (95.5)	403 (64)
Total Worst Case	1319	-	845	210	134	1319 (209.8)	845 (134.4)

Fraction water based on 2014 operations as per DOGGR database. Pipeline/surge vessels based on Applicant data

From OSCP, 2015 (as per Applicant submissions)
Reasonable Worst Case Discharge

Location	Total Fluids Spill Volume, bbls	Total Fluids Spill Volume, bbls (m3)
EOF	3000	3000 (477)
Ellwood Pier	11.9	12 (2)
Holly: tanks/vessels	716	716 (114)
Holly: flowlines	72	72 (11)
Holly: blowout-gas lift blowdown	250	250 (40)
Holly: blowout-free flowing production well	30000	30000 (4770)
Holly: total	30811	30,811 (4899)
Holly: Only Holly	30788	30,788 (4895)
Holly: pipeline - modeled	23	23 (4)

Pipeline release volume based on modeled release. OSCP page Q-10

PHMSA Pipeline Worst Case Discharge (as per Applicant submissions)

Item	Value
Time to discovery, min	1.25
Time to shutdown, min	0.75
Pumpin rate, bph	271
Pipeline volume, bbls	162.5
Worst Case discharge, bbls (m3)	172(35)

Note: as per OSCP page Q-10, pipeline shutdown time is 2 minutes
not 1.5 min as indicated in the OSCP page R-8

Offshore Pipeline Spill Volumes
Modeled Pipeline Release using POSVCM

Inputs	Value	Value (m3)
Temperature, F	130	
Roughness, ft	0.00015	
Heat transfer coef, btu/ft2/hr/F	10	
Pipe Size, inches	6	
Oil density, lb/gal	7.67	
Water cut, %	33	
Riser length, ft	230	
Pipeline length to shorefall, ft	16010	
Onshore pipeline to EOF, ft	940	
Pig catcher elev, ft	23	
Holly pig launcher elev, ft	23	
Current production rate, bopd	3400	
Proposed Project production rate, bopd	13000	
Pumping rate, bpd, total fluids - Baseline	5075	
Pumping rate, bpd, total fluids - PP	16250	
Worst case shutdown time, min	60	
Results		
Current, bbls, 60 minute, total fluids	232	232 (37)
Proposed Project, bbls, 60 minute, total fluids	710	710 (113)
Percent increase	206%	

Offshore Pipeline Spill Volumes
Maximum Possible Spill Volume

Inputs	Value	Value (m3)
Pipeline Volume, bbls	601	
Pumping rate, bpd, total fluids - Baseline	5075	
Pumping rate, bpd, total fluids - PP	16250	
Pumping duration, after leak, minutes	60	
Total Maximum Release Size - Baseline, bbls	812	812 (129)
Total Maximum Release Size - PP, bbls	1278	1,278 (203)
Baseline pipeline water cut of 33% based on 2014 operations after Holly separation	*0.33*	
Project pipeline water cut of 25% based on Applicant and 13,000 bopd		

Worst Case (Pipeline models + Holly Inventory)-Baseline	31020	31,020 (4932)
Worst Case (Pipeline inventory+pumping+Holly Inventory)-Baseline	31600	31,600 (5024)
Worst Case (Pipeline models + Holly Inventory)-PP	31498	31,498 (5008)
Worst Case (Pipeline inventory+pumping+Holly Inventory)-PP	32066	32,066 (5098)

GNOME Model - Beached Volumes

Existing Operations

Flow Regime	Wind Direction from	Fraction Beached (from GNOME Runs)	Worst Case Beached Volume, bbl (m^3)	Pipeline Spill Beached Volume, bbl (m^3)	Location Impacted
Relaxation	North	0.000	0(0)	0(0)	Coast to west
	East	0.085	2675(425)	20(3)	Coast to west
	South	0.993	31390(4991)	230(37)	Coast to west
	West	0.473	14959(2379)	110(17)	Coast
Convergent	North	0.004	134(21)	1(0)	San Miguel Island
	East	0.008	248(39)	2(0)	Coast to west
	South	0.808	25544(4061)	188(30)	Coast to west
	West	0.015	478(76)	4(1)	Coast
Upwelling	North	0.001	19(3)	0(0)	Coast
	East	0.027	841(134)	6(1)	Coast
	South	0.967	30549(4857)	224(36)	Coast
	West	0.498	15724(2500)	115(18)	Coast to east

Worst case size spill	31,600	bbl
Pipeline size spill	232	bbl

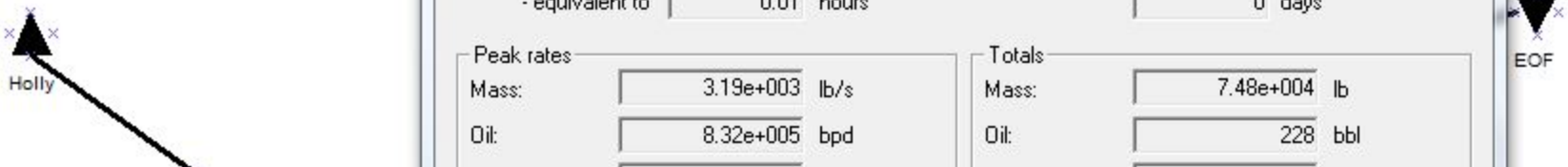
Proposed Project Operations

Flow Regime	Wind Direction from	Fraction Beached (from GNOME Runs)	Worst Case Beached Volume, bbl (m^3)	Pipeline Spill Beached Volume, bbl (m^3)	Location Impacted
Relaxation	North	0.000	0(0)	0(0)	Coast to west
	East	0.085	2714(432)	60(10)	Coast to west
	South	0.993	31,853(5065)	705(112)	Coast to west
	West	0.473	15,180(2414)	336(53)	Coast
Convergent	North	0.004	136(22)	3(0)	San Miguel Island
	East	0.008	252(40)	6(1)	Coast to west
	South	0.808	25,920(4121)	574(91)	Coast to west
	West	0.015	485(77)	11(2)	Coast
Upwelling	North	0.001	19(3)	0(0)	Coast
	East	0.027	853(136)	19(3)	Coast
	South	0.967	31,000(4929)	686(109)	Coast
	West	0.498	15,955(2537)	353(56)	Coast to east

Worst case size spill	32,066	bbl
Pipeline size spill	710	bbl

MMS Pipeline Oil Spill Volume Computer Model - [Offshore pipeline baseline2.wcd]

File Edit View Object Scenario Result Window Help



Discharge Summary

Time to get total mass:	0.383333	min
- equivalent to	0.01	hours
	0	days

Peak rates

Mass:	3.19e+003	lb/s
Oil:	8.32e+005	bpd
Gas:	0	mmcfd
Oil (std.cond):	8.55e+005	stbd
Gas (std.cond):	0	mmscfd

Totals

Mass:	7.48e+004	lb
Oil:	228	bbl
Gas:	0	ft3
Oil (std.cond):	232	stb
Gas (std.cond):	0	scf

Warnings

Simple calculation method used for 0 GOR fluids. Time estimated is based on peak release rate

Close

MMS Pipeline Oil Spill Volume Computer Model - Offshore pipeline PP2.wcd

File Edit View Object Scenario Result Window Help

Offshore pipeline PP2.wcd

Holly

riser

seafl

EOF

Discharge Summary

Time to get total mass:	1.08333	min			
- equivalent to	0.02	hours		0.001	days

Peak rates

Mass:	3.54e+003	lb/s
Oil:	9.31e+005	bpd
Gas:	0	mmcfd
Oil (std.cond):	9.49e+005	stbd
Gas (std.cond):	0	mmscfd

Totals

Mass:	2.29e+005	lb
Oil:	706	bbl
Gas:	0	ft3
Oil (std.cond):	710	stb
Gas (std.cond):	0	scf

Warnings

Simple calculation method used for 0 GOR fluids. Time estimated is based on peak release rate

Close