4.8 Safety, Risk of Upset, and Hazards

This section discusses the potential safety, risk of upset and hazardous materials impacts that could result from the Proposed Project.

The information in this section describes the environmental setting (including baseline risks), regulatory setting, and states the significance criteria, Proposed Project potential levels of risk to the public or the environment associated with the facility and pipeline construction and operations, and the significance of the risks. Mitigation measures are also identified which would reduce the risk levels.

The safety and risk of upset analysis addresses upset scenarios that could immediately and adversely affect public safety, such as explosions, fires and releases of flammable or toxic gas. The analysis assesses what upsets could occur, based on the Proposed Project facility design and operations, estimates the frequency of the upsets and assesses what the resulting consequences of the upsets could be. These are then compared to the significance thresholds to determine the level of significance.

This section also analyzes the baseline and the Proposed Project for the impacts of oil spills, including the estimated frequency and volume of spills. This section does not assess the impacts of spills to water quality or biological resources. The Biological Resources section and the Hydrology and Water Quality sections discuss those oil spill impacts.

This section also includes an assessment of potential impacts related to soil contamination and proposed remediation activities to address contamination. Air emissions from soil contamination are discussed in Section 4.2, Air Quality and Greenhouse Gases.

Safety impacts related to worker safety and OSHA-related requirements are not addressed in this EIR as this EIR addresses only potential impacts to humans not associated with the Proposed Project (contractors or the employees of E&B) as per CEQA.

For a discussion of odor impacts and health risk impacts, cancer, chronic and less immediate acute impacts see Section 4.2, Air Quality.

Detailed risk calculation spreadsheets are included in the Appendix C.

In general, oil production fields and oil and gas facilities present potential hazards to employees and the public, depending on the type of facility, due to the presence of flammable gas, toxic gas, and gas processing by-products, such as flammable propane and butanes. Drilling operations present hazards, depending on reservoir characteristics, because placing a well-bore through potentially pressurized reservoirs could create blow-out situations and release flammable gases. Storing and transporting natural gas, propane, butane, and other gas liquids can also create a hazard.

In addition, storing and transporting crude oil presents hazards due to crude oil tank fires and environmental hazards due to crude oil spills. This section discusses these hazards, their

associated estimated frequency of occurrence based on industry-wide experience, and their potential impacts and resulting risks.

The Proposed Oil Project, the Pipeline and the Proposed City Maintenance Yard Project would each have the potential for impacts on Safety and Risk. As the Proposed Oil Project and the Pipelines would operate together during the operational phases, these have been discussed in the same sub-section. The Proposed City Maintenance Yard Project has been discussed in a separate impacts sub-section.

4.8.1 Environmental Setting

For the Proposed Project, the environmental setting or baseline conditions reflect the risks of upset, spills or site contamination associated with existing facilities. The Project is proposed in an area that does not currently have any oil and gas operations. However, the current maintenance yard operation does present some acceptable risk to the public or the environment, including the risk of small spills of oil, accidents related to releases from vehicle gasoline tanks (both of which would not produce offsite impacts and therefore produce acceptable risk levels) or releases from the onsite propane tank. There is also some existing site contamination (see section 4.8.1.4).

4.8.1.1 Study Area and Scope

The study area is defined as any area that could be impacted by a release of hazardous materials, generally the area within 1,000 feet of the Proposed Project Site or pipeline route. This distance includes all areas that could be immediately impacted by a release of hazardous materials. The study area includes the Proposed Project Site and any routes associated with proposed pipelines. Spills could also flow down storm drains and affect areas farther from the release location depending on drainage patterns.

An upset condition from the Proposed Project operations that subsequently releases hazardous materials could adversely impact public health and safety or environmental resources in the study area. Potentially affected areas include:

- Residences and businesses along 6th Street, 7th Street, 8th Street, Cypress Avenue, Loma Drive, and residences on the east side of the Greenbelt along Ardmore Avenue, 5th Street, 6th Street , 7th Street and 8th Street. Depending on the specific scenario, some additional areas might be impacted;
- Recreational users along the Greenbelt adjacent to the Project Site;
- Recreational users within the South Park;
- Areas adjacent to the crude oil pipeline routes along Valley Drive and Herondo Street and 190th Street;
- Ocean areas around the Herondo Street outfall;
- Areas adjacent to the natural gas pipeline route along Valley Drive;

- Areas adjacent to the crude oil pipeline; and
- Pedestrian traffic along Valley Drive and area streets immediately adjacent to the Project Site.

4.8.1.2 Risk Assessment Methodology

The method for evaluating risks used in this EIR is a Quantitative Risk Assessment (QRA). An explanation of a Quantitative Risk Assessment (QRA) is included in this section. In addition, spill risks and security risks are also discussed.

Facility Quantitative Risk Assessment Approach

The QRA analyzes the risks presented by industrial operations on nearby populations. The assessment follows commonly accepted industry standards including the recommendations of the Center for Chemical Process Safety (CCPS), the Health and Safety Executive of the United Kingdom, and the County of Santa Barbara Environmental Threshold and Guidelines for Public Safety. The QRA examines the risks of immediate human safety impacts.

The main objective of the QRA is to assess the facility's risk of generating serious injuries or fatalities to members of the public, and to develop mitigation measures that could reduce these risks. The development of the serious injury and fatality aspects of the QRA involves five major tasks:

- Identifying release scenarios;
- Developing frequencies of occurrence for each release scenario;
- Determining consequences of each release scenario;
- Developing estimates of risk, including risk profiles; and
- Developing risk-reducing mitigation measures.

Figure 4.8-1 shows the steps in developing a QRA.

A QRA computer model, developed by Marine Research Specialists, was used to calculate the risk profiles (or FN curves) and, in conjunction with Geographic Information System software, to manage the data in accordance with CCPS guidelines for hazard assessments (CCPS 1989). The model is based on a polar coordinate grid of cells. The grid extends at least 0.5 miles from the facility in all directions and has varying cell sizes depending on the populations and ignition sources. Hazard zones were then laid over the grid to determine populations impacted. The following sections discuss the information developed as inputs to the model.

Meteorological conditions at the site are represented by two stability classes: F stability and D stability. Wind stability is divided into stability classes from A to F, with F being the most stable. Wind conditions are divided into 16 directions and the probability of wind in each direction, at each stability class and speed, is entered. The meteorological conditions are based on wind data taken from the King Harbor meteorological station.

Fatality and serious injury probabilities are entered for each type of scenario (i.e., flame jets, fires, vapor clouds, including flammable and toxic clouds, explosions, and boiling liquid

expanding vapor explosions), indicating the percentage of persons who are exposed to a scenario that would suffer serious injuries or fatalities.

Population density information developed for each receptor includes the number of persons present at each location, the area over which the persons are distributed, and the maximum number of persons that could be exposed. If a cloud covers only a portion of the area, the population density is used to determine the number of persons exposed. Census data is used for residential areas based on the block group populations and areas.

A use factor is applied to each receptor based on the hours per day that persons are at the location. For example, a receptor that has persons at it 12 hours per day would have a use factor of 0.5. This factor reduces the frequency of a release scenario impacting persons.

An ignition probability at each receptor is applied, which defines the probability that a flammable cloud would reach the receptor and ignite and affect the receptor location. For example, if there are no ignition sources between the receptor and the release point and there is an ignition point at the receptor, such as a campfire, which has a high probability of igniting the cloud, then the ignition probability would be 1.0 at the receptor.

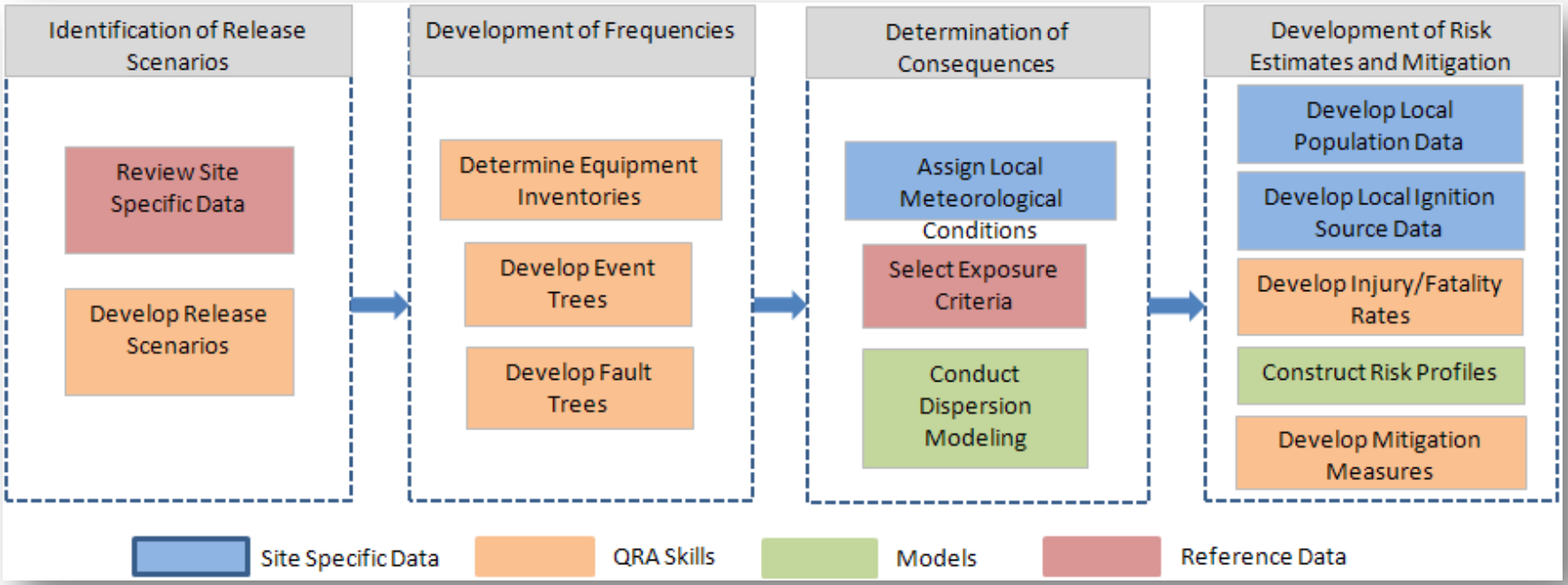
This would mean that any receptor farther from the release point would not be impacted by a flammable gas release. If there are ignition sources at the release location (such as flares or heaters), the ignition probability at the receptors would be less than 1.0, meaning that, part of the time, the flammable cloud would not reach the receptors at all. The sum of ignition probabilities along any one path is equal to or less than 1.0.

A shielding factor is also applied to receptor locations. The shield factor is applicable to thermal scenarios only, such as flame jets, fires, or boiling liquid expanding vapor explosions. Thermal scenarios only produce impacts if the receptor is directly exposed to the flame and has a “line of sight.” Buildings, vegetation, terrain, and other types of obstructions would prevent persons exposed to the fire from experiencing the full effects, and would reduce the probability that the person would suffer a serious injury or fatality.

Release scenario frequencies are determined though failure rate analysis and fault trees, which detail the general conditions and equipment-specific frequencies that could lead to a release. Event trees evaluate post-release behavior of the released material, such as whether it forms a flammable cloud, flame jet, toxic cloud, explosion, or a boiling liquid expanding vapor explosion.

The end products for the serious injury and fatality analysis are “risk profile” or FN (frequency/number) curves, one for fatalities and one for serious injuries, developed from the scenario frequencies and effected populations for each scenario. The risk profile curves estimate the risk that any existing population would suffer fatalities or serious injuries. An FN curve is a logarithmic plot of the number of serious injuries/fatalities plotted against the frequency of the scenario that produces the serious injuries/fatalities. The lower left corner of the plot is the lowest risk area (few injuries/fatalities at a low frequency) and the upper right corner of the plot (many injuries/fatalities at a high frequency) is the highest risk area.

Figure 4.8-1 Steps Involved in Developing a Quantitative Risk Assessment



In general, a conservative (estimating more risk than would actually occur) approach is taken in conducting the analysis. Using a conservative approach ensures that risks are conservative and ensures the focus of efforts are on the areas that produce the highest risk. Conservative assumptions include the following:

- Minimal piping friction effects. For flammable gas releases, consequence analysis assumed that release volumes were located near the break source and all releases were assumed to behave like a release from a short pipe length or a hole in a vessel. Long piping lengths, which would increase the friction and reduce the release rates, were not included. For example, if a scenario includes two exchangers, nine vessels, two filters, and an estimated 240 meters of piping, it was assumed that this entire inventory was released as though it was contained within a single vessel at the unit temperature and pressure and released through a short pipe segment. In reality, the gas might have to travel through piping and equipment to get to the release point, or could only travel a short distance if the release occurred near the largest inventory location. This variability in the release location and the resulting release characteristics necessitates using a worst case release location. Greater piping lengths would reduce the release rate and the subsequent impact zone. In addition, for flammable releases, the peak release rate was used to determine the hazard zone. This approach produces larger hazard zones since the release rate would decrease over time, thereby reducing the size of the impact zone over time.
- Minimum human intervention and shutdown systems were included. It was assumed there would be no human intervention in the event of a crisis situation. Manual shutdown systems were assumed not to be activated or activated only after a sufficient amount of material was released, which would allow the hazard zones to reach their maximum extents (given the dispersion and meteorological conditions at the time of the release). All automatic shutdown systems that can isolate portions of the plant were assumed to fail and produce the largest release volume. However, the failure rates of these automatic shutdown systems were included in the fault tree analysis. It was assumed that compressor low pressure shutdown systems would prevent the system from continuing to operate and compressing additional gas from the wells, or allowing flow back from the downstream higher-pressure portion, in the event of an equipment failure.
- Maximum release volumes were assumed producing the worst case consequences. All releases were assumed to release the entire volume of the equipment. In reality, depending on the release location, there could be numerous valves and bottlenecks, that could prevent a release of the majority of the gas inventory in the field through a given pipe or equipment rupture.

Release Scenarios

The approach to developing release scenarios is to group the equipment and operations by operating parameters - equipment with similar temperatures, pressure, and composition are grouped into a single set of scenarios. This generally produces a set of release scenarios for each process. Each set of release scenarios contains at least one rupture release and one leak release. A rupture is defined as a large release over a short period of time caused, for example, by catastrophic equipment failure. Ruptures are generally associated with releases through holes larger than 1 inch. A leak is defined as a release due to a small valve failure or a small hole in a

vessel, for example, generally less than 1 inch in diameter. This approach encompasses a range of risks by including a less frequent, more severe scenario, and a more frequent, less severe scenario. In some cases, the leak release actually produces a higher risk (i.e., combination of consequence and frequency) than the associated rupture release because leaks occur more frequently than ruptures.

The principal immediate hazards to public health at an oil facility or oil field (areas with drilling and production and processing) include:

- Releases of flammable gas causing vapor cloud explosions or thermal impacts from fire and flame jets;
- Releases of propane (gasses stored as a liquid under pressure) causing vapor cloud explosions, thermal impacts from fire and flame jets, or thermal and overpressure impacts from explosions and boiling liquid expanding vapor explosions;
- Releases of gas containing toxic materials (such as hydrogen sulfide) or release of odorant causing toxic impacts; and
- Releases of crude oil with subsequent fire causing impacts from thermal exposure to crude oil fires.

Failure Frequencies

Once the scenarios have been identified, the QRA analysis estimates the frequency of each scenario. This is done by combining the series of events necessary for the scenario to be realized. These are called “fault trees.” For example, a release from a simple pipe and valve system could be due to the pipe breaking or leaking, the valve breaking or leaking, or an operator leaving a valve open during a maintenance procedure. Any of these events would cause a release of the material. Failure rate databases quantify how often each of these events has occurred industry-wide historically.

Several failure rate databases are available that list failure rates for a long list of equipment types and operations. These databases are produced from a large dataset of industry-wide information from hundreds of facilities. Some rates are industry-specific, such as nuclear facilities, liquefied petroleum gas facilities, or oil and gas industries, whereas some are more general. The sources included the Center for Chemical Process Safety, Lees, WASH 1400, Hydrocarbon Leak and Ignition database, and the Rijnmond Public Authority reports, which include both equipment failures and failures due to human error. These industry-wide failure rate databases incorporate a range of equipment, differing in design standards and equipment age. Therefore, the failure rates are considered an average of a group of equipment that might include some older equipment and some relatively new equipment.

Failure rates are developed, for example, from a listing of valve breaks that have occurred in an industry. Dividing the number of breaks per year by an estimate of the number of valves in that industry generates a failure rate. For example, this rate may be 0.003 leaks per year per valve, so that if there are 100 valves at a facility, 0.3 leaks per year or approximately one leak every 3 years could be expected. The same information is available per meter of pipe length as a function of pipe size, for example. Other examples of this type of information include the number of times per year a pump might be expected to fail or a pump seal would develop a leak.

Rates can also be based on what is called a demand basis, which is a probability that if the equipment is called upon, it will not work. Good examples of this are the probability that a switch will not operate if it is used, or that a fire pump will not operate if it is needed.

Failure rate databases also include human error rates. These include the frequency that a valve is not closed correctly, or that a series of instructions are not followed correctly, or that a hose is not connected properly. These human error rates are based upon industry-wide data and have been incorporated into the fault trees where applicable.

Table 4.8-1 shows frequencies for some common events in everyday life taken from the databases. Appendix D includes the source and frequency calculations.

Table 4.8-1 Frequencies for Common Events

Event	Number	Interval
Failure to follow instructions occurs once every	18	times it is done
Simple arithmetic error with self checking occurs once every	40	times it is done
Incorrect reading of a gauge occurs once every	222	times it is read
Fail to read a 10 digit number correctly occurs once every	167	times it is read
A switch fails to operate once every	3,333	times it is used
A welded connection leaks once every	1,142	years per weld
A computer fails to run once every	10.5	months
A propane tank explodes once every	10,000,000	years per tank

Sources: CCPS 1989b, R&MIP 1988

The failure rate databases that were used to estimate the base failure frequencies include a range of equipment types, services, and age. Many of the failure rates, for example, are based on services that are much more hazardous than oil and gas processing, such as boiler systems, piping, and refinery reactor equipment.

Industry data on the correlation between equipment age and failure rates is sparse; in fact, several studies indicate that there is no correlation. In one study, 50 percent of failures were attributable to pressure vessels that were less than 10 years old and 50 percent were attributed to vessels more than 10 years old (Lees 1996). This is primarily because failures occur during the first few years of equipment life due to manufacturing inadequacies. An examination of facilities regulated by the Bureau of Ocean Energy Management, Regulation, and Enforcement (BOEM) (formerly the Minerals Management Service) in the Gulf of Mexico over the past 10 years shows that equipment failure rates actually decrease even as the average equipment age increases.

However, other studies indicate an increase in failure rates with age. Thomas developed a quantitative method for determining the failure rates in process piping and vessels using empirical data from the process industry (Thomas 1981). That method involves examining the piping and vessel size, construction geometry, and number and length of welds, as well as the equipment age and maintenance practices. This method assigns an age factor as high 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. This method estimated that 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 remainder.

Since the Thomas report, a number of refinements and data development activities have occurred, mostly focused on the nuclear industry. The worldwide nuclear industry has developed "risk informed in-service inspection" techniques. A number of approaches to risk informed in-service inspection have been proposed, but most of them rely on assessing the severity of process degradation mechanics and assigning a level of risk to specific processes. Developed databases, namely the SKI-PIPE for the worldwide nuclear industry, allow for a comparison to the Thomas model and databases. A study examining the SKI-PIPE database 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 (Lydel 2000).

The California State Fire Marshal (CSFM) pipeline study indicates that pipeline leak rates are relatively constant during the 30- to 40-year timeframe, and then increase substantially (CSFM 1993). The failure rates of the oldest pipelines are 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 more than 40 years, lack of proper maintenance would substantially increase failure rates. However, if proper maintenance practices are employed and equipment is repaired or replaced proactively, it would be assumed that base failure rates would be similar to the average rates seen in the industry. Since all age-related degradation issues (e.g., corrosion) cannot be captured by even the best maintenance programs, a factor of 2.0 has been included in the base failure rates for equipment more than 20 years old. Since all equipment would be new for the Project, this factor would not be relevant until the later years of the Project.

The average base failure rate for a group of equipment was quantified by examining the range of failure rates between the different databases (WASH, Lees, HLID, Rijnmond, and Center for Chemical Process Safety) and assigning the higher failure rates to equipment in corrosive service and receiving less maintenance. For example, the failure rates for a rupture of process piping, from a number of reputable studies, range from a very high rate of once every 40,000 meter-years (the interval between failures for a single meter of pipe) to a very low rate of once every 11 million meter-years (WASH1400, Lees, Center for Chemical Process Safety, and Rijnmond). 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 below-standard maintenance. The lowest rates are assumed to correlate to facilities that have less- or non-corrosive service and the highest standards of maintenance. The Proposed Project facilities were assumed to be new with less- or non-corrosive service because they are associated with relatively sweet gas (<100 ppm), rather than sour gas (greater than 1,000 ppm H2S).

Appropriate maintenance practices were determined based on the State of California Safety Orders (2013), the International Fire Code (IFC 2012), National Fire Protection Association (NFPA 2012 and 1013), and API (2005), as well as industry practice. Appropriate maintenance would include:

- An established computerized maintenance management system, including record keeping, design review, maintenance checklists, diagnostics recording, preventative scheduling, and monitoring.
- For piping and pipelines, visual and ultrasonic or non-destructive testing inspections for corrosion (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 non-destructive testing of process piping would be a function of the corrosiveness of the service. However, a baseline should be established for older piping.
- For vessels, external and internal visual and ultrasonic testing should be conducted every 5 years. Maintenance of vessel bracing and bolting for seismic considerations. Pressure relief to safe locations, preferably closed systems.
- For atmospheric tanks, ultrasonic wall testing every 5 years, bottom examination every 10 years, and appropriate seismic design considerations to prevent failure in an earthquake.
- For valves, checking for small leaks more than once per year, since small leaks are frequently precursors to larger leaks and ruptures. Valves should also be exercised at least annually to ensure operational effectiveness, and should be refurbished periodically, including seal and seat refurbishment or replacement, according to manufacturer's recommendations.
- Pressure relief valves should be pressure checked annually. Pressure relief valves that fail the annual test should be retested within 6 months.
- For equipment that rotates mechanically, such as pumps and compressors, appropriate maintenance may involve replacing seals, oil maintenance, and a number of other operations according to the manufacturers' recommendations. Also, design issues are important, such as redundant systems that allow for more frequent maintenance activities, pressure relief systems that vent to a safe location, and seismic bracing for piping and equipment.
- For sensor equipment, such as lower explosion level, fire eyes, and H_2S sensors, appropriate maintenance would involve replacing sensors when new technology presents a significant improvement in reliability, and conducting quarterly inspections and testing to ensure operational effectiveness, and as per manufacturer's recommendations.
- For control systems, such as level, pressure, vibration, and temperature, annual testing including system actuation to ensure operation.
- Emergency shutdown systems should be checked and exercised annually.
- For fire water systems, testing and exercising annually, pressure testing water header, verification of flow alarms, fire pumps weekly inspection and annual performance test, foam system sampled and analyzed annually.

Comparative Risk

Frequency levels can be assigned to a number of different events in life which can produce fatalities. Generally, risks which are voluntary, such as riding a motorcycle or skydiving, are more tolerated than involuntary risks, such as exposure to nearby accidents. The National Safety Council (NSC 2011) compiles risk statistics on a variety of situations (see Table 4.8-2 below).

These are generally based on the frequency as applied to the general population in the United States. However, some of the statistics, such as riding a motorcycle, are applied to only motorcycle riders, as the odds of suffering a fatality while riding a motorcycle are zero if one does not ride a motorcycle. Also, there is a strong variation in age. For example, the odds of health related deaths, as opposed to accidents, are far higher for the older population. Falls are also much higher odds for the older population. But drowning is higher for the young. Table 4.8-2 indicates the frequency per year and the interval, which are two different ways of describing the same thing. For example, the probability of a single heart attack is 0.0057 in a single year, or once every 170 years or one in 170.

Table 4.8-2 Frequencies for Fatality Events

Event	Frequency per year	Interval, Years
Health (heart attack, cancer, stroke, etc)	$5.7X10^{-3}$	170
Accidents all types	$6.1X10^{-4}$	1,600
Motorcycle accidents (per motorcyclist)	$5.1X10^{-4}$	2,000
Motor vehicle accidents, all US population	$1.5X10^{-4}$	6,900
Poisoning accidental	$9.9X10^{-5}$	10,100
Assault	$6.1X10^{-5}$	16,400
Drowning	$1.1X10^{-5}$	87,500
Fires	$1.1X10^{-5}$	91,700
Complications of medical care	$8.6X10^{-6}$	116,000
Electrocution	$1.3X10^{-6}$	774,500
Lightening	$1.5X10^{-7}$	6,549,800
Explosion and rupture of pressurized device	$1.3X10^{-7}$	7,725,400

Notes: interval is the years between events or the probability per year, one in "..". Sources: NSC 2011

Pipelines

Transportation by pipeline is one of the safest forms of transportation for oil or natural gas. Nonetheless, failures do occur, resulting in fatalities, injuries, and property damage. The recent failure of a 30-inch gas transmission pipeline in a residential area of San Bruno, California, garnered extensive media coverage when it caused seven fatalities and numerous serious injuries and destroyed homes. The San Bruno release reportedly continued for more than 1 hour, which exposed the surrounding area to extensive thermal radiation damage. Spectators reported flames as high as 1,000 feet and damage occurred as far as 600 feet from the release location.

The gas pipeline installed along Valley Drive as part of the Proposed Project would operate at a potentially higher pressure than the gas pipeline in San Bruno (up to 225-465 psi for the Proposed Project compared to 375 psi at San Bruno), but would only be 4 inches in diameter (depending on location) for the Proposed Project (compared to 30 inches in diameter for the San Bruno pipeline) and would therefore produce substantially smaller impacts than the San Bruno case. However, in the absence of appropriate controls, it could burn for an extended period of time as well and it could still create significant risk levels.

Incidents associated with gas pipelines are compiled by the DOT, Pipeline and Hazardous Materials Safety Administration. Between 1993 and 2012, 1,211 total incidents on gas

transmission pipelines caused 42 fatalities and 209 injuries nationwide (DOT 2013). Gas pipeline failure frequencies in this report utilized the DOT failure rates for gas pipelines within California. The base rate of pipeline failure is 4.65×10^{-4} incidents per mile. This rate is for transmission pipelines only. Based on detailed data compiled by the OPS from 2002 to 2004, 63 percent of incidents produced leaks and 37 percent produced ruptures. This analysis used these leak and rupture rates.

The OPS database also lists incidents by cause, which are listed in Table 4.8-3. Corrosion, both internal and external, third-party excavation, equipment failures, and 'other' activities are the leading causes of gas pipeline incidents.

Table 4.8-3 DOT National Gas Transmission Pipelines Incident Causes

Cause	Percentage
Corrosion	21.0
Third party damage	20.4
Equipment failure (pipe, welds, valves, etc)	23.6
Other	21.0
Environmental non-earthquake (landslides, etc)	8.3
Earthquakes	3.2
Operational Error	2.2

Source: DOT website, data from 1993-2012

Earthquakes

During earthquakes, ground vibrations and subsequent liquefaction of the soil under structures can collapse and damage buildings and processing equipment. There is no exact correlation between earthquake Richter scale magnitude and ground acceleration values. Earthquakes measuring the same Richter scale value can generate different acceleration values, and thereby equipment damage, depending on the depth and type of ground shaking. For example, the 1994 Northridge earthquake had a magnitude of 6.7 and a peak ground acceleration of 0.94g (g being the acceleration of gravity), whereas the 1971 San Fernando earthquake had a magnitude of 6.7 and a peak ground acceleration of 1.25g.

The distance between the epicenter and the estimated peak acceleration location can also vary. The estimated distance to the peak ground acceleration in the Northridge earthquake was double the distance in the San Fernando earthquake. The distance to the peak acceleration value can be as much as 24 miles. This indicates that areas of damage are not limited to the epicenter of an earthquake.

Equipment damage can be understood by examining damage to equipment during past earthquakes.

The assessment for this EIR examined reconnaissance reports published by the Earthquake Engineering Research Institute for these earthquakes (the reports are not available for all earthquakes):

- Imperial in 1979;
- Northridge in 1994;
- Coalinga in 1983;
- Santa Barbara in 1978;
- Whittier Narrows 1987; and
- Loma Prieta in 1989.

Among the earthquakes examined for this report, most process industry equipment damaged during the earthquakes was related to atmospheric oil or water storage tanks (non-pressured generally larger cylindrical tanks, such as the crude oil tanks proposed for this Project) that ruptured or developed severe seam leaks. Piping connected to the atmospheric tanks often ruptured. Vessels that were not anchored showed some sliding and pipes leaked when the equipment shifted. However, no pressurized vessels failed and no gas liquids (e.g., propane or natural gas liquids) were released during any of the studied earthquakes.

The California Department of Conservation's Division of Oil, Gas and Geothermal Resources (DOGGR) 1984 annual report presents results of drill operator surveys in the Coalinga area to assess damage to drilling and processing equipment after the 1983 magnitude 6.3 Coalinga earthquake (with a peak ground acceleration of 0.54g measured 5 miles away, although no accelerometers were located in Coalinga). The survey indicated that more than 40 atmospheric tanks significantly leaked due to the earthquake. Impact to vessels, compressors, and processing equipment was limited to some shifting and failed equipment tie-downs and fittings, but there were no significant material releases. Some wells sustained damage to downhole casing, but no releases occurred.

Earthquakes are difficult to assess in a QRA. Earthquakes can have a range of magnitudes and ground acceleration values, and their impact on equipment is a function of the ground shaking characteristics as well as acceleration. The approach taken in this study is similar to that used as part of the Environmental Protection Agency (EPA) Resource Management Plan and the California Accidental Release Program. Seismic probability assessments are conducted on a facility to estimate the maximum credible earthquake, and seismic engineers assess the equipment to ensure that it can withstand an earthquake of the maximum credible magnitude. Any deficiencies are corrected to ensure that the facility is seismically safe. This approach essentially assumes that, given good seismic engineering practices and design, a rupture release would not occur in the event of the largest credible earthquake. This approach is supported by the earthquake damage reports discussed above, which provide evidence of the advantages of good engineering design.

However, in this report, it is assumed that atmospheric storage tanks could fail given a large magnitude earthquake producing peak ground acceleration values exceeding 0.50g. A peak ground acceleration value of 0.50g would occur approximately once every 1,500 years for the Project Site location, based on the US Geological Survey analysis, and this value is included in the atmospheric tank failure frequency.

It was also assumed that an earthquake producing greater than 1.5g would cause releases from the pipeline, based on the damage seen in the Earthquake Engineering Research Institute reports discussed above. That is estimated to occur about once every 50,000 years as per USGS data (USGS 2013). Note that the DOT pipeline data, 3% of releases from gas transmission pipelines have been caused by earthquakes.

Failure Rate Uncertainty

There are several sources of variation in the failure rate numbers. These sources include the equipment types and boundaries; the severity of the processes; the application and environment of the equipment; the equipment's age and maintenance history; construction suitability; and interpretations of data gathering at the facility levels.

It should be emphasized that the approach taken to estimate the equipment failure rates in this study is an approximation. The large number of variables involved and the relatively sparse information available, particularly related to age influences on equipment failure rates, necessitates a best estimate approach. Ideally, the most accurate data would be obtained from several facilities exactly like the Proposed Project, using the same methods to gather data, the same type of equipment, and the same services over many years. Unfortunately, failure data is not gathered specifically enough to obtain statistically significant numbers for the exact variables that match the facility. For example, all of the databases include some equipment that is old and some that is relatively new, so there is some duplication in the approach to estimating equipment failure rates and the associated rates as a function of age.

The Center for Chemical Process Safety includes the variability in frequency numbers and provides a high, low, and a mean value for a range of equipment. These ranges show that frequency numbers for equipment average a high of 3.6 times the mean, and a low of 0.0042 times the mean failure rate value.

Consequence Analysis

The consequence analysis and hazard modeling consider the physical effects of a release and its damage to people. The analysis judges the severity of potential hazards associated with accidents and their possible consequences.

Risk assessments typically evaluate fire, flammability, explosion, and toxicity. Fire and flammability hazards are relevant for flammable vapors with relatively low flash points, such as propane and methane; their hazard is usually thermal radiation from vapor jet or vapor cloud fires. In addition, larger vapor jet fires can also lead to a loss of structural integrity of other storage or process vessels. The temperature in flame jets is usually high, and flame impingement onto nearby equipment is of concern.

The release and ignition of flammable vapors may also cause an explosion or a deflagration. The blast overpressure hazard depends on the nature of the chemical, the strength of the ignition source, and the degree of confinement. Deflagration impacts are related to burns and exposure to flame fronts.

Finally, toxic chemicals can produce adverse effects to humans. The degree of these effects depends on the toxicity of the material and the duration of the exposure.

Performing state-of-the-art hazard assessment requires a combination of sophisticated analytical techniques and extensive professional experience. The models in this analysis are the result of more than two decades of development, and they have been validated using large-scale field tests.

The hazard assessment models used as part of this analysis can be categorized into two groups:

- Release rate models; and
- Vapor dispersion models.

The following sections discuss the general characteristics of each of the models used in this analysis. Specific models used in the analysis were selected based on the scenarios identified in the hazard identification task.

Release Rate Models

Several models were utilized to simulate potential releases of gas, liquefied petroleum gas, natural gas liquids, and crude vapor, and two-phase releases from pipes and vessels.

One of the first steps in consequence modeling is to establish the source terms (i.e., release rate, temperature, pressure, and velocity) associated with each scenario. The release rate is the rate at which the material is released from the pipe or vessel to the atmosphere. Before the source terms can be estimated for each scenario identified in the hazard analysis, the thermodynamic and physical properties of each hydrocarbon stream must be characterized. The thermodynamic and physical properties of the hydrocarbon streams were estimated using the IoMosaic SuperChems ™ model, which utilizes numerous thermodynamic and physical property estimation techniques.

The SuperChems™ model also simulates the release of multi-component liquid and vapor streams 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.

Two-Phase Flashing Flow Model

This is a critical two-phase flashing flow and multi-component liquid discharge model based on methodology validated by experimental data in recent literature. "Flashing" is a term used to define the rapid vaporization of gasses that are stored as liquids under pressure and then rapidly vaporize, or flash, when released, like propane. Multi-component are processes that contain different materials mixed together, like a process containing propane, methane and pentane, for example. The data have demonstrated that, for a pipe length exceeding approximately 4 inches, regardless of pipe diameter, there is enough residence time for a discharging flashing liquid to establish equilibrium in the pipe. The output of the model gives a mass release rate and defines the properties of the exiting hydrocarbon aerosol mixture.

The two-phase flashing flow model was used to estimate release rate characteristics for the scenarios where potential aerosol formation could occur as a result of rapid vessel or pipeline decompression and cooling or where pressurized liquids (e.g., gas liquids) could be released, such as a propane release.

Steady and Non-Steady Release from a Pressurized Vessel or Pipeline

These numerical steady and non-steady state flow models are used to compute multi-component liquid and vapor release rates from a ruptured valve or pipeline. The steady-choked and un-choked flow models compute a single release rate assuming uniform pressure and temperature in the vessel. Choked flow is defined as flow where the velocity could approach the speed of sound (sonic velocity) in the fluid, thereby limiting, or "choking" the flow rate. In most rupture releases from pressure vessels, the pressure inside is sufficiently high that choked flow (i.e., releases at sonic velocity) conditions exist during most of the release period. However, in smaller pressure vessels, or for relatively larger release rates, the conditions inside the vessel are not steady. The pressure drop influences the flow velocity and, thus, the mass flow rate. In addition, the density and temperature inside the vessel are also changing. The unsteady state models compute a time-dependent release rate profile based on the chemical component properties.

The modeling method for release rate is to simulate the initial and the average release rate from a pipe or vessel rupture based on the operating conditions: the temperature, pressure, and composition. The initial release rate is then assumed to be steady for the duration of a flammable release (the average release rate is used for a toxic release) until the inventory is expelled or a system shutdown intervenes.

Dispersion Models

Dispersion is the spreading out of a released material into the atmosphere after it has been released and is a function of the material type, temperature, and meteorological characteristics at the time of the release. Among the models required for hazard assessment, vapor dispersion models are perhaps the most complex. This is due to the varied nature of release scenarios, as well as the varied nature of the chemicals that may be released into the environment. The user must select the exposure limit carefully, to reflect both the impact of interest (e.g., fatality, serious injury, injury) and the scenario release conditions (particularly the duration of the release).

In dispersion analysis, gases and two-phase vapor-liquid mixtures (where some aerosols of liquid are comingled with the vapor/gasses, thereby affecting the dispersion) are divided into three general classes:

- Positively buoyant;
- Neutrally buoyant; and
- Negatively buoyant.

These classifications are based on density differences between the released material and its surrounding medium (air) and are influenced by release temperature, molecular weight, ambient temperature, relative humidity, and the presence of aerosols.

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 the case 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, due to the cooling effect, 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 recent research dramatically indicate the importance of heavy gas dispersion in chemical hazard assessment; for these reasons:

- The initial rate of spreading 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, this effect is important when considering large releases of pressurized flammable chemicals. In addition, dispersion analysis is also a function of release modes, which are divided into several categories:

- Instantaneous release (puff);
- Continuous release (plume);
- Momentum-dominated continuous release (jet); and
- Time-dependent continuous releases (jet/plume).

For instance, a momentum-dominated jet will dilute much faster than a plume due to increased entrainment of air caused by the jet. This is especially important when simulating the release of compressed gases.

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

- Prevailing atmospheric conditions;
- Limiting concentration;
- Elevation of the source;
- Surrounding roughness and terrain; and
- Source geometry.

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, it is usually prudent to exercise the model, at a minimum, for both typical and worst-case weather conditions.

Limiting concentration is the concentration at which human health effects would begin to occur. Lower concentrations of concern lead to larger dispersion distances. As with source release rates, 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 10.

Source elevation is 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 a function of the presence of trees, shrubs, buildings, structures and other surface features, 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 require an area source model. Source geometry effects are significant when considering near field dispersion (less than ten times the characteristic dimensions of the source). At farther distances, the source geometry effects are less significant and eventually negligible.

Plume Dispersion Models (Atmospheric)

For the estimation of the distance that a release could impact, or the hazard zones, for low to zero velocity releases involving flammable or toxic materials, a set of neutrally buoyant Gaussian plume models are available. The effects of initial density are usually small in the computation of far field dispersion zones.

Several mathematical variations are included in the models. They have also been computerized as part of the IoMosaic SuperChems™ modeling package for ease of use. Additional models, rigorously evaluated, are available in the public domain. These models have been validated using large-scale field tests and wind tunnel experiments. The variations in these models consider the details of the source effects (as opposed to the virtual source method). They include:

- A continuous line or plane source model (to approximate finite size source effects from evaporating pools, overflowing dikes, etc.);
- A continuous point source plume model (isolated stack) including effects of buoyancy and momentum (jets);
- A finite duration point source model for concentration;
- A finite source duration and receptor duration to model dose effects from a point source; and
- A finite duration "probit" model which accounts for a non-linear dose response relationship.

As a function of downwind distance, each of these models evaluates concentration and width of the dispersing vapor cloud at both source and ground level.

Dense Gas Dispersion Model

The SLAB model for dense gas dispersion was used to model the high pressure gas releases and the gas liquids releases. This model has been validated against experimental data and is available in the public domain. It is appropriate for gas releases, which become cold when they expand from high pressure to atmospheric pressure upon escape from a pipe or vessel. 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. NTIS publication DE91-008443, available from the EPA, contains more details on the SLAB model.

A number of sources discuss the effects of jet entrainment and momentum dominated jets, including Lees's "Loss Prevention in the Process Industries," and the CCPS's "The Use of Vapor Cloud Dispersion Models" and "Vapor Cloud Source Dispersion Models Workbook." The Center for Chemical Process Safety discusses jet entrainment and momentum dominated jets. For releases from pressurized pipes and vessels, if the pressure exceeds two times the ambient pressure, then the flows are generally sonic, with speeds up to 400 m/s, and produce significant jet entrainment issues.

Several studies have validated the jet models in large-scale controlled releases at the Burro trials, Coyote trials, Desert Tortoise, and the Goldfish trials (Chan and Ermak 1983, Koopman 1983, and Morgan 1983).

It should be noted that using a jet model for the near-field dispersion produces smaller hazard zones than a simplified Gaussian model because 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, subsequently smaller hazard zones. Jet effects can reduce hazard zone estimates by up to 50 times over the simplified Gaussian estimates (CCPS, Lee). Given the extensive field validation of the effects of jets and near-field air entrainment, it is believed that the jet models are a more realistic estimate of hazard distances than the simplified Gaussian models.

Flame Jet Model

A flame jet can occur if pressurized gas is released and encounters an ignition source, thereby producing a flaming jet emanating from the release location and causing impacts through thermal exposure. This model is designed to simulate turbulent diffusion flames (flame jets) and can characterize the turbulent flame length, diameter, temperature, and thermal radiation effects. This flame jet 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 potential flammable vapor releases were identified.

The model was also used to assess the impacts of multi-component flame jets, which would be those associated with a blowout that contained some crude oil. Gas to oil ratios (GOR) and increased crude oil content (decreasing GOR) affect the flame jet thermal radiation through a number of effects, including slowing down the jet velocity, thereby reducing air entrainment and increasing thermal effects and increasing transmissivity from crude oil smoke thereby reducing thermal radiation. The effects are complicated but genrally the thermal radiation increases with

increasing GOR, although blowouts with a composition GOR down to 100 could still produce offsite impacts.

Unconfined and Partially Confined Vapor Cloud Explosion Model

Flammable gas releases can produce clouds of the released gas and, if an ignition source is encountered, can explode, producing impacts through overpressure. A partially confined deflagration model was used to estimate overpressure levels for each flammable vapor release considered. The pressure-time histories within the explosion chamber (i.e., confined space or vapor cloud) are calculated by the model and are in generally good agreement with small- and large-scale experimental data on methane-air, propane-air, and hydrocarbon mixture vented and unvented explosions. Explosion potential is expressed in terms of trinitrotoluene (TNT) equivalence, and well-known shock wave propagation relationships are used to estimate overpressure levels at specified distances from the explosion.

The potential for unconfined vapor cloud fires and explosions was assessed using the IoMosaic SuperChems™ model. The potential for a vapor cloud explosion versus a vapor cloud fire (deflagration) was assessed based on the physical characteristics of the hydrocarbon stream. Generally, releases of methane into open air would produce a deflagration instead of an explosion as methane requires some "confinement" (within a building) in order to explode. 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 versus TNT curves;
- Minimum amount of mass sufficient to sustain an unconfined vapor cloud explosion;
- Partial vapor cloud confinement and flame reflection characteristics; and
- Explosion efficiencies.

The SuperChems™ model was used to assess whether or not enough flammable mass could accumulate to sustain an unconfined vapor cloud 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 unconfined vapor cloud explosion. In other cases, modeling results showed that vapor cloud ignition would be characterized by a deflagration (i.e., sub-sonic flame velocity) and would not transition to a full detonation (i.e., supersonic flame velocity).

Boiling Liquid Expanding Vapor Explosion Model

A boiling liquid expanding vapor explosion is a sudden loss of containment of a liquid that is above its boiling point (at atmospheric conditions). A boiling liquid expanding vapor explosion results in a sudden, vigorous liquid boiling and the production of a shock wave. Liquids stored under pressure (such as gas liquids or propane) 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 fireball and radiation.

Note that only the propane refrigeration system proposed at the facility would have the inventory of gas liquids to produce a BLEVE. Gas liquids removed as part of the gas processing would be mixed with the crude oil and not stored in any appreciable quantity at the site.

Boiling liquid expanding vapor explosions were modeled using the SuperChems™ model for fireballs. The approach estimates the total energy that could be produced by the material combustion and 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 boiling liquid expanding vapor explosion was also estimated assuming the vessel fails due to overpressure, and the resulting shockwave is dissipated into the environment. The larger of the hazard zones pertaining to boiling liquid expanding vapor explosions (either overpressure or thermal radiation) was used to estimate risk.

Recent incidents indicate the extent to which gas liquid releases can cause impacts. In December 2006, a propane gas leak in a Milwaukee plant led to an explosion, killing three people and injuring 46 others. The explosion knocked workers off their feet, broke windows in nearby houses and businesses, and scattered burning debris over several blocks. Concussions from the blast were felt miles away (LA Times 2006).

A 1998 incident in Iowa provides valuable lessons regarding propane tank fires and boiling liquid expanding vapor explosions. Vehicle impact sheared ¾" liquid pipe off of an 18,000-gallon propane tank. The excess flow valve on the line was not sized correctly and did not close. The resulting fire engulfed the tank, subsequently causing a boiling liquid expanding vapor explosion. Fire department personnel set up too close to the tank (100 feet) and two people were killed. Fragments thrown from the blast caused additional fatalities.

An incident on October 6, 2007, in Tacoma, Washington, involved a propane tanker truck and propane storage vessels. Reports indicate that a propane-truck driver off-loaded propane that may have leaked. Nearby welding may have created sparks that ignited the fumes. The propane tanker subsequently exploded, apparently damaging the propane storage tanks. The thermal impacts to the propane storage tanks caused the pressure relief devices on the propane storage tanks to relieve, sending a flame jet high into the air. The tanks continued to vent propane and produce a flame jet for multiple hours. The explosion was so intense that part of the tanker truck landed on a nearby highway. Video of the explosion was available on the internet. Video taken approximately 0.25 miles from the explosion indicated a large fireball. However, no overpressure impacts were felt at the video location except for car alarms activated by the pressure wave.

This incident serves to highlight the type of impacts that external events can have on active firefighting equipment, such as deluge systems. The explosion of the propane truck or the flame jets and high thermal impacts of releases effectively would have destroyed any fire-fighting capability of the deluge system. This is why deluge systems are assigned a relatively high failure rate in the fault trees.

Fatality and Serious Injury Rates

Since the release streams are flammable, releases could potentially result in thermal radiation exposure from a fire, and also present an overpressure hazard due to explosions from flammable vapor clouds or boiling liquid expanding vapor explosions. Spills of crude oil and subsequent fires could also cause thermal damage. Damage criteria were developed in order to quantify the potential consequences of an accidental release. Damage criteria are defined as the levels of exposure that could produce fatalities and produce 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. An injury such as lung damage that would require hospitalization and/or other types of therapy would be considered a serious injury.

Thermal Radiation Damage Criteria

The potential concern associated with large-scale compressed gas vapor jet fires is thermal radiation intensity, and its effects on persons, the surrounding structures, processes, and fire suppression equipment. Table 4.8-4 presents an overview of thermal radiation intensity and observed effects. Data presented in these tables show that no considerable physical effect would result from exposure to a radiation intensity between 1 and 1.6 kW/m^2 over extended periods. Exposure to a radiation intensity of 5 kW/m^2 would result in pain if the exposure period was to exceed 13 seconds, and it would result in second-degree burns after 40 seconds. Exposure to a radiation intensity of 10 kW/m^2 would result in pain (5 seconds) and second-degree burns after short exposure periods (i.e., 14 seconds), and death after longer periods.

The time required to reach pain, second-degree burn, and fatality thresholds were 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 and explosions, which are relatively instantaneous. It was assumed in this analysis that some people not within the flame area would move away from the flame to get away from the heat. Analysis of the distances to various radiation levels indicates that this is feasible. Therefore, a less than 1 minute exposure was used as the basis for determining the damage criteria. 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 1 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/m2 would likely begin to generate fatalities in less than 1 minute. All persons exposed to thermal radiation within the flame area were assumed to suffer fatalities regardless of exposure duration.

Table 4.8-4 Thermal Radiation Serious Injury and Impacts

Intensity (kW/m^2)	Impact
1	Time for severe pain - 115 seconds Time for second-degree burns - 663 seconds [a]
1.6	No discomfort for long exposure [b]
2	Time for severe pain - 45 seconds Time for second-degree burns – 187 seconds [a]
3	Time for severe pain - 27 seconds Time for second-degree burns - 92 seconds [a]
4	Time for severe pain - 18 seconds Time for second-degree burns - 57 seconds [a]
5	Time for severe pain - 13 seconds Time for second-degree burns - 40 seconds [a]
10	Time for severe pain - 5 seconds Time for second-degree burns - 14 seconds Time for 100% fatality - 270 seconds [a c]
12.5	Melting of plastic tubing [b]
25	Minimum energy to ignite wood [b]
37.5	Damage to process equipment [b]
100	Time for severe pain - <1 seconds Time for second-degree burns - 1 sec Time for 100% fatality - 11 seconds [c]

a. Based on Handbook of Chemical Hazard Analysis Procedures, FEMA
b. CCPS Chemical Process Quantitative Risk Analysis
c. CCPS Chemical Process Quantitative Risk Analysis using probit equation by Eisenberg

Flammable Vapor Criteria

A release of flammable material can produce impacts by producing a cloud of the flammable material that, if it encounters an ignition source, either explodes or burns (deflagration) back to the material source. Persons located within the cloud when it explodes or burns could be seriously impacted. Whether the cloud explodes or burns is a function of the material and the level of confinement in the environment in which the cloud is located (e.g., within pipe racks, between buildings).

All release scenarios from the Proposed Project could contain flammable vapors. Potential ignition sources onsite are primarily located at the flare or compressor area with other ignition sources mostly associated with drilling or well workover operations or pumps. Several biological and structural explosion damage criteria were reviewed; specifically the Center for Chemical Process Safety reports (CCPS 1989, 1994, 1996). Persons within a structure suffer considerably more damage than persons in the open due to overpressures. This is primarily due to secondary object impacts. Table 4.8-5 details the levels of impacts at various overpressure levels to buildings, equipment and persons.

Table 4.8-5 Overpressure Damage

Overpressure Level	Impact
0.04	Loud noise, sonic boom (143 dBA)
0.15	Glass breakage
0.30	Center for Chemical Process Safety projectile limit, 10% broken window glass, 95% no serious damage. Beyond this the "safe distance"
1.0	Wood trailer roof and walls collapse Unreinforced masonry building partial collapse. partial demolition of houses Estimated 10% fatality/injury rate
5.0	Wood trailer completely destroyed Unreinforced masonry building completely destroyed Utility poles snapped Estimated 100% fatality/injury rate
6.0	Reinforced building major damage/collapse Estimated 40% fatality rate
7.0	Loaded train wagons overturned
12.0	Reinforced building completely destroyed Estimated 100% fatality rate
15.0	Lung hemorrhage, lower range of direct human fatalities

Source: CCPS 1989, 1996

An overpressure level of 0.3 psi would likely result in broken windows and some potential for serious injury. Complete structural damage and serious injury/fatality could occur for wooden buildings and unreinforced masonry as a result of exposure to an overpressure level of 1.0 psi. An overpressure level of 5.0 psi would result in structures being completely destroyed and an estimated 100 percent serious injury/fatality to building occupants.

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 (where the concentration of the gas could allow for ignition) 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 lower flammability limit (a larger area than the lower flammability limit area) would suffer serious injuries.

Hydrogen Sulfide (H_2S) Toxic Criteria

Hydrogen sulfide may be present in the produced gas. Hydrogen sulfide also occurs naturally in sewers, manure pits, well water, and volcanoes. Because it is heavier than air, pure hydrogen sulfide can collect in low-lying and enclosed spaces, such as manholes, sewers, and underground

telephone vaults. Its presence makes work in confined spaces potentially very dangerous. Toxicological effects of H_2S gas at different concentrations are summarized in Table 4.8-6.

Table 4.8-6 Toxicological Effects of H_2S

Concentration (ppm)	Symptoms/Effects
0.00011-0.00033	Typical background concentrations
0.01-1.5	Odor threshold (when rotten egg smell is first noticeable to some). Odor becomes more offensive at 3-5 ppm. Above 30 ppm, odor described as sweet or sickeningly sweet.
2-5	Prolonged exposure may cause nausea, tearing of the eyes, headaches or loss of sleep. Airway problems (bronchial constriction) in some asthma patients.
20	Possible fatigue, loss of appetite, headache, irritability, poor memory, dizziness.
30	Emergency Response Planning Guideline ERPG-2 - the maximum airborne concentration below which it is believed that nearly all individuals could be exposed for up to 1 hr without experiencing or developing irreversible or other serious health effects.
50-100	Slight conjunctivitis ("gas eye") and respiratory tract irritation after 1 hour. May cause digestive upset and loss of appetite.
100	Coughing, eye irritation, loss of smell after 2-15 minutes (olfactory fatigue). Altered breathing, drowsiness after 15-30 minutes. Throat irritation after 1 hour. Gradual increase in severity of symptoms over several hours. Death may occur after 48 hours.
100	Emergency Response Planning Guideline ERPG-3 - the maximum airborne concentration below which it is believed that nearly all individuals could be exposed for up to 1 hour without experiencing or developing life-threatening health effects.
100-150	Loss of smell (olfactory fatigue or paralysis).
200-300	Marked conjunctivitis and respiratory tract irritation after 1 hour. Pulmonary edema may occur from prolonged exposure.
500-700	Staggering, collapse in 5 minutes. Serious damage to the eyes in 30 minutes. Death after 30-60 minutes.
700-1000	Rapid unconsciousness, "knockdown" or immediate collapse within 1 to 2 breaths, breathing stops, death within minutes.
1000-2000	Nearly instant death

Source: OSHA 2013

The health effects of hydrogen sulfide depend on how much H_2S a worker breathes and for how long. However, many effects are seen even at low concentrations. Effects range from mild, headaches or eye irritation, to very serious, unconsciousness and death.

Upon exposure to H_2S concentrations in produced gas of 100 ppm or above, the sense of smell is impaired in 2 to 15 minutes due to paralysis of the olfactory nerve. In addition, death from exposure to still higher concentrations of H_2S gas can occur from lung paralysis before any odor is detected.

According to the California Occupational, Safety and Health Administration (Cal/OSHA), the Permissible Exposure Limit (PEL) of hydrogen sulfide for an employee in an 8 hour work period is 10 ppm with a maximum exposure level of 50 ppm for a maximum period of 10 minutes. OHSA publishes information on the effects of H_2S.

Some people who breathed in levels of hydrogen sulfide high enough to become unconscious continue to have headaches and poor attention span, memory, and motor function after waking up. Problems with the cardiovascular system have also been reported at exposures above permissible exposure limits. People who have asthma may be more sensitive to hydrogen sulfide exposure. That is, they may have difficulty breathing at levels lower than people without asthma (OSHA 2013).

Odorant Toxic Vapor Criteria

Odorant is a material used in the gas processing and is added to the gas stream to give the gas an odor, as required by the Pipeline Safety Regulations of the Department of Transportation, in 49 CFR 192, section 192.625. Processed produced gas does not have an odor. Odorizing the gas system provides a warning device for the public if the gas is released along the pipelines or within homes or businesses. Odorant would be stored and used at the facility.

Toxicological information on tetrahydrothiophene (the odorant) is sparse. However, the National Institute for Occupational Safety and Health (NIOSH) does indicate some toxicity levels for mice and rats, which can be extrapolated to human impacts based on factors of safety for other, better known materials.

A search of the National Library of Medicine's Hazardous Substance Data Bank (HSDB) produced information related to animal toxicity and reports of worker exposures as well as DOT emergency recommendations.

The Registry of Toxic Effects of Chemical Substances (RTECS) by NIOSH indicates that the lethal inhalation concentration of tetrahydrothiophene for a mouse is 27 grams/meter^3 for 2 hours. This is equivalent to approximately 7,300 parts per million (ppm). Using the probit method (with an estimated power factor [n] of 1.5, which defines the curve between lethal dosage and time) results in a lethal inhalation concentration for a mouse of approximately 11,800 ppm per hour exposure. For comparison, the lethal inhalation concentration for a rat for hydrogen sulfide, a well studied lethal and odiferous gas, is 713 ppm per hour. The comparison to hydrogen sulfide is made because of the number of detailed studies of hydrogen sulfide, not because of any similarity in chemical composition.

Using the same factors of safety for tetrahydrothiophene as for hydrogen sulfide, hydrogen sulfide would produce equivalent emergency response planning guideline-2 and emergency response planning guideline-3 values of approximately 500 ppm and 1,600 ppm, respectively (AIHA 2005). In addition, to assess more minor injuries, such as those associated with exposure to strong odors, the hydrogen sulfide Occupational Safety and Health Administration Permissible Exposure Limit (OSHA PEL) of 15 ppm for 15 minutes (or 6 ppm per hour) was also compared. This would be equivalent to 100 ppm per hour of tetrahydrothiophene exposure.

Given the lack of available toxicity data on tetrahydrothiophene, emergency response planning guideline values have been estimated based on the factors of safety applied to lethal levels of hydrogen sulfide exposure for rats and mice. This produces an estimated fatality level at 1,000 ppm per hour and an estimated serious injury level at 100 ppm per hour exposure for tetrahydrothiophene.

Table 4.8-7 details the criteria selected for the risk analysis for both fatalities and serious injuries. In this table, the zero percent fatality or serious injury level is the level at which fatalities or serious injuries could begin to occur.

Table 4.8-7 Fatality and Serious Injury Rates

Event	Fatality	Serious Injury	Assumptions
Vapor Cloud Fire	30% fatality within the lower flammability limit	100% injury within the lower flammability limit 50% injury within ½ lower flammability limit	Assumes 30% of the population is outdoors and would suffer 100% fatalities within the lower flammability limit. Assumes indoor population would not suffer more than serious injury due to subsequent fire and damage. Outdoor population percentage estimated.
Thermal Radiation Jet Fire or Pool Fire	100% fatality within flame jet area 10% fatalities at 10 kW/m^2	100% injury at 10 kW/m^2 10% injury at 5 kW/m^2	Based on Handbook of Chemical Hazards Analysis Procedures, exposure to 10 kW/m^2 produces second-degree burns in 14 seconds, 10% fatalities at 60 seconds based on Eisenberg Probit Equation (1975). Injury based on time to second-degree burns of less than 1 minute for 10 and 5 kW/m^2.
Boiling Liquid Expanding Vapor Explosion: Radiation Dosages	10% fatalities at 80 kJ/m^2	100% injury at 80 kJ/m^2 10% injury at 25 kJ/m^2	Based on total energy integration over boiling liquid expanding vapor explosion duration using the jet fire energy rate.
Explosion: Over Pressure	10% fatalities at 1 psi	5% injury at 0.3 psi	Based on Center for Chemical Process Safety Process Plant Buildings where occupants of a building experience 10% fatality/injury at 1 psi for an unreinforced masonry or wood framed building. Injuries produced at 0.3 psi overpressure assumed to be 5% as per the probability of serious damage.
Toxic	1,000 ppm 10% fatality	100 ppm 10% injury	For odorant - Estimated based on OSHA exposure limits and animal studies.
Toxic	100 ppm	30 ppm	For Hydrogen sulfide: Based on ERPG-2 and ERPG-3

Notes: kW/m^2 = kilowatts per square meter; kJ/m^2 = kilojoules per square meter; psi = pounds per square inch; ppm = parts per million. ERPG based on AIHA 2013 Guidelines

Risk Analysis

The results of the failure rate and consequence analysis are combined to develop risk profile curves (plots of frequency versus the number of fatalities or serious injuries). These risk profile curves are commonly called risk profiles and represent “societal risk.” This is the risk that a person could sustain serious injury or fatality. In calculating the risk profiles, a computer model of the pipelines, facility and surrounding area was prepared. The population distribution and probabilities of ignition were specified across the area of the model; and the likelihood of an individual fatality or injury occurrence was calculated at each grid location in the model.

The analysis has assumed that the populations near the facility are at their current estimated levels would remain so in the future.

To develop the risk profile, 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 of travel, the chances of having the particular wind stability class, the cloud igniting onsite, and the cloud igniting offsite at every downwind location from the release site was evaluated. The frequency of attaining the maximum downwind distances for flammable vapor dispersion will be reduced if the vapor cloud encounters ignition sources at the point of release or at any point along its travel path.

The approach for general calculations followed these steps:

- Summarize meteorological data into representative wind direction, wind speed and stability conditions;
- Construct a model of the site and surrounding area, including populations and population densities;
- Identify the ignition sources and enter the ignition probabilities;
- Select the release events, along with the likelihood of release, consequence data and release locations;
- Determine the event trees; likelihood and consequences of immediate ignition, vapor cloud fires, jet fires, and explosions as appropriate, for each condition;
- Determine the probability of ignition at each point along the path of a dispersing vapor cloud.
- Select another release event and repeat the preceding three steps;
- Apply conditional probabilities of fatality given exposure, for each type of consequence (i.e., thermal exposure, vapor cloud exposure);
- Aggregate the likelihood of all probabilities of fatality at each location in the model for all the release scenarios; and
- Construct risk profiles, or frequency number, of fatality curves by summing the number of fatalities for each event outcome and plotting the results against the frequency. This was also done for serious injuries.

Meteorological Data

Meteorological data was gathered for the King Harbor monitoring location. Stability classes A through F are a means of measuring the amount of atmospheric turbulence present and was developed by Pasquill in 1961. An "A" class is very unstable, whereas a "D" is neutral and "F"

is stable. Atmospheric stability classes D and F were selected as characteristic wind stability conditions for this study.

Based on wind speed conditions for these stability classes, a wind speed of 8.6 mph was selected for stability class D (neutral atmospheric stability), and a wind speed of 4.3 mph was selected for stability class F (stable atmospheric conditions). The predominant conditions are generally wind from the west direction, although wind frequencies from all directions were used in the analysis.

Population Data

Population information was gathered for locations within 1,000 feet of the facility and entered into the Quantitative Risk Assessment Model. Information was gathered from site visits, estimates of populations from housing counts generated from aerial photographs, and from Census data (USCB 2013).

Ignition Probabilities

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 these sources. When determining ignition probabilities, there are two factors to take into account; source duration and source intensity. Source duration is the fraction of time that the source is present or in operation. Source intensity is 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 cloud, but it may only operate ten percent of the time. This would generate an overall chance of ignition 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. Extensive listings of potential ignition sources and estimates of ignition probabilities may be found in the literature (CCPS 1989, UK 2004).

Typical ignition probabilities that were used in the analysis include:

- Cars – 0.06 per car; although many potential ignition sources within a car, such as faulty wiring or backfires, are due to fuel rich mixtures in intake air, they are not always present nor guaranteed to cause ignition (CCPS).
- Houses – 0.01 per house; while there are many ignition sources within a home (switches, doorbells, faulty wiring, pilot lights, smoking materials, fireplaces, and stoves), the flammable vapors must first penetrate the house before these ignition sources pose a hazard. Typical residence times of clouds are brief enough that this is relatively unlikely (CCPS).
- 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 (UKHSE 2004).

In order to estimate the number of vehicles, traffic counts for roads were used (based on the Arch Beach Consulting 2012 traffic analysis by the Applicant and peer reviewed by the EIR

consultant, see Section 4.13 Transportation and Circulation) along with average speeds to determine the density of vehicles per mile and probabilities of ignition along roadways.

For the neighboring operations, a medium industrial use was assumed.

Post Accident Event Trees

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, encounter an ignition source and burn or explode, or it could disperse safely. Table 4.8-8 shows the probability of each of these scenarios for rupture and leak events. These probabilities are based on Center for Chemical Process Safety recommendations (CCPS 1989, 1994). Larger releases, which involve greater energies associated with metal failure and/or impacts, have a higher probability of igniting at the source and causing a flame jet than smaller releases.

Construction of Risk Profiles

Risk profiles display the frequency with which public safety impacts/consequences (e.g., fatalities or serious injuries) exceed a given magnitude. They can be used to show property damage (among others), but are generally used for public safety impacts. The risk profiles indicate accident size (based on numbers of persons affected) and display how the potential number of fatalities varies as a function of frequency. Risk profiles are generally plotted on logarithmic scales because they span multiple orders of magnitude.

There are many sources of uncertainty that affect the risk profiles. These uncertainties include:

- Release frequency;
- Release size;
- Population impacts, including distribution and likelihood of fatality/serious injury;
- Behavior of the release (jet mixing versus passive dispersion);
- Accuracy of the hazard models; and
- Ignition sources and probabilities.

The release frequencies and sizes are the most important contributors to overall uncertainty. Changes in failure rates will directly influence the risk profile. A doubling of the event frequencies would double the probability of fatalities. Changes in the relative sizes of leaks and ruptures will influence the risk profile, but to a lesser extent. The assumptions concerning population distribution and ignition probability also influence the risk profiles.

Table 4.8-8 Event Tree Probabilities

Event Tree: Rupture Events (large releases > 50 kilograms per second)

Event	Probability
Immediate Ignition	0.25
Vapor Cloud with Flash Fire	0.75

Event Tree: Leak Events (smaller releases <50 kilograms per second)

Event	Probability
Immediate Ignition	0.10
Vapor Cloud with Flash Fire	0.90

Event Tree: Gas Liquids Releases

Event	Probability
Immediate Ignition	0.08
Vapor Cloud with Flash Fire	0.90
Explosion/boiling liquid expanding vapor explosion	0.002 - .07*

Notes: * depends on configuration of vessels and piping
Source: CCPS 1989

Spill Risk Analysis Approach

The approach for the spill analysis involved estimating the frequency of release events from the facilities and the release volumes. Spill volumes from a pipeline system rupture are based on the pipeline diameter and the terrain profile, which would limit the amount of oil that could drain out of the pipeline. In addition, the pumping rate also affects the size of a release since oil pumped into the pipeline would contribute to the release size until the pumps are shut down. It was assumed that pumping could continue for 60 minutes for a worst case spill.

Spills contained by the berms and drainage system valves could only be directed outside of the bermed area after a subsequent failure in the drainage discharge procedure or equipment.

Security Risk

Effective and comprehensive site security programs are a prudent aspect of reducing the risk of chemical releases at a facility. Although the Proposed Project area would not be considered a terrorist target on the order of New York or Washington, DC, it could be the subject of vandalism that could release hazardous materials.

The U.S. Department of Homeland Security established chemical facility anti-terrorism standards in 2007 (6 Code of Federal Regulations [CFR] Part 27). This rule established risk-based performance standards for the security of chemical facilities. It requires chemical facilities to prepare security vulnerability assessments that identify facility security vulnerabilities and to

develop and implement site security plans, which include measures that satisfy the identified risk-based performance standards.

The security vulnerability assessments include analysis related to asset characterization, threat assessment, vulnerability analysis, risk assessment, and countermeasure assessments. Generally, facilities covered by the Occupational Safety and Health Administration (OSHA) Process Safety Management and Environmental Protection Agency Risk Management Plan rules are required to comply with these standards.

A number of industry groups, including the American Petroleum Institute (API), the Center for Chemical Process Safety, the Synthetic Organic Chemical Manufacturers Association, American Chemistry Council, and the Chlorine Institute have developed approaches for assessing security risk. Each of these methods involves analyzing the security systems at the facility in combination with the hazards and determining a level of security risk.

Security systems at the site covered by these approaches include:

- Security policies for employees and contractors including access control, pre-employment screening, information security, and post-employment issues;
- Appropriate signage preventing access;
- Fencing systems;
- Visitor sign-in and sign-out;
- Surveillance of hazardous material areas;
- Employee and contractor identification methods;
- Night lighting;
- Partnerships with local response agencies;
- System to report and collect security incidents;
- Communications equipment; or
- Employee vehicles and access keys, codes, and card security.

4.8.1.3 Existing Site Hazards

The current maintenance yard operations involve the use and storage of some hazardous materials associated with vehicle maintenance and fueling. Hazardous materials include relatively small quantities of paint, welding gasses, consumer quantities of solvents, etc. None of these materials are stored in sufficient quantities that they present a risk to the public.

The current storage facility, where the Proposed City Maintenance Yard would be located, does not store hazardous materials.

Some inventory of gasoline and diesel fuel is located within vehicle tanks of the vehicles located onsite. A vehicle accident or mishap could occur which would produce an explosion associated with the spillage of gasoline (within a confined space, for example); however, this risk is common throughout the area with numerous vehicles on the roadways and parked (both onsite and offsite) and is considered to be acceptable due to its low frequency.

The maintenance yard also has a 500 gallon tank of propane that is used for fueling of parking enforcement "gophers" (small vehicles used by the parking enforcement division) and forklifts. The storage and use of propane at the maintenance yard introduces some risk to the area. Figure 4.8-2 shows the estimated risk levels associated with the propane tank as plotted on the FN curves. The FN curves show the consequence (either fatalities or injuries) along the x-axis, and the cumulative frequency along the y-axis. Risk exists in many areas of society, from driving, to filling our cars with gasoline, to existing natural gas pipelines under streets and in homes, and the plots attempt to show the levels of risk and attempt to define areas of risk acceptability. These are used in Europe, Santa Barbara County and by the CSLC. The red and green lines in Figure 4.8-2 show levels of risk that would be unacceptable. Generally, as the number of fatalities or injuries increases (along the x-axis to the right), the frequency at which the event would be acceptable decreases (the lines slope downward to the right). An event that creates a single fatality would be acceptable at a frequency of 1:100,000 but an event that creates 10 fatalities would be acceptable at the lower frequency of 1:1,000,000 (annual probability). The plot of the facility risk is the combination of all of the different release scenarios, their resulting impacts (fatalities or injuries) and the estimated frequency at which they might occur. If the facility risk line falls below the green line, the risks would be acceptable, or less than significant.

Risk levels of the existing propane tank are estimated to be acceptable based on the SBC criteria (see section 4.8.3) and includes the risks of monthly propane deliveries. Certain scenarios have a tendency to define the FN curves, as can be seen in the FN curve for fatalities on the right side of Figure 4.8-2, that produces a right angle based on the single explosion scenario which reaches offsite. None of the other scenarios would reach offsite and cause fatalities; so that single event and its associated probability defines the right-angles FN curve shape.

No underground storage tanks are located at the maintenance yard. Fueling of vehicles (diesel and gasoline) is done offsite.

4.8.1.4 Existing Site Contamination

Historical activities at the current City Maintenance Yard site which may have contributed to site contamination are listed below as detailed in numerous historical reports.

- Former landfill present onsite from the 1920s to 1950s with resulting contamination in the northeast area;
- Former steel underground storage tanks (USTs) and related piping and dispenser equipment were reportedly removed from the site by the City of Hermosa Beach in 1989 and 1998. A previous Phase II Environmental Site Assessment (ESA) performed by ENTRIX indicated that chemicals of concern were not present in the area of the UST location;
- Old Maintenance Building (most northerly building) including a paint room, vehicle maintenance room, a parts room and a miscellaneous storage room. The results of a Phase II ESA indicated that no chemicals of concern were present within the soil below the old Maintenance Building. The building materials would be assessed for asbestos content and presence of lead based paint, consistent with the requirements of the South Coast Air Quality Management District (SCAQMD).

- Oil Well – Stinnett #1 and associated storage tanks. An oil production well and associated tanks were located on the site. The California Department of Conservation, Division of Oil Gas and Geothermal Resources website shows the well to be plugged and abandoned. ENTRIX investigated the area as part of their Phase II ESA. The results of the Phase II ESA indicated that no chemicals of concern were present within the soil in the former oil well location;
- Asphalt Batching Area. An area utilized for asphalt batching was reported by ENTRIX in a previous Phase I ESA. The area appears to be in use today as a storage area for sand and gravel. A phase II ESA completed by ENTRIX indicated that chemicals of concern were not present within the soil below the asphalt batch area.

The site has been the subject of previous environmental evaluation by GeoResearch (1989) ENTRIX (1994, 1995), GEO-CAL. Inc (1998) and Brycon (2012). The scope and results of the previous environmental assessments are discussed below.

GeoResearch 1989

GeoResearch completed a report outlining the closure of two 550 gallon underground storage tanks on the Site in 1989. The tanks were filled with concrete and abandoned in place as part of the project.

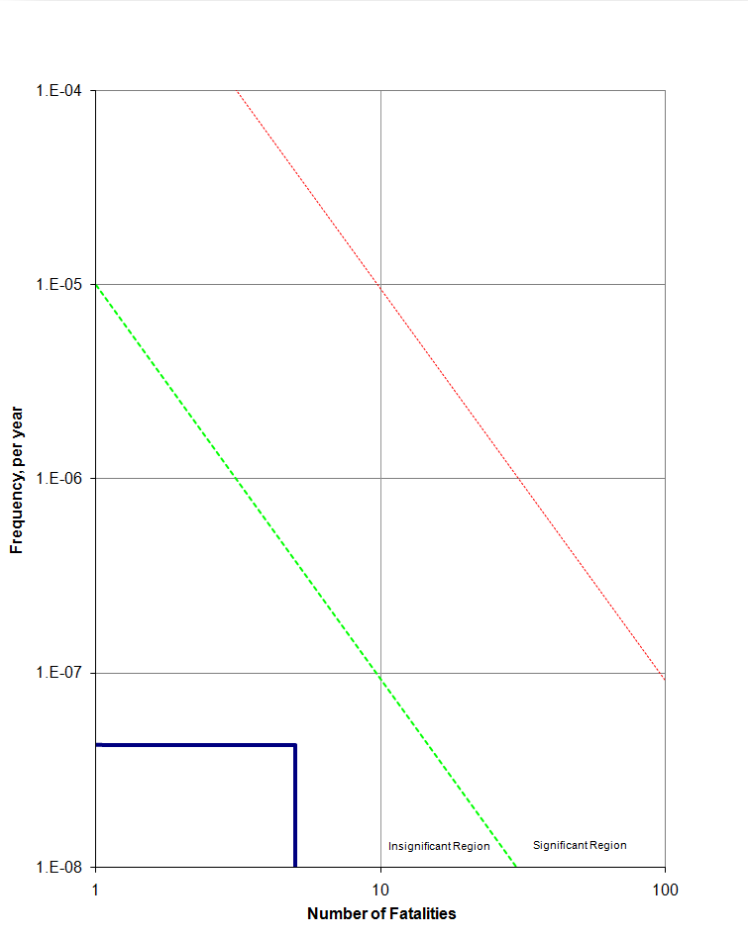
A total of 18 soil samples were obtained from three soil borings and analyzed for total petroleum hydrocarbons (TPH). The analysis detected no TPH in any of the samples. The County of Los Angeles, Department of Public Works issued a closure letter with no further action required for the project on April 10, 1989.

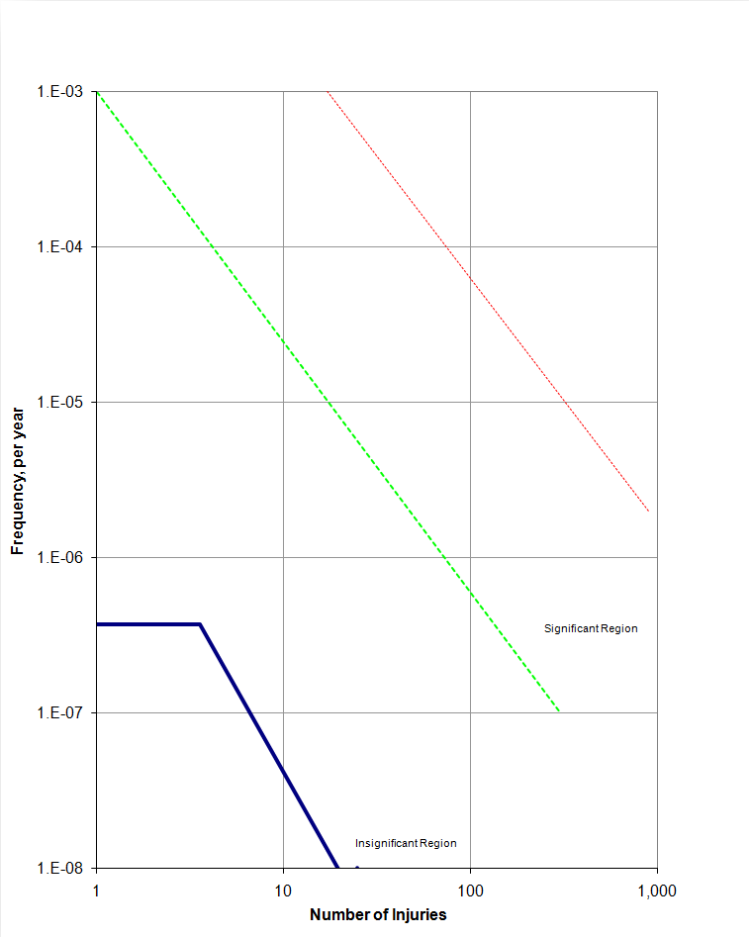
ENTRIX - 1994

ENTRIX, Inc. completed a Phase I ESA (October 1994) on the site. The principal findings were:

1. Several features at the site may have released petroleum and/or solvents at the site. These included a maintenance building, a drum storage area, a vehicle washout area, an asphalt batching area, the Stinnett Oil well, and two underground storage tank settings. Additional sampling was recommended.
2. A soil gas survey was performed on underground storage tanks (USTs) located on the site. Low to non-detectable concentrations of TPH, BTEX, and VOCs were encountered, indicating a significant release from the USTs was not likely.
3. The site history and aerial photo study indicated several concerns including a city dump, possible spills near the Stinnett well, former above ground storage tanks (ASTs) and the former Hermosa Glass Company located on the site of the maintenance building (Paint Room). Additional sampling was recommended.
4. The regulatory database review did not reveal any significant concerns.

Figure 4.8-2 Existing Maintenance Facility Risk Profiles: Fatalities and Injuries





ENTRIX - 1995

ENTRIX, Inc. completed a Phase II ESA (April 1995) on the site in order to evaluate the environmental subsurface condition of the property. Fifteen soil borings were completed across the site at depths of up to 46 feet bgs. Soil samples were obtained and analyzed from various depths within specific soil borings. ENTRIX concluded that petroleum hydrocarbon impacted soil was present on the northeastern portion of the site near the base of the old landfill area in a circular pattern 40 feet in diameter and 20 feet thick at a depth of up to 30 feet. The highest concentration of impacted soil identified by ENTRIX was within soil sample B14D, which was 36,000 milligrams per kilogram (mg/kg) at 20 feet bgs. The calculated volume of petroleum impacted soil by ENTRIX was 700 cubic yards. The analytical reports contained within the ENTRIX document indicated that the TPH present was primarily of longer chain hydrocarbons (C23+). A single point of elevated lead and cadmium impacted soil was identified within the former City landfill area at a depth of 15 feet bgs. ENTRIX concluded that the area of elevated metals was most likely localized and further evaluation was necessary.

GEO-CAL, INC 1998

GEO-CAL, INC. issued a report in 1998 outlining the work completed in regards to the removal of three USTs and associated piping and dispensers. The USTs included two (2) 4,000 gallon gasoline tanks and one (1) 2,000 gallon diesel tank. A total of 12 soil samples were collected and analyzed. Samples were obtained from immediately below each tank (2 per tank), below each dispenser (1 per dispenser), and below the piping trench (1). Three samples were also obtained from the fill material removed from around the tanks. Soil samples collected from below the gasoline tanks and dispenser were analyzed for total petroleum hydrocarbons-gasoline range (TPHg), for benzene, toluene, ethylbenzene, and total zylenes (BTEX), and for Methyl Tertiary Butyl Ether (MTBE). Soil samples from below the diesel tanks and dispenser were analyzed for total petroleum hydrocarbons-diesel range (TPHd), BTEX, and MTBE. Soil samples from the trench and surrounding removed material were analyzed for TPHg, TPHd, BTEX and MTBE. The results of all analytical tests were none detected with the exception of the sample below the diesel dispenser. The result for that sample was 15 mg/kg TPHd. The County of Los Angeles, Department of Public Works issued a Closure Certification and a “no further action” required letter for the project on January 13, 1999.

Brycon 2012

According to a site assessment prepared in 2012 (Brycon 2012), 10 of the 73 soil samples taken exceeded Los Angeles Regional Water Quality Control Board guidelines for total petroleum hydrocarbons, all within the mid range hydrocarbons (C13-C22). Volatile organic carbons were not present in any of the samples at concentrations above the EPA Region 9 Industrial Regional Screening Levels. Six of the samples exceeded the EPA Region 9 Industrial Regional Screening Levels for lead. In addition, a series of groundwater borings conducted in 2013 (Brycon 2013) found the presence of total petroleum hydrocarbons, lead, barium, and arsenic in the groundwater below the City Maintenance Yard that exceed the Maximum Contaminant Levels (MCLs) established for drinking water by the Regional Water Quality Control Board.

Existing site contamination from historical site uses is shown in Figure 2.3 in the Project Description.

The Proposed City Maintenance Yard site had a Phase II Environmental Site Assessment conducted in 2005 (Converse 2005). Based on the analytical results, Converse concluded that the semi-volatile organic carbon impacted soil is at a depth of approximately 2 to 5-feet bgs in the area about the middle of the current building site; that lead impacted soil is located on the northeastern portion of the property approximately 2 to 5-feet bgs in the area near the property line; and that the lead impacted soil may extend offsite; and that an estimated up to 120 tons of impacted soil will need to be excavated and disposed of as non-RCRA hazardous waste.

4.8.1.5 Existing Site Spill Potential

Spill potential from the existing operations is minimal as no large quantities of materials are stored onsite which could spill and affect areas offsite.

A spill outside of the facility would drain into the storm drains. All storm drains in the area eventually flow to the ocean. Figure 4.8-3 shows a map of the storm drain systems in the area.

Storm drains located in the curbs at the corner of Cypress Ave and 6th Street flows through storm drain piping and connects to the main storm drain system in Valley Drive, and flows southerly to connect to the storm drain system in Herondo Street that discharges onto the beach area. The storm drain system that runs down Valley Drive has intermittent street drains for collecting storm water, with drains located near the corner of Valley Drive and 2nd Street. The storm drain systems are under the jurisdiction of both the City of Hermosa Beach and the County of Los Angeles Flood Control District.

Along Herondo Street west of Valley Drive, there is a low-flow diverter system that diverts low flows (from people washing cars, etc) into the sewer system to prevent the buildup and ponding of dirty water on the beach at the ocean discharge. When flows exceed a small amount, the low-flow diverter closes and the flow is directed to the ocean. Small spills would therefore be directed to the sewer system and not the beach.

Figure 4.8-3 Storm Drain System in the Facility Vicinity

Due to sand movement along the beach, the ocean discharge at the end of Herondo Street often gets plugged by sand. When it rains, this plug is either flushed out by the storm drain flow or is manually removed by City staff. A spill at the City Maintenance Yard would have to travel through approximately 0.75 miles of storm drains to reach the ocean. Pictures of the storm drain system are shown in Figure 4.8-4.

Figure 4.8-4 Storm Drain System Pictures

Ocean Discharge on the Beach

Valley Drive and 2nd St.

4.8.2 Regulatory Setting

Many regulations and standards exist to ensure the safe operation of oil and gas facilities, pipelines, and hazardous materials. This section gives an overview of the Federal and State regulations.

4.8.2.1 Federal Laws and Regulations

Federal laws address gas and liquid pipelines and oil and gas facilities.

Gas Pipelines

Natural gas pipelines are under the jurisdiction of the US Department of Transportation (DOT) and must follow the regulations in 49 Code of Federal Regulations (CFR) Part 192, Transportation of Natural Gas by Pipeline. This regulation addresses the following areas:

- Classification of pipeline;
- Pipe type and marking of pipe;
- Pipeline materials and design issues;
- Pipeline fittings and connections;
- Inspection of pipelines;
- Compressor stations and vaults;
- Installation of pipelines;
- Corrosion control; and
- Emergency plans.

Section 49 CFR 192.179 addresses transmission pipeline valves, and requires that, for Class 3 areas (areas where there are more than 46 buildings within 220 yards of a 1 mile section of pipeline, generally residential areas), gas pipelines are required to have a manually controlled valve every 4 miles. Section 192.935c requires that, “if an operator determines, based on a risk

analysis, that an [automatically or remotely controlled valve] would be an efficient means of adding protection to a high consequence area in the event of a gas release, an operator must install the [automatically or remotely controlled valve]. In making that determination, an operator must, at least, consider the following factors—swiftness of leak detection and pipe shutdown capabilities, the type of gas being transported, operating pressure, the rate of potential release, pipeline profile, the potential for ignition, and location of nearest response personnel."

Liquid Pipelines and Oil Facilities

Hazardous liquid pipelines are under the jurisdiction of the DOT and must follow the regulations in 49 CFR Part 195, Transportation of Hazardous Liquids by Pipeline, as authorized by the Hazardous Liquid Pipeline Safety Act of 1979 (49 USC 2004). Other applicable Federal requirements are contained in 40 CFR Parts 109, 110, 112, 113, and 114, pertaining to the need for Oil Spill Prevention Control & Countermeasures Plans; 40 CFR Parts 109–114 promulgated in response to the Oil Pollution Act of 1990.

Overview of the 49 CFR 195 Requirements

Part 195.30 incorporates many of the applicable national safety standards of the:

- American Petroleum Institute (API);
- American Society of Mechanical Engineers (ASME);
- American National Standards Institute (ANSI); and
- American Society for Testing and Materials (ASTM).

Part 195.50 requires reporting of accidents by telephone and in writing for:

- Explosion or fire not intentionally set by the operator;
- Spills of 5 gallons or more, or 5 barrels if confined to company property and cleaned up promptly (prior to 2002, the reporting quantity was 50 bbls);
- Daily loss of 5 barrels a day to the atmosphere;
- Death or injury necessitating hospitalization; or
- Estimated property damage, including cleanup costs, greater than $50,000.

The Part 195.100 series includes design requirements for the temperature environment, variations in pressure, internal design pressure for pipe specifications, external pressure and external loads, new and used pipe, valves, fittings, and flanges.

The Part 195.200 series provides construction requirements for standards such as compliance, inspections, welding, siting and routing, bending, welding and welders, inspection and nondestructive testing of welds, external corrosion and cathodic protection, installing in-ditch and covering, clearances and crossings, valves, pumping, breakout tanks, and construction records.

The Part 195.300 series prescribes minimum requirements for hydrostatic testing, compliance dates, test pressures and duration, test medium, and records.

The Part 195.400 series specifies minimum requirements for operating and maintaining steel pipeline systems, including:

- Correction of unsafe conditions within a reasonable time;
- Procedural manual for operations, maintenance, and emergencies;
- Training;
- Maps;
- Maximum operating pressure;
- Communication system;
- Cathodic protection system;
- External and internal corrosion control;
- Valve maintenance;
- Pipeline repairs;
- Overpressure safety devices;
- Firefighting equipment; and
- Public education program for hazardous liquid pipeline emergencies and reporting.

Overview of 40 CFR Parts 109, 110, 112, 113, and 114

The Spill Prevention Control and Countermeasure plans (SPCC) covered in these regulatory programs apply to oil storage and transportation facilities and terminals, tank farms, bulk plants, oil refineries, and production facilities, as well as bulk oil consumers, such as apartment houses, office buildings, schools, hospitals, farms, and state and federal facilities as follows:

- Part 109 establishes the minimum criteria for developing oil-removal contingency plans for certain inland navigable waters by State, local, and regional agencies in consultation with the regulated community, i.e., oil facilities.
- Part 110 prohibits discharge of oil such that applicable water quality standards would be violated, or that would cause a film or sheen upon or in the water. These regulations were updated in 1987 to adequately reflect the intent of Congress in section 311(b) (3) and (4) of the Clean Water Act, specifically incorporating the provision “in such quantities as may be harmful.”
- Part 112 deals with oil spill prevention and preparation of Spill Prevention Control and Countermeasure Plans. These regulations establish procedures, methods, and equipment requirements to prevent the discharge of oil from onshore and offshore facilities into or upon the navigable waters of the United States. These regulations apply only to non-transportation-related facilities.
- Part 113 establishes financial liability limits; however, these limits were preempted by the Oil Pollution Act of 1990.
- Part 114 provides civil penalties for violations of the oil spill regulations.

Overview of Chemical Facility Anti-Terrorism Standards, 6 CFR Part 27

The Federal Department of Homeland Security established the chemical facility anti-terrorism standards in 2007. This rule established risk-based performance standards for the security of chemical facilities. It requires covered chemical facilities (with chemical quantities above a screening threshold; the Proposed Project would be below these levels) to prepare Security

Vulnerability Assessments, which identify facility security vulnerabilities, and to develop and implement Site Security Plans, which include measures that satisfy the identified risk-based performance standards.

Hazardous Waste Handling Requirements

Resource Conservation and Recovery Act and Associated Hazardous and Solid Waste Amendments, 40 CFR 260

Implementation of the Resource Conservation and Recovery Act (RCRA) resulted in the creation of a major federal hazardous waste regulatory program that is administered by the EPA. Under RCRA, the EPA regulates the generation, transportation, treatment, storage, and disposal of hazardous waste. RCRA was amended by the Associated Hazardous and Solid Waste Amendments (HSWA), which affirmed and extended the concept of regulating hazardous wastes from generation through disposal. HSWA specifically prohibits the use of certain techniques for the disposal of some hazardous wastes. Under RCRA, individual states may implement their own hazardous waste programs instead of RCRA, as long as the state program is at least as stringent as the federal RCRA requirements. The EPA approved California's program to implement federal hazardous waste regulations on August 1, 1992.

Asbestos and Lead

National Emissions Standards for Hazardous Air Pollutants, 40 CFR 61 Subpart M

Under Subpart M, an asbestos containing materials survey must be performed prior to renovation or demolition activities. Notification of the lead agency is required 14 days prior to the start of work (disturbance of asbestos containing materials). Additional federal and state asbestos requirements related to US Occupational Safety & Health Administration (OSHA) standards in 29 CFR 1926.1101 are covered by the Asbestos Construction Standard, Title 8, CCR Section 1529.

Worker Protection Rule, 40 CFR 763, Subpart G, and 29 CFR 1910.1001. This rule provides worker protection measures through engineering controls, worker training, labeling, respiratory protection, and waste management, and sets the permissible exposure level for asbestos. The definition of asbestos containing materials is also provided in these regulations.

Emergency Planning and Community Right-to-Know Act

Under the Emergency Planning and Community Right-to-Know Act, or Title III of the Superfund Amendments and Reauthorization Act of 1986, the EPA requires local agencies to regulate the storage and handling of hazardous materials and requires development of a plan to mitigate the release of hazardous materials. Businesses that handle any of the specified hazardous materials must submit to government agencies (i.e., fire departments), an inventory of the hazardous materials, an emergency response plan, and an employee training program. The business plans must provide a description of the types of hazardous materials and waste onsite and the location of these materials. The information in the business plan can then be used in the event of an emergency to determine the appropriate response action, the need for public notification, and the need for evacuation.

Hazardous Materials Management Planning

Section 112(r) of the Clean Air Act Amendments of 1990, 40 CFR 68

The USEPA requires facilities that handle listed regulated substances to develop Risk Management Programs to prevent accidental releases of these substances. Stationary sources with more than a threshold quantity of a regulated substance shall be evaluated to determine the potential for, and impacts of, accidental releases from that process. Under certain conditions, the owner or operator of a stationary source may be required to develop and submit a Risk Management Program. Risk Management Programs consist of three main elements: a hazard assessment that includes offsite consequences analyses and a five-year accident history; a prevention program; and an emergency response program. Risk Management Programs for existing facilities were required to be submitted in 1999 and must be updated every 5 years.

National Contingency Plan Requirements

Spill Prevention Control and Countermeasures Plans, 40 CFR 112.3 and 112.7

Facilities that store large volumes of hazardous materials are required to have a Spill Prevention Control and Countermeasures Plans (SPCCP), per the requirements of 40 CFR 112. The SPCCP is designed to prevent spills from onsite facilities and includes requirements for secondary containment, provides emergency response procedures, establishes training requirements, and so forth.

Hazardous Materials Transportation

The Hazardous Materials Transportation Act, 49 CFR 171, Subchapter C

The DOT, Federal Highway Administration, and the Federal Railroad Administration regulate transportation of hazardous materials at the federal level. The Hazardous Materials Transportation Act requires that carriers report accidental releases of hazardous materials to DOT at the earliest practical moment. Other incidents that must be reported include deaths, injuries requiring hospitalization, and property damage exceeding $50,000.

Worker Health and Safety

Occupational Safety and Health Act, 29 CFR et seq.

Under the authority of the Occupational Safety and Health Act of 1970, OSHA has adopted numerous regulations pertaining to worker safety (29 CFR). These regulations set standards for safe workplaces and work practices, including the reporting of accidents and occupational injuries. Some OSHA regulations contain standards relating to hazardous materials handling, including workplace conditions, employee protection requirements, first aid, and fire protection, as well as material handling and storage.

Hazard Communication, 29 CFR 1910.1200

The purpose of the OSHA Hazard Communication law is to ensure that the hazards of all chemicals produced or imported are evaluated, and that information concerning any potential hazards is transmitted to employers and employees. This transmittal of information is to be accomplished by means of comprehensive hazard communication programs, which are to include

container labeling and other forms of warning, material safety data sheets, and employee training.

Process Safety Management, 29 CFR 1910.119

Under this section, facilities that use, store, manufacture, handle, process, or move hazardous materials are required to:

- Conduct employee safety training;
- Have an inventory of safety equipment relevant to potential hazards;
- Have knowledge on use of the safety equipment;
- Prepare an illness prevention program;
- Provide hazardous substance exposure warnings;
- Prepare an emergency response plan; and
- Prepare a fire prevention plan.

In addition, 29 CFR 1910.119, Process Safety Management of Highly Hazardous Chemicals, specifically requires prevention program elements to protect workers at facilities that have toxic, flammable, reactive or explosive materials. Prevention program elements are aimed at preventing or minimizing the consequences of catastrophic releases of chemicals and include process hazard analyses, formal training programs for employees and contractors, investigation of equipment mechanical integrity, and an emergency response plan.

Emergency Action Plans, 29 CFR 1910.38

Under this section, facilities that are required to have fire extinguishers must also have an emergency action plan to ensure the safe response to emergencies. The purpose of an emergency action plan is to facilitate and organize employer and employee actions during workplace emergencies. At a minimum, the plan must include the following elements [29 CFR 1910.38(c)]:

- Means of reporting fires and other emergencies;
- Evacuation procedures and emergency escape route assignments;
- Procedures prior to evacuation for employees who remain to operate critical plant operations;
- Procedures to account for all employees after an emergency evacuation;
- Rescue and medical duties for responsible employees; and
- Identification of persons who can be contacted for further information or explanation of duties under the plan.

4.8.2.2 California Laws and Regulations

State laws address gas and liquid pipelines, oil and gas facilities, and hazardous materials and waste. Requirements related to fish and wildlife and spills, under the State Office of Spill Prevention and Response (OSPR), are addressed in Section 4.3, Biological Resources.

California Health and Safety Code

- Division 20, Chapter 6.5, §25100-25249, Hazardous Waste Control;
- Division 20, Chapter 6.95, §255500, et seq., Hazardous Materials Management Plan and Community Right-to-Know and Hazardous Materials Release Response Plans and Inventory (Business Plan Program);
- Proposition 65 Compliance, H&SC §25249.5 et seq.;
- H&SC §§25340-25392, Carpenter-Presley-Tanner Hazardous Substance Account Act; and
- H&SC §§25531-255413, California Accidental Release Prevention Program.

California Water Code

- Division 7, Water Quality (Porter-Cologne Water Quality Control Act)

California Code of Regulations

- Title 8, §1529, Asbestos Construction Standard;
- Title 8, §1532.1, Lead Construction Standard;
- Title 8, §5189, Accidental Release Plan;
- Title 8, §5192, Accidental Release Plan;
- Title 14, Division 2, Department of Conservation;
- Title 19, §2729, Employee Training Program;
- Title 22, Division 4, Chapter 30, Hazardous Wastes;
- Title 22, Division 4.5, §§66260-67786, Hazardous Waste Requirements; and
- Title 22, §66265.50-.56, Contingency/Emergency Response Plan.

Gas and Liquid Pipelines and Oil Facilities

Overview of California Pipeline Safety Regulations

State of California regulations Part 51010 through 51018 of the Government Code provide specific safety requirements that are more stringent than the Federal rules. These include:

- Periodic hydrostatic testing of pipelines, with specific accuracy requirements on leak rate determination;
- Hydrostatic testing by state-certified independent pipeline testing firms;
- Pipeline leak detection; and
- Reporting of all leaks required.

Recent amendments require pipelines to include means of leak prevention and cathodic protection, with acceptability to be determined by the State Fire Marshal. All new pipelines must also be designed to accommodate passage of instrumented inspection devices (smart pigs) through the pipeline.

California Public Resources Code Sections 30260, 30262, and 30265

The California Public Resources Code requires adverse environmental effects to be mitigated to the maximum extent feasible, that new and expanded oil and gas facilities be consolidated, and

that platforms not be sited where a substantial hazard to vessel traffic might result from the facility or related operations.

Department of Conservation Division of Oil, Gas and Geothermal Resources

The DOGGR was formed in 1915 to regulate oil and gas activities with uniform laws and regulations. The Division supervises the drilling, operation, maintenance, and plugging and abandonment of onshore and offshore oil, gas, and geothermal wells, preventing damage to: (1) life, health, property, and natural resources; (2) underground and surface waters suitable for irrigation or domestic use; and (3) oil, gas, and geothermal reservoirs.

Division responsibilities are detailed in Section 3000 of the California Public Resources Code and Title 14, Chapter 4 of the California Code of Regulations. These regulations address issues such as well spacing, blow-out prevention devices, casing requirements, plugging and abandonment of wells, maintenance of facilities and safety systems, fencing, inspection frequency and reporting requirements.

In addition, DOGGR publishes a number of instruction manuals related to testing of oil and gas wells (M06), blowout prevention requirements (M07), and drilling wells in a hydrogen sulfide environment (M10).

The DOGGR is mandated by Section 3106 of the Public Resources Code (PRC) to supervise the drilling, operation, maintenance, and abandonment of oil wells for the purpose of preventing: damage to life, health, property, and natural resources; damage to underground and surface waters suitable for irrigation or domestic use; loss of oil, gas, or reservoir energy; and damage to oil and gas deposits by infiltrating water and other causes.

Section 1774 of Title 14 CCR Division 2, chapter 4 specifies oilfield maintenance practices related to oil field facilities and pipelines.

Written approval from DOGGR is required prior to changing the physical condition of any well. The operator's notice of intent (notice) to perform any well operation is reviewed on engineering and geological bases. For new wells and alteration of existing wells, approval of the proposal depends primarily on the following: protecting all subsurface hydrocarbons and fresh waters; protection of the environment; using adequate blowout prevention equipment; and utilizing approved drilling and cementing techniques.

DOGGR must be notified to witness or inspect all operations specified in the approval of any notice. This includes tests and inspections of blowout-prevention equipment, reservoir and freshwater protection measures, and well-plugging operations. In addition, the operator must have a bond on file with DOGGR before certain well operations can begin. The purpose of the bond is to secure the state against any expenses that the state may incur in obtaining operator compliance with applicable laws, regulations, and orders of DOGGR. The operator must also designate an agent, residing in the state, to receive and accept service of all orders, notices, and processes of DOGGR or any court of law.

Wells that are found to be a hazard are required to be re-abandoned by the operator. If no former operator of the well can be found, DOGGR contracts to have a well be re-abandoned. DOGGR

also maintains a database of historical wells (an abandoned well is located on the Project Site, see Figure 2.3). DOGGR requirements related to construction projects that are near or on top of historically abandoned wells are promulgated by DOGGR, including the submission of plans to DOGGR. The plans that are submitted must illustrate the footprint of all buildings and access obstructions and the surveyed location of all wells. DOGGR may recommend that wells be excavated and tested for leakage and some of the wells may require additional plugging and venting. DOGGR advises not to undertake construction or development that would prevent access to any oil or gas well. Maintaining access to an oil or gas well is defined as 1) maintaining rig access to the well, and 2) not building over, or in close proximity to the well. Close proximity is defined as being within ten feet from the property line and/or structure. DOGGR would oversee and implement requirements related to the existing well on the Project Site.

California Pipeline Safety Act of 1981

This Act gives regulatory jurisdiction to the State Fire Marshal for the safety of all intrastate hazardous liquid pipelines and all interstate pipelines used for the transportation of hazardous or highly volatile liquid substances. The law establishes the Federal Hazardous Liquid Pipeline Safety Act and federal pipeline safety regulations as the governing rules for interstate pipelines.

Oil Pipeline Environmental Responsibility Act (Assembly Bill 1868)

This Act requires every pipeline corporation qualifying as a public utility and transporting crude oil in a public utility oil pipeline system to be held strictly liable for any damages incurred by "any injured party which arise out of, or are caused by, the discharge or leaking of crude oil or any fraction thereof." The law applies only to public utility pipelines, such as those proposed by this Proposed Project, completed after January 1, 1996, or existing pipelines more than 3 miles in length and relocated after January 1, 1996. Signed into law in October 1995, the major features include:

- Each pipeline corporation that qualifies as a public utility that transports any crude oil in a public utility oil pipeline system shall be absolutely liable, without regard to fault, for any damages incurred by any injured party that arise out of, or are caused by, the discharge or leaking of crude oil.
- Damages for which a pipeline corporation is liable under this law are: all costs of response, containment, cleanup, removal, and treatment, including monitoring and administration cost; injury or economic losses resulting from destruction of, or injury to, real or personal property; injury to, destruction of, or loss of natural resources, including but not limited to, the reasonable cost of rehabilitating wildlife habitat, and other resources and the reasonable cost of assessing that injury, destruction, or loss, in any action brought by the State, county, city, or district; loss of taxes, royalties, rents, use, or profit shares caused by the injury, destruction, loss, or impairment of use of real property, personal property, or natural resources; and loss of use and enjoyment of natural resources and other public resources or facilities in any action brought by the State, county, city, or district.
- A pipeline corporation shall immediately clean up all crude oil that leaks or is discharged from a pipeline.

- No pipeline system subject to this law shall be permitted to operate unless the State Fire Marshal certifies that the pipeline corporation demonstrates sufficient financial responsibility to respond to the liability imposed by this section. The minimum financial responsibility required by the State Fire Marshal shall be $750 times the maximum capacity of the pipeline in the number of barrels per day up to a maximum of $100,000,000 per pipeline system, or a maximum of $200,000,000 per multiple pipeline system. For the Pacific Pipeline, the bill specifically requires $100,000,000 for the financial responsibility (section l.h.(l)).
- Financial responsibility shall be demonstrated by evidence that is substantially equivalent to that required by regulations issued under section 8670.37.54 of the Government Code, including insurance, surety bond, letter of credit, guaranty, qualification as a self-insurer, or combination thereof or any other evidence of financial responsibility. The State Fire Marshal shall require that the documentation evidencing financial responsibility be placed on file with that office.
- The State Fire Marshal shall require evidence of financial responsibility to fund post-closure cleanup spots. The evidence of financial responsibility shall be 15 percent of the amount of financial responsibility.

California Accident Release Prevention

The California Accident Release Prevention program mirrors the Federal Risk Management program, except that it adds external events and seismic analysis to the requirements and includes facilities with lower inventories of materials. A California Accident Release Prevention or Risk Management Plan is a document prepared by the owner or operator of a stationary source containing detailed information including:

- Regulated substances held onsite at the stationary source;
- Offsite consequences of an accidental release of a regulated substance;
- The accident history at the stationary source;
- The emergency response program for the stationary source;
- Coordination with local emergency responders;
- Hazard review or process hazard analysis;
- Operating procedures at the stationary source;
- Training of the stationary source's personnel;
- Maintenance and mechanical integrity of the stationary source's physical plant; and
- Incident investigation.

Hazardous Materials and Hazardous Waste

Hazardous Waste Control Law

The Hazardous Waste Control Law is administered by the California Environmental Protection Agency, Department of Toxic Substances Control. Department of Toxic Substances Control has adopted extensive regulations governing the generation, transportation, and disposal of hazardous wastes. These regulations impose cradle-to-grave requirements for handling hazardous wastes in a manner that protects human health and the environment. The Hazardous Waste Control Law regulations establish requirements for identifying, packaging, and labeling hazardous wastes. They prescribe management practices for hazardous wastes; establish permit

requirements for hazardous waste treatment, storage, disposal, and transportation; and identify hazardous wastes that cannot be disposed of in landfills. Hazardous waste is tracked from the point of generation to the point of disposal or treatment using hazardous waste manifests. The manifests list a description of the waste, its intended destination, and regulatory information about the waste.

Hazardous Materials Management Planning

The Office of Emergency Services, in support of local government, coordinates overall state agency response to major disasters. The office is responsible for assuring the State's readiness to respond to and recover from natural, manmade, and war-caused emergencies, and for assisting local governments in their emergency preparedness, response, and recovery efforts. During major emergencies, the Office of Emergency Services may call upon all State agencies to help provide support. Due to their expertise, the California National Guard, California Highway Patrol (CHP), Department of Forestry and Fire Protection, Conservation Corps, Department of Social Services, and the California Department of Transportation (CalTrans) are the agencies most often asked to respond and assist in emergency response activities.

Hazardous Materials Transportation in California

California regulates the transportation of hazardous waste originating or passing through the State in Title 13 of the California Code of Regulations. The California Highway Patrol (CHP) and the California Department of Transportation (CalTrans) have primary responsibility for enforcing federal and State regulations and responding to hazardous materials transportation emergencies. The CHP enforces materials and hazardous waste labeling and packing regulations that prevent leakage and spills of material in transit and provide detailed information to cleanup crews in the event of an incident. Vehicle and equipment inspection, shipment preparation, container identification, and shipping documentation are all part of the responsibility of the CHP. The CHP conducts regular inspections of licensed transporters to ensure regulatory compliance. CalTrans has emergency chemical spill identification teams at locations throughout the State.

Hazardous waste must be regularly removed from generating sites by licensed hazardous waste transporters. Transported materials must be accompanied by hazardous waste manifests.

Hazardous Material Worker Safety, California Occupational Safety and Health Act

The California Occupational Safety and Health Administration (Cal/OSHA) is responsible for assuring worker safety in the handling and use of chemicals in the workplace. Cal/OSHA assumes primary responsibility for developing and enforcing workplace safety regulations in Title 8 CCR. Cal/OSHA hazardous materials regulations include requirements for safety training, availability of safety equipment, hazardous substance exposure warnings, and emergency action and fire prevention plan preparation.

Cal/OSHA also enforces hazard communication program regulations, which contain training and information requirements, including procedures for identifying and labeling hazardous substances. The hazard communication program also requires that Material Safety Data Sheets be available to employees and that employee information and training programs be documented.

Asbestos and Lead

Cal/OSHA defines asbestos-containing construction materials as any internal building component containing greater than 0.1 percent asbestos. This definition is more stringent than federal definitions of asbestos-containing materials, which contain asbestos in concentrations greater than 1 percent. Asbestos-containing materials regulations apply to all building components, including exterior materials and roofing. Lead-containing paint is defined as paint containing 0.006 milligrams per kilogram (mg/kg) lead by weight. Lead-based paint is defined as paint containing 0.05 mg/kg lead by weight. Asbestos and lead hazards associated with facility operations are subject to these rules. Existing asbestos containing materials and lead-based paint surveys cannot identify all materials, especially in or on internal building components. Compliance with 29 CFR 1926.1101, 40 CFR 61 Subpart M (NESHAPS) and similar state laws, requires sampling of suspect or presumed asbestos-containing materials before disturbance, if it is in a quantity of more than 260 linear feet on pipes, or 160 square feet on other facility components, or 35 cubic feet. Cal/OSHA requires registered asbestos abatement contractors to remove asbestos-containing construction materials in quantities greater than 100 square feet.

The Asbestos Construction Standard, Title 8 CCR Section 1529

The Cal/OSHA asbestos standard for construction activities applies to all asbestos work where asbestos-containing construction materials may be disturbed in threshold quantities.

The Asbestos Construction Standard regulates asbestos exposure in all construction work as defined in Title 8 CCR Section 1502, including, but not limited to, the following:

- Demolition or salvage of structures where asbestos is present;
- Removal or encapsulation of materials containing asbestos;
- Construction, alteration, repair, maintenance, or renovation of structures, substrates, or portions thereof, that contain asbestos;
- Installation of products containing asbestos;
- Asbestos spill and emergency cleanup;
- Transportation, disposal, storage, containment of, and housekeeping activities involving asbestos or products containing asbestos, on the site or location at which construction activities are performed;
- Excavation which may involve exposure to asbestos as a natural constituent that is not related to asbestos mining and milling activities;
- Routine facility maintenance; and
- Erection of new electric transmission and distribution lines and equipment, and alteration, conversion and improvement of the existing transmission and distribution lines and equipment.

Cal/OSHA Lead Construction Standard, Title 8 CCR Section 1532.1

The Lead Construction Standard applies to all construction work where an employee may be occupationally exposed to lead. The standard applies to any construction activity that may release dust or fumes including, but not limited to, manual scraping, manual sanding, heat gun applications, power tool cleaning, rivet busting, abrasive blasting, welding, cutting, or torch

burning of lead based coatings. Unless otherwise determined by approved testing methods, all paints and other surface coatings are assumed to contain lead at prescribed concentrations, depending on the application date of the paint or coating.

All construction work excluded from coverage in the general industry standard for lead by Section 5198(a)(2) is covered by this standard. Construction work is defined as work for construction, alteration, and/or repair, including painting and decorating. It includes, but is not limited to, the following:

- Demolition or salvage of structures where lead or materials containing lead are present;
- Removal or encapsulation of materials containing lead;
- New construction, alteration, repair, or renovation of structures, substrates, or portions thereof, that contain lead, or materials containing lead;
- Installation of products containing lead;
- Lead contamination/emergency cleanup;
- Transportation, disposal, storage, or containment of lead or materials containing lead on the site or location at which construction activities are performed; and
- Maintenance operations associated with the construction activities.

4.8.2.3 Local Laws and Regulations

Los Angeles County

Los Angeles County has established a number of programs and plans to address oil and gas operations in the County.

Los Angeles Municipal Code (Fire Protection – Chapter 5, Section 57, Divisions 4 and 5)

These portions of the municipal fire code regulate the construction of buildings and other structures used to store flammable hazardous materials, and the storage of these same materials. These sections ensure that the business is properly equipped and operates in a safe manner and in accordance with all applicable laws and regulations. The Los Angeles County Fire Department issues these permits.

Los Angeles County Certified Unified Program Agency

The Certified Unified Program Agency is designed to consolidate, coordinate, and consistently administer permits, inspection activities, and enforcement activities throughout the County. The Los Angeles County Fire Department is the Certified Unified Program Agency for the entire County except in the cities of El Segundo, Glendale, Long Beach, Los Angeles, Santa Fe Springs, Santa Monica, and Vernon; these cities are Certified Unified Program Agencies within their own jurisdictions. The Los Angeles County Fire Department manages the hazardous materials disclosure program administered under Health and Safety Code Chapter 6.95 and California Code of Regulations Title 19 (19 CCR) and requires the submittal of a hazardous materials inventory and contingency plan if the business handles or stores hazardous materials.

Los Angeles County General Plan

The Board of Supervisors adopted the first Safety and Seismic Safety Elements as components of the Los Angeles County General Plan in 1975 and updates in 1990. The Safety Element addresses earthquake, landslides, flood and fire hazards; and potential hazardous materials incidents related to these hazards. The specific policies of the General Plan (Policies 20 and 21 of the Safety Element) state that the County should:

> Review proposed development projects involving the use or storage of hazardous materials, and disapprove proposals which cannot properly mitigate unacceptable threats to public health and safety to the satisfaction of responsible agencies. And promote the safe transportation of hazardous materials.

Los Angeles County Fire Department

The Los Angeles County Fire Department Hazardous Materials Section is the administrative agent for the California Health and Safety Code, California Code of Regulations related to Emergency Planning and Community Right to Know laws, and Federal Superfund Amendments and Reauthorization Act Title III.

The Los Angeles County Fire Department Hazardous Waste Control Program regulates the disposal, handling, and storage of hazardous and toxic materials. Its purpose is to protect the County of Los Angeles from accidental spills or releases of hazardous materials. It accomplishes this through inspections, emergency response enforcement, and site mitigation.

The Los Angeles County Certified Unified Program Agency (LACoCUPA) established its Site Mitigation Unit (SMU) in 1986. SMU's voluntary oversight program operates per Health and Safety Code §101480 which allows oversight of certain contaminated sites. In addition, in May 2008, Department of Toxic Substances Control (DTSC) delegated corrective action oversight authority to LACoCUPA under chapter 6.5 of Division 20 of California Health and Safety code to implement corrective action under consent agreement at CUPA facilities within its jurisdiction. SMU voluntary oversight and corrective action oversight programs are options in addition to DTSC and Regional Water Quality Control Board (RWQCB) oversight programs for residents and businesses of Los Angeles County seeking oversight in a cost effective and timely manner for cleanup of their contaminated properties.

County Code Chapter 12.60 Hazardous Materials—Site Assessment/Remediation directs that the provisions of the chapter shall apply to all the unincorporated and incorporated areas of the county within the jurisdiction of the Los Angeles County Certified Unified Program Agency. A site assessment/remedial investigation is required whenever there is a suspected escape, spill or release of hazardous materials into the environment or for the purpose of determining applicability of the hazardous waste control laws. A remedial action is required whenever it is determined that there was an escape, spill or release of hazardous materials into the environment which may pose a significant threat to human health or the environment. No person shall engage in the process of site assessment/remedial investigation or remedial action on a site, where a hazardous material release may have occurred and which is under the jurisdiction of the forester and fire warden or where oversight is requested from the forester and fire warden, until an

application for oversight has been submitted to and approved by the health hazardous materials division, site mitigation unit of the forester and fire warden pursuant to this chapter.

City of Hermosa Beach

The City of Hermosa Beach adopted Ordinance No. 85-803 on June 25, 1985 establishing the Hermosa Beach Oil Code and adding Chapter 21A to the Municipal Code. The purpose of the Oil Code is to "regulat[e] the development and design of oil recovery and establishing a permit system for drilling and oil recovery operations". Subsequent to the adoption of the oil code, the voters passed ballot Measure E prohibiting all oil development within the City. The Oil Code addresses the following areas:

- Permits;
- Well location;
- Derricks and blowout protection;
- Development standards;
- Noise;
- Abandoned and idle wells;
- Storage;
- Fire prevention;
- Enforcement and review procedure; and
- Permit revocation procedures

The Proposed Project would revoke the general provisions of the oil code and incorporate specific regulations governing standards and procedures, to the extent that procedures are not part of the City's permit processes that would apply to E&B's Project into the Development Agreement that will be concurrently presented to the Hermosa Beach electorate.

4.8.2.4 Other Applicable Guidelines, National Codes, and Standards

- Safety and Corrosion Prevention Requirements — American Society of Mechanical Engineers, National Association of Corrosion Engineers, American National Standards Institute, and API
- American Society of Mechanical Engineers (ASME) & American National Standards Institute (ANSI) B16.1 Cast Iron Pipe Flanges and Flanged Fittings;
- ASME & ANSI B16.9, Factory-Made Wrought Steel Butt Welding Fittings;
- ASME & ANSI B31.1a, Power Piping;
- ASME & ANSI B31.4a, addenda to ASME B31.4a, Liquid Transportation Systems for Hydrocarbons, Liquid Petroleum Gas, Anhydrous Ammonia, and Alcohols;
- National Association of Corrosion Engineers (NACE) Standard RP0190, Item No. 53071. Standard Recommended Practice External Protective Coatings for Joints, Fittings, and Valves on Metallic Underground or Submerged Pipelines and Piping Systems;
- NACE Standard RP0169, Item No. 53002. Standard Recommended Practice Control of External Corrosion on Underground or Submerged Metallic Piping Systems;
- API 49, Recommended Practice for Drilling and Well Service Operations Involving Hydrogen Sulfide;

- API 54, Recommended Practice for Occupational Safety for Oil and Gas Well Drilling and Servicing Operations;
- API 510 Pressure Vessel inspection Code;
- API 521 Pressure Relieving Systems and Flares;
- API 570 Piping Inspection Code, applies to in-service metallic piping systems used for the transport of petroleum products;
- API 572 Inspection of Pressure Vessels;
- API 574 Inspection Practices for Pipe System Components;
- API 575 API Guidelines and Methods for Inspection of Existing Atmospheric and Low-pressure Storage Tanks;
- API 576 Inspection of Pressure Relieving Devices;
- API 650 Welded Steel Tanks for Oil Storage;
- API 651 Cathodic Protection of Aboveground Storage Tanks;
- API 653 Tank Inspection, Repair, Alteration, and Reconstruction;
- API 2610, Design, Construction, Operation, Maintenance, and Inspection of Terminal & Tank Facilities; and
- API Spec 12B - Bolted Tanks for Storage of Production Liquids.

API 653, atmospheric tank inspection and repair, addresses the following issues:

- Tank suitability for service;
- Brittle fracture considerations;
- Inspections;
- Materials;
- Design considerations;
- Tank repair and alteration;
- Dismantling and reconstruction;
- Welding;
- Examination and testing;
- Marking and recordkeeping;
- Tank inspections;
- External inspections by an authorized inspector every 5 years;
- Ultrasonic inspections of shell thickness every 5 years (when corrosion rate not known); and
- Internal bottom inspection every 10 years, if corrosion rates not known.
- Fire and Explosion Prevention and Control, National Fire Protection Agency Standards

National Fire Protection Agency (NFPA) 30, Flammable and Combustible Liquids Code and Handbook;

- NFPA 11, Foam Extinguishing Systems;
- NFPA 12, A&B Halogenated Extinguishing Agent Systems;
- NFPA 15, Water Spray Fixed Systems;
- NFPA 20, Centrifugal Fire Pumps; and
- NFPA 70, National Electrical Code.

4.8.2.5 Regulatory Oversight

There are a large number of federal, state, local laws and codes and standards which apply to an oil and gas facility. Generally, the regulatory oversight falls into the following categories. This matrix should not be considered all encompassing, but provides for a general understanding of the many different agencies involved in oversight of an oil and gas facility.

4.8.2.6 Oil Spill Response Organizations

In general, oil spill response on land is handled by the area fire departments, with the Hermosa Beach Fire Department and, jointly, the County Fire Department Haz mat unit, responding to a spill in the area. For marine spills, the US Coast Guard responds to, and oversees response activities in combination with private industry-sponsored organizations, like the Marine Spill Response Corporation (MSRC), an oil spill cooperative that is currently the largest U.S. oil spill response organization for coastal and offshore oil spills, which provides spill response support for the Ports and the Chevron Marine Terminal.

4.8.3 Significance Criteria

As defined in the CEQA Appendix G (section VII), the Environmental Checklist Form, a significant safety effect is one in which the Project would:

- Create a significant hazard to the public or the environment through the routine transport, use or disposal of hazardous materials;
- Create a significant hazard to the public or the environment through reasonably foreseeable upset and accident conditions involving the release of hazardous materials into the environment;
- Emit hazardous emissions or handle hazardous or acutely hazardous materials, substances, or waste within one-quarter mile of an existing or proposed school;
- Be located on a site which is included on a list of hazardous materials sites compiled pursuant to Government Code Section 65962.5 and, as a result, would it create a significant hazard to the public or the environment;
- For a project located within an airport land use plan or, where such a plan has not been adopted, within two miles of a public airport or public use airport, would the project result in a safety hazard for people residing or working in the project area;
- For a project within the vicinity of a private airstrip, would the project result in a safety hazard for people residing or working in the project area;
- Impair implementation of, or physically interfere with, an adopted emergency response plan or emergency evacuation plan;
- Expose people or structures to a significant risk of loss, injury, or death involving wildland fires, including where wildlands are adjacent to urbanized areas or where residences are intermixed with wildlands.
- For site contamination, result in mobilization of contaminants currently existing in the soil and groundwater, creating potential pathways of exposure to humans or other

sensitive receptors that would result in exposure to contaminant levels that would be expected to be harmful; or

- For site contamination, result in the presence of contaminated soils or groundwater within the project area, and as a result, expose workers and/or the public to contaminated or hazardous materials during construction activities at levels in excess of those permitted by Cal/OSHA in CCR Title B and the federal OSHA in Title 29 CFR Part 1910.
- For site contamination, result in the presence of contaminated soils or groundwater within the project area, and as a result, expose workers and/or the public to contaminated or hazardous materials during construction activities at levels in excess of those permitted by Cal/OSHA in CCR Title B and the federal OSHA in Title 29 CFR Part 1910.

Table 4.8-9 Regulatory Oversight Responsibilities

Oversight Area	Federal EPA	Federal DOT	Federal/Cal OSHA	State DOGGR	State RWQCB or DTSC	State OES	State CalTrans	State Fire Marshal	State DFW	State CCC	LA County FD/CUPA	Local FD	Local AQMD	Local Jurisdiction/City
Cleanup of spills	X				X	X					X			
Compliance with permit conditions and local codes				X						X	X	X		X
Emergency response plan preparation, hazardous materials plans	X					X			X		X	X		
Emissions of toxic and hazardous materials	X												X	
Inspections of facilities for code compliance	X		X	X							X	X		
Pipeline transportation of hazardous materials		X						X						
Responding to emergency scenarios, conducting drills, etc				X				X	X			X		
Site contamination issues	X				X						X			
Spills of hazardous materials	X			X	X				X			X		
Storm water discharges					X									
Truck transportation of hazardous materials							X							
Worker safety and workplace conditions			X											

Because neither the City of Hermosa Beach nor Los Angeles County have established public safety thresholds, the thresholds below, modeled after the Santa Barbara County General Plan (SBC) Public Safety Thresholds adopted in August 1999, have been used in this analysis. These thresholds have been used for EIRs by the California State Lands Commission as well as other

local jurisdictions within Southern California (Los Angeles County, the City of Whittier) to determine if a project presents a "significant hazard to the public".

In addition, a Safety Element Supplement was adopted by SBC in February 2000 (Board of Supervisors Resolution 00-56) covering hazardous materials. The objective of the Safety Element is to define unacceptable risk in a manner that guides consistent and sound land-use decisions involving hazardous facilities. As part of this objective, SBC defined unacceptable risk involving new development, as well as modifications to existing development if those modifications increase risk.

The public risk thresholds utilize FN curves, and consist of three classifications — “green,” “amber,” and “red” — for guiding the determination of significance, based on the estimated probability and consequence of an accident. FN curves are graphs that plot the frequency of scenarios vs. the consequences (the number of fatalities or injuries) on a logarithmic scale.

In summary, the thresholds utilize FN curves to define the significance level of a proposed project or modification. The guidelines indicate that significant impacts would be avoided if the frequency of a single fatality is shown to be less than 1 in 1,000,000 years (the individual specific risk). If the risk of a single fatality is greater than 1 in 1,000,000 years, then a detailed quantitative risk analysis must be completed to indicate whether the risks are below those defined by the FN curves as significant.

A safety and risk impact is considered significant if any of the following apply:

- The estimated probability and consequences of an accident falls within the red or amber zone of the SBC 2000 Safety Thresholds FN curve; or
- Existing or proposed emergency capabilities (including oil spill response plans and other plans that would be used for emergencies) are not adequate to effectively mitigate spills and other accident conditions.

4.8.4 Proposed Project Impacts

The risk analysis for the Proposed Oil Project (both at the Project Site and along the pipeline route) involves developing release scenarios, conducting a frequency and consequence analysis, and then combining these analyses to present a risk analysis. Impacts are then discussed for all aspects of the Proposed Project (the Project Site, the pipeline and the City Maintenance Yard).

4.8.4.1 Design Features

There are a large number of codes and standards and regulatory requirements applicable to the Proposed Oil Project that will help to reduce the risks of oil and gas facilities, including Process Safety Management systems, equipment metallurgical and welding requirements, design requirements related to pressure relief, fire code requirements related to gas detection and fire protection measures and training and emergency response (discussed in Section 4.8.2, Regulatory Setting). The Applicant has proposed additional design features which would further reduce the risk levels of the facility. These include the following:

- Rather than using a shutdown system utilizing cascading shutdowns, if a problem occurs, the entire facility would shut down. The shutdown system would allow for shut-in of all wells and shutdown of the processing system in the event of an emergency;
- Use of vent-to-flare closed-loop systems so that all pressure safety valves are vented to the flare and not to the environment;
- Use of isolation valves within the process to allow for smaller releases of material;
- The installation of H2S monitoring systems during drilling, workover and well servicing operations; and
- The use of off-shore equivalent certified blind shear rams in the BOPE during drilling, such as the use of API RP14C requirements.

4.8.4.2 CUP Requirements

The Proposed Project would be required to comply with the 1993 Conditional Use Permit. Applicable requirements for Safety, Risk and Hazards are listed below.

- A minimum of one annual site audit shall take place to inspect for soil contamination as a result of accidental spills in any areas not paved and exposed. Auditor shall be hired by City;
- The maximum number of days the workover rigs or any other rig that is to be used onsite shall be 90 days per year;
- The maximum size for any storage tank any type shall be forty feet in of diameter and sixteen feet in height;
- Prior to construction and prior to obtaining building permits for oil production, a complete soil analysis shall be performed and approved by all applicable governing agencies having jurisdiction over the Project;
- Not more than five tanks shall be installed, and shall be submerged in a concrete basin which contains 10% above the volume required by the State Division of Oil and Gas and the Uniform Fire Code [note that DOGGR does not regulate the size or volume of storage tanks];
- Except for the drill rig and drawworks, no equipment or appurtenant structures shall exceed 16 feet in height from grade;
- The well cellars shall be concrete lined and shall be designed to hold contaminated run-off from onsite sources; or a sump shall be provided;
- The site shall be enclosed by a solid masonry or concrete wall with solid gates during all operations, protecting both against public entry, observation and attraction. A chain link fence to provide security is acceptable only through the exploratory phase;
- Security personnel shall be employed at all times during the drilling stage (24 hours) and emergency phone numbers shall be posted during production Phase II;
- Security personnel shall be employed at all times during the drilling stage (24 hours) and emergency phone numbers shall be posted during production Phase II
- Signs warning of unauthorized entry and safety hazards shall be posted on all sides.
- Access to facilities shall be limited to authorized personnel only.
- Trees shall be maintained at a distance from all walls to prohibit children and others from unauthorized entry.

- All site personnel shall be instructed on required safety procedures if hydrogen sulfide concentrations are encountered. Documentation of training and instruction shall be made available to the City Personnel Director.
- Both solid and liquid wastes shall be sampled and tested to determine if it needs to be treated as a hazardous waste.
- An Oil Spill Prevention Control Countermeasures (SPCC) Plan and an Oil Drilling Contingency Plan will be prepared for the Project and approved by the State Division of Oil and Gas [note that DOGGR requires a Spill Contingency Plan; SPCC is a Federal requirement], and the city of Hermosa Beach Fire and Building and Safety Departments.
- Drillsite and production facilities shall be constructed in accordance with the State seismic standards, and designed in accordance with U.B.C. seismic requirements for hazardous facilities.
- A soils engineering report and engineering geology report prepared by a licensed geologist and engineer shall be prepared and reviewed in conjunction with the plans for all physical improvements. Said report shall address potential seismic hazards, such as liquefaction, due to soils or geologic conditions. All recommendations contained in said reports shall be incorporated in the construction documents.
- An emergency response plan, including a blowout prevention and control plan, shall be prepared for review and approval by the Division of Oil and Gas and the Hermosa Beach Fire Department [note that DOGGR does not require an emergency response plan and that blowout prevention is only required during drilling and workover operations].
- When a leak or spill occurs, it shall be contained, the fluid shall be recovered and the area restored to its original condition.
- Tanks shall be submerged 6 to 8 feet or more below grade;
- Project Site shall be graded so that all contaminated runoff is collected and treated onsite and disposed of according to all laws;
- Site shall be graded in a manner so that all hazardous or contaminated fluids and runoff are directed toward a cellar and approved pit and disposed of properly;
- No water from the site shall be allowed to enter the storm drainage system or any public area;
- No water from the site shall be allowed to surface flow across the public beach;
- Pipelines shall be designed with ample safety factors, pressure-tested prior to being placed in operation, and monitored for corrosion once in operation;
- Safety shut-down devices that respond to drops in pipeline pressure shall be incorporated into the Project in order to stop the flow of the Pipeline contents in case of a Pipeline rupture;

The CUP also states that, all requirements, standards, conditions stated within the Oil Production Code, Chapter 21-A, of the City's Municipal Code shall be met. Applicable to safety impacts, additional measures listed in the Oil Production Code include:

- No process operations shall be permitted at any well site.
- No oil well shall be drilled within twenty (20) feet of the exterior boundary of any dedicated public street, highway or private street except wherein a greater distance is required by state statutes or the Division of Oil and Gas [note that DOGGR does not

specify setback distances of wells from public or private structures, improvements or streets, as per DOGGR comments];

- No well shall be located within twenty (20) feet of any building, nor shall any such building be erected within twenty (20) feet of any well not abandoned, except buildings incidental to the operation of the well.
- Prior to commencement of any drilling operation, all private roads used for access to the drill site and the drill site itself shall be maintained in such manner so as to minimize dust and mud.
- In oil operating areas all open, accessible surface excavations used for the disposal of waste liquids and all well production equipment having external moving parts hazardous to life or limb shall be attended twenty-four hours per day or be enclosed by fencing;
- If oil or other liquid storage facilities are established incidental to a producing well on a drill site, the total capacity of such storage facilities shall not exceed two thousand barrels per well. Sumps shall not be used for the storage of any oil or other liquids;
- All electrical equipment used, installed or maintained within fifty feet of a drilling well and within twenty-five feet of a producing well shall be in accordance with the provisions of N.F.P.A. Standard No. 70, Article 501 governing Class l, Division 2, Hazardous Locations;
- No internal combustion engine (except those used for the drilling, redrilling, or servicing of a well), storage tank, boiler, fired equipment or open flame (except welding supervised by the production foreman, drilling foreman, drilling supervisor, or safety supervisor) shall be located closer than twenty-five feet to a producing well nor closer than one hundred feet to a drilling well. During drilling operations on a drill site of two acres or less in an area where two or more wells are drilled and drilling and production equipment are located on such sites, the provisions of this code relating to distances of storage tanks may be altered at the discretion of the chief of the fire department after consideration of the private fire prevention measures to be provided
- A minimum of two fire extinguishers shall be maintained at all well locations where drilling, redrilling, workover, or well servicing is being conducted. Each such extinguisher shall have a minimum classification of 20 B as set for in N.F.P.A. Volume No. 10.

4.8.4.3 Characteristics of Crude Oil, Natural Gas, and Odorant

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 carbon dioxide and, sometimes, hydrogen sulfide. Flammable vapors that may emanate from crude oil include methane, propane, butane, and pentane.

Crude oil comes in many forms. Thin and volatile oils are "light," whereas thick and viscous ones are "heavy." Light oils have an American Petroleum Institute (API) gravity of 30 to 40 degrees, which means that the density is much less than the density of water, 1.0 gram per cubic centimeter (g/cc). These oils float easily on water. By contrast, heavy oils have an API gravity of less than about 20 degrees. Oil with the same density of water has an API gravity of 10.

Crude oils are also characterized by Reid vapor pressure. Reid vapor pressure (ASTM Method D 323) is the absolute vapor pressure exerted by a liquid at 100 degrees Fahrenheit (°F). The higher the Reid vapor pressure, the more volatile the oil and the more readily it will evaporate.

Sulfur in crude oil occurs in many natural compounds including hydrogen sulfide. Total sulfur ranges from approximately one to four percent by weight in crude oils, and hydrogen sulfide concentrations can be more than 100 ppm in “sour” crudes. Hydrogen sulfide is a toxic gas that can cause injuries or fatalities if released into the atmosphere and inhaled by persons. Its strong, pungent odor is detectable at a level substantially below that which causes health effects. It also causes paralysis of the olfactory functions at levels lower than those that cause health effects.

Other constituents of crude oil include nitrogen and oxygen compounds, and water- and metal-containing compounds, such as iron, vanadium, and nickel.

API from Redondo Beach wells indicate that the crude oil from the Proposed Project wells is expected to have an API of between 14 and 25 gravity, as per historical records from the Redondo Beach wells. The Applicant indicates an API gravity of 18 is expected.

Hydrocarbon gas is also produced from formations and would be processed at the Proposed Project gas plant. The processed gas must conform to requirements established by Southern California Gas Company (SCGC) for use in their distribution system. The majority of the gas would be methane, with some smaller amounts of ethane, propane, butane, pentane, hexane+, and inert compounds (such as CO2). Natural gas presents hazards due to its flammability in the form of vapor cloud fires and explosions, and thermal radiation impacts due to flame jet fires emanating from a gas leak or rupture.

Based on historical information from Redondo Beach wells for wells from the western portion of the Torrance oil field, the crude oil potentially produced by the Proposed Project most likely would not contain appreciable quantities of hydrogen sulfide.

Hydrogen Sulfide

The exact level of hydrogen sulfide levels in the gas will not be known until the test wells are developed. There could also be some variation in H_2S levels between the different wells produced as part of Phase 2 or 4. Historical well information for the Redondo Beach wells is sparse as records at that time were more interested in crude oil than gas. However, one of the well records (for well#2) indicated a "rotten odor" from the test gasses, which may indicate the presence of some H_2S. Some of the Redondo Beach wells produced higher hydrogen sulfide gas levels in the later production years, with levels up to 5,000 ppm, but these wells may have become sour due to contamination from injected materials from the surface (according to CSLC and the Applicant). Nearby well sampling data acquired by the Applicant indicates that wells in the Torrance Oil Field within 2.0 miles of the Project Site have historically exhibited H_2S levels of 2.5 to 6 ppm. The Applicant indicates that H_2S levels are anticipated to range up to 6 ppm.

The Stinnett well, located on the current City Maintenance Yard site (and currently abandoned), required weekly maintenance in the 1970s-1980s that involved releasing gas pressure that had built up in the well. The reports of this activity were that a strong smell was associated with

these intentional releases, potentially indicating the presence of hydrogen sulfide (communication with Mr. Flaherty, 5/2014)

Information related to hydrogen sulfide obtained from the California State Lands Commissions indicates the following (CSLC 2013):

- Torrance oil field includes several zones among them the Main zone is the most productive one. From top to bottom; Tar, Ranger, Main(depth; 3500' to 4500', with 1.37% MW of H_2S), and Del Amo
- Inspection of Redondo Beach tank farm for gas streams before and after Scrubber shows the H_2S concentration of (160 – 200) and <80 ppm respectively
- H_2S concentrations for 5 offshore wells before and after treatment recorded as; (1,200 – 5,500) to (0 – 130) ppm respectively
- Well CRB#5 in the Redondo Beach with 1,200 ppm H_2S is the nearest (1/4 mile distance) to the Hermosa Beach border
- Well CRP#3 & 53 distanced 0.6 miles with 4,000 ppm and well S-5 distanced 1.3 mile with 5,500 ppm H_2S
- In June 1994 a water sample from Marble#102, which is located east of the City Maintenance Yard showed no detectable H_2S
- Generally speaking, H_2S concentration increases from north toward south direction

DOGGR indicates in their publication M10 (DOGGR 1997) that the Torrance oilfield has H_2S odor, but with concentrations unknown.

As the design of the facility is to allow gas containing up to 100 ppm of H_2S to be processed, and the Applicant indicates in their application that levels above this are not anticipated, this analysis assumes a peak H_2S level within the produced gas of 100 ppm H_2S. Any gas produced with levels above this would require that the Applicant permanently shut down the high H_2S wells or shut down the high H_2S wells and conduct further CEQA and permit related analysis in order to resume operation of the high H_2S wells.

Odorizing

The gas would be odorized at the Proposed Project odorant station as per requirements of the gas company, most likely with 100 percent tetrahydrothiophene or an equivalent. Tetrahydrothiophene is a liquid at standard conditions (68°F and atmospheric pressure) and has a boiling point of approximately 247°F. It can produce a flammable vapor with explosion limits of 1.1 to 12.3 percent and is, therefore, somewhat volatile. It has a low flash point of approximately 54°F; meaning that, above this temperature, sufficient volatile vapors are produced to create a flash if brought in contact with an ignition source. If spilled, or opened to the atmosphere, the odorant produces a vapor that is approximately three times heavier than air. It is a colorless liquid with a stench and is insoluble in water.

For impacts related to odors, see Section 4.2, Air Quality.

4.8.4.4 Release Scenarios at the Proposed Oil Project Site and Pipeline Route

The approach taken to develop the release scenarios was to group the proposed equipment and operations by operating parameters; equipment that has a similar temperature, pressure and composition were grouped into one set of scenarios. This generally produced a set of release scenarios for each process. Each set of release scenarios contained at least one rupture release and one leak release. This approach encompasses a range of risks by including a less frequent, more severe scenario, and a more frequent, less severe scenario. In some cases, the leak release actually produces a higher risk (i.e., combination of consequence and frequency) than the associated rupture release because leaks occur more frequently than ruptures.

The principal immediate hazards to public health at the Proposed Oil Project Site include:

- Releases associated with drilling activities, resulting in pressured gas releases and subsequent fires or vapor/toxic clouds;
- Releases associated with gas processing of flammable gas resulting in pressured gas releases and subsequent fires or vapor/toxic clouds;
- Releases of odorant causing toxic impacts; and
- Releases of crude oil with subsequent fire causing impacts from thermal exposure to fire.

Table 4.8-10 shows the characteristics of the release scenarios analyzed in this study.

Scenario 1: Releases During Drilling

It is anticipated that the wells drilled would not be pressurized wells once they are drilled and in production for a certain amount of time. When in production (after drilling), the Applicant indicates that wells would utilize down-hole pumping units in order to move the crude oil to the surface. This type of well would not produce a “blowout” type scenario during production that has a sustained release of flammable materials with sufficient volume and duration to produce serious injuries or fatalities offsite.

However, during drilling, and initially during production for a period after the well has been drilled, there may be periods of time and zones of the reservoir where substantial pressures could be encountered, giving rise to the potential for wells that could, if a release occurs, produce pressurized releases that could cause risks to the community.

Historical data from the Redondo Beach wells drilled mostly in the 1950s indicate that, on some wells, there was free flow for up to 15-27 days before pumps had to be installed. While most wells drilled at Redondo exhibited minimal initial flow, based on drillstem test records, free flows from wells during testing did show some wells with very strong gas flows and with surface pressures as high as 800 psi (EB well #5 during a drillstem test). A drillstem test is performed during drilling to test the flow capabilities of the well, produce the reservoir fluids through the drillpipe and allow the well to flow for a time, thereby gathering information on the well. Of the 30 Redondo Beach wells examined, 9 of them had drillstem tests where flows were ranked as "strong" or "very strong" during one of their respective drillstem tests. There were often up to 5 drillstem tests performed for each well with varying results. The drillstem tests generally were run for about an hour. Although the Proposed Project would drill into a different portion of the reservoir which may have different characteristics than the Redondo Beach wells, the Redondo

Beach wells used on this analysis were in the 1950s into an area of the Torrance Field that was only minimally explored previously.

A study prepared by the CSLC (CSLC 1977) examined the potential drainage of oil and gas from lands granted to the City of Hermosa Beach by wells drilled in Redondo Beach in the 1970s. This report estimated that reservoir pressure (the pressure at the bottom of the well hole), based on the bubble point pressure and the gas-to-oil ratios, as high as 2,000 psi could exist, although this was considered unlikely. A more likely scenario would be down hole pressures of 1,000 psi. This range would produce similar surface pressures as the drill stem tests described above. In addition, the Redondo Beach wells did produce gas, with gas-to-oil ratios of 44-4000, indicating that there would be gas produced from the formation. About 9% of the Redondo Wells drilled had GOR below 100, 48% had GOR between 100-600 and 43% had GOR above 600.

Therefore, based on Redondo Beach drillstem testing, for this analysis it was assumed that wells would be pressurized during drilling with up to 1,000 psi pressure and that pressurization would continue for 30 days into the production period. Note that the Applicant has indicated that the wells could be pressurized for as much as 14 days after drilling is completed (Bercha 2013).

This scenario involves rupture of the drilling equipment upstream of the gas gathering system. The release location would be at the drilling site. Failures would be due to piping or valve breaks, vessel failures or high pressure "kicks" and losses of well control that are not controlled by the blowout prevention (BOPE) system. The release was modeled as a rupture with a sustained release of reservoir fluids. Two scenarios were examined: 1) releases with a high GOR above 600 (mostly gas) and 2) releases with a GOR between 100-600, producing shorter, but still offsite, impact distances. The high GOR rupture case assumed a break of 3 inches (leak releases are addressed under scenario 2). The release was modeled at a conservative well head pressure of 1,000 psi. The lower GOR was modeled as a multi-component release with an average GOR of 300. Possible consequences include toxic, flame jets and flammable vapor clouds.

The risks associated with a drilling blowout would be associated with the drilling of either a production or injection well.

Scenario 2: Wellhead Release During Operations

This scenario involves rupture of the gas equipment at the wellheads during operations after drilling. Operational scenarios that could lead to a release would include wellhead or piping failures, value failures, loss of well control (blowout) or releases during well workovers or re-drills. Releases would be associated with only the production wells as the injection wells would just be injecting non-hazardous water. This release was assumed to occur only during the first month of production. The release location would be at the well pad site. Failures would be due to piping, valve breaks, vessel failures, or kicks from high pressure coming up the well-bore. It was modeled as both a rupture and a leak with the entire contents of the well bore being released. The rupture case conservatively assumed a break of 3 inches. The leak case assumed a hole size of 1 inch. The release was modeled at normal operating pressure and temperature. The gas composition was produced gas. Possible consequences include toxic, flame jets and flammable vapor clouds.

Table 4.8-10 Facility Release Scenarios

#	Scenario	Pressure (psig)	Temper-ature (°F)	Composition	Line Size (inches)	Vessels, number	Valves, number	Piping, ft	Volume, cf
1	Drilling blowout	1,000	120	Produced Gas or crude/gas	3-10	0	0	0	continuous
2	Release of Gas at the Well Heads: production	500	120	Produced Gas	3	0	2	80	continuous
3	Release at Gas Plant, low pressure (VRU, VRU Discharge, etc)	25	120	Produced Gas	6	11	44	500	1,876
4	Release at gas plant, mid pressure (1st stage discharge to second stage inlet)	165	120	Produced Gas	4	7	28	255	543
5	Release at gas plant, high pressure (second stage discharge to outlet)	500	120	Natural Gas	3	3	12	255	98
6	Release of Natural Gas from the Gas Pipeline	500	68	Natural Gas	4	0	0	2,640	230
7	Odorant Release	atm	68	Odorant	1	1	4	25	67
8	Crude Oil Release with Fire	atm	68	Crude Oil	4	2	8	-	2900 bbls each
9	Crude Oil Spill	atm	120	Crude	-	-	-	-	2900 bbls each
10	Propane refrigeration system	160	68	Propane	1	2	8	75	50

Source: Applicant data and Bercha 2013 Final

Scenario 3: Release of Production Piping: Low Pressure

This scenario involves rupture of the gas piping between the production well pad and at gas compressors before compression to higher pressures at the gas plant (see Figure 2.18). The release location would be at the gas plant. Failure would be due to piping/vessel ruptures or leaks. It was modeled as both a rupture and a leak with the entire contents of the low pressure gas system being released. The rupture case conservatively assumed a break of 6 inches, or the largest pipeline diameter. The leak case assumed a hole size of 1 inch. The release was modeled at normal operating pressure and temperature, which would be at a relatively low pressure. The gas composition was produced gas. Possible consequences include toxic, flame jets, explosions and flammable vapor clouds.

Scenarios 4: Release of Gas Plant Equipment: Mid Pressure

This scenario involves a rupture or leak of equipment within the gas plant during and after first stage compression to the inlet to second stage compression. Releases would be due to piping failures, vessel failures, valve failures, heat exchanger failures or compressor failures. It was modeled as both a rupture and a leak with the entire contents of the mid pressure gas system (between compression stages) being released. The rupture case conservatively assumed a break of 4 inches, or the largest pipeline diameter. The leak case assumed a hole size of 1 inch. The release was modeled at normal operating pressure and temperature. The gas composition was produced gas. Possible consequences include toxic, flame jets, explosions and flammable vapor clouds.

Scenarios 5: Release of Gas Plant Equipment: High Pressure

This scenario involves a rupture or leak of equipment within the gas plant including and after the second stage compression to the pipeline that transports the gas off site. Releases would be due to piping failures, vessel failures, valve failures, heat exchanger failures or compressor failures. It was modeled as both a rupture and a leak with the entire contents of the high pressure gas system and the pipeline volume being released. The rupture case conservatively assumed a break of 4 inches, or the largest pipeline diameter. The leak case assumed a hole size of 1 inch. The release was modeled at normal operating pressure and temperature. The gas composition was natural gas (without H_2S). Possible consequences include flame jets, explosions and flammable vapor clouds.

Scenario 6: Release of Natural Gas Pipeline and Metering

This scenario involves rupture of the gas pipeline after the natural gas has left the gas plant and is being transported to the SCGC system along valley Drive. It would occur along the pipeline route or at the gas metering location. Failure would be due to piping ruptures or leaks or valve ruptures or leaks. It was modeled as both a rupture and a leak with the entire contents of the gas pipeline being released. The rupture case conservatively assumed a break of 4 inches, or the largest pipeline diameter. The leak case assumed a hole size of 1 inch. The release was modeled at a normal operating pressure and temperature. The gas composition was natural gas. Possible consequences include flame jets and flammable vapor clouds. If the release were to occur back into the facility, there could be sufficient confinement to allow for an explosion.

The pipeline would be equipped with a return pipeline that would be used if the gas is determined not to meet the specifications of The Gas Company. The return pipeline would not normally be used and would be isolated from the normal pipeline by valves.

Scenario 7: Odorant Releases

This scenario includes the odorant facilities located at the gas plant. Releases would be due to equipment or tank failures or releases during tank filling operations if vapor control is not implemented or fails. The release would be a pool spilled onto the ground and vaporizing. Odorant could cause toxic impacts if inhaled at sufficiently high concentrations.

Scenario 8: Crude Oil Release with Fire at Storage

This scenario encompasses the crude oil storage systems at the Facility. The equipment includes the crude oil storage tanks and piping. The scenario assumes a catastrophic loss of the tank contents into the dike area with subsequent ignition and fire. Possible consequences include large crude oil fire and thermal radiation.

Scenario 9: Crude Oil Spill Outside Containment

This scenario involves a crude oil spill that could affect areas outside of the facility site. It encompasses all of the crude oil processing equipment at the site as well as the drainage systems failure. Section 4.3, Biological Resources, addresses potential impacts to biological resources.

This scenario assumes that all tank and piping areas at the Facility would drain to a bermed area. In order for the releases to spill outside of the berm containment, an operator would need to open the drain valve or leave a drain valve open during a subsequent inspection.

Scenario 10: Refrigeration System Releases

This scenario involves a release of the propane refrigerant used in the low temperature separation system. Release could be due to valve, vessel or piping failures. Impacts would be due to flammable vapor clouds or explosions.

Drilling Releases

Releases during drilling activities can occur due to equipment failures, such as ruptured piping or valve structural failures, or can be due to over pressurization of the drilling system due to the lack of well control and control of reservoir pressures, or blowouts. Blowouts release large amounts of pressurized gas and liquid that can ignite, causing a large fire with associated thermal radiation, or the gas can form a vapor cloud, which can cause a vapor cloud explosion if it encounters an ignition source.

Blowouts occur when the drilling encounters an area of sufficient pressure and the drilling muds and cement cannot contain the reservoir fluids, and the reservoir pressure causes oil and gas to flow back up the well to the surface. The flow can occur through the drilling pipe and casing. This is what happened recently in the Gulf of Mexico at the British Petroleum Deepwater Horizon.

The use of blow out prevention equipment (BOPE) can reduce the frequency of uncontrolled blowouts that occur through the drill pipe and casing. These devices are installed on the top of

the well and can close the well hole by shutting a valve or "shearing" off the drilling pipe if the drilling pipe is in the hole. Regulating agencies require the use of BOPE when wells are being drilled or serviced. However, like all equipment, there are times when BOPE do not function properly or the configuration is such that the BOPE does not stop the well flow.

Several agencies compile data on well blowouts and releases. These include the BOEM, the California Department of Conservation, Division of Oil and Gas and the Texas Division of Oil and Gas. The BOEM maintains the most detailed database and accident reports, enabling the frequency of BOPE failures to be defined. Although most of the BOEM data is for offshore environment, it does provide a conservative estimate of BOPE failure and well blowout frequencies.

The BOEM maintains safety reports that are required to be filed for every "loss of well control" incident. The BOEM uses the term "loss of well control" which includes blowouts as well as more minor incidents related to a loss of control of well fluids that do not necessarily result in a release of fluids to the environment. From 1992 to 2005, there were 67 "loss of well control" incidents in the U.S. Outer Continental Shelf (four in the Pacific Outer Continental Shelf and 63 in the Gulf of Mexico).

In order to estimate the frequency of blowouts and subsequent events, the BOEM incident database was examined for all incidents listed as "loss of well control" (MMS 2007). In the BOEM database, each incident has an incident report detailing the events leading up to the incident and the resulting consequences and actions taken. Of the 67 "loss of well control" incidents, approximately 10 percent produced fires, approximately 7 percent were sub-surface blowouts, and in 46 percent of incidents a BOPE stopped the flow. In 33 percent of the releases, the BOPE did not function (due to either equipment failures or the incorrect implementation of procedures) or was not present, resulting in a sustained release for a period of time exceeding 15 minutes, and the release required evacuations from the facility. Table 4.8-11 summarizes the BOEM incident reports. The Applicant has proposed the use of Class III BOPE with blind shear rams, which would allow for the closing off of the well even with drill pipe in the hole, and the use of third-party certification of the blind shear ram capabilities. The third-party verification is a recent requirement for deepwater offshore well drilling as a result of the BP oil spill. Although very little data is available on the reduction in blowout frequency associated with this measure, the Applicant has proposed a reduction fraction of 0.5 in the blowout frequency. Due to the enhanced capabilities of this type of BOPE and the inherent better performance of equipment when its capabilities are verified, this reduction factor was added to the blowout frequency.

Table 4.8-11 also shows the estimated frequency of well blowouts from a number of different studies and agencies. These include data from DOGGR from 1950 to 1990, when more than 100,000 wells were drilled with a total of 140 blowouts. Well blowout rates from 1980 through 1990 are also shown. The table also shows blowout data from the Texas Division of Oil and Gas (Railroad Commission of Texas website); for approximately 250,000 wells drilled from 1990 to 2006, there were 373 well blowouts. The blowout rates for drilling range from 0.33 blowouts to 5.2 blowouts per 1,000 wells drilled. Blowout rates during production are substantially lower than during drilling at approximately 0.14 blowouts per well-year.

For a blowout to occur, the reservoir must be pressurized. During drilling, the drill hole must pass into or through an area that is pressurized. It is unclear at this time the extent to which the reservoir will be pressurized or the drilling will pass through areas that are pressurized. If the wells do not have pressure to allow for sufficient flow of crude oil and gas, then the wells would utilize pumps placed down the well hole to pump up the crude oil. The Applicant is currently proposing the use of this technology. A well that does not have sufficient pressure to free flow cannot have a blowout. It is possible that the reservoir could have some pressure during initial drilling (see above), but this pressure would diminish as the wells went into production over several months.

Table 4.8-11 Blowout and Loss of Well Control Frequencies

Well Blowouts – BOEM Incident Reports Database	
Number of "loss of well control" incidents from 1992 to 2005	67
Fraction occurring during drilling	60%
Fraction occurring during production	9%
Fraction occurring during workovers	15%
Fraction occurring during abandonment, completions, other	16%
Fraction of "loss of well control" incidents producing fires	10%
Fraction of "loss of well control" incidents that were sub-surface	7%
Fraction of "loss of well control" incidents where a BOPE was present	78%
Fraction of "loss of well control" incidents where the BOPE stopped the flow	46%
Fraction of "loss of well control" producing sustained releases	33%
Well Blowouts – Frequency of Blowouts and Release during Drilling, per 1,000 wells drilled	
BOEM loss of well control incident rate with sustained release, 1996 to 2005	1.7
HLID (HLID 1992) frequency of blowouts during drilling	1.6
Texas DOG, well blowouts, 1990 to 2006	1.5
California DOGGR, well blowouts all activities, 1950 to 1990	1.4
California DOGGR, well blowouts during drilling & completion only, 1950 to 1990	0.68
Kern County Drilling, non-thermal wells, 1991-2005	0.53
California DOGGR, well blowouts during drilling only, 1980 to1990	0.33
This EIR (BOEM rate, 30% of wells could produce a blowout, class III BOPE)	***0.26***
Applicant Application	0.10
Well Blowouts – Frequency of Blowouts when not Drilling	
Kern County, workovers, per 1,000 well workovers	0.04
Kern County, production, per 1,000 years	0.01
HLID frequency of blowouts during production, per 1,000 years	0.14
HLID frequency of blowouts during well workovers, per 1,000 well workovers	0.73

Note: MMS has been renamed to BOEM. Sources: HLID 1992, DOGGR 1993, BOEM data online, Texas data online, Kern County (Jordan 2008)

Due to the uncertainty of the levels of pressure that would be encountered in the wells during drilling and production, in this analysis it was assumed that the reservoir or areas the drill hole passes through are pressurized and that blowouts could occur. The rate used for blowouts during drilling was the BOEM (or at the time, the MMS rate) rate for a sustained release, which is the most conservative, and the fraction of wells for this project that are estimated to be pressurized.

The rates used for blowouts during workovers and production were the HLID rates (see Table 4.8-11) (HLID 1992).

4.8.4.5 Frequency Analysis of the Proposed Oil Project Site and Pipelines

Table 4.8-12 shows the failure rates for each of the release scenarios. The sources used in developing the failure rates for this study are listed in the references. The tables located in the risk appendix provide the fault trees and the rationale for each selected failure rate and information on the data sources used. The highest frequency events are associated with leaks. The highest frequency for rupture scenario is associated with well blowouts.

Table 4.8-12 Scenario Failure Rates

Scenario	Annual Odds of a Failure, Once in x Years
Scenario 1 Wellhead Area Rupture during drilling: blowout	323
Scenario 1b Wellhead area leak during drilling	24
Scenario 2 Wellhead Area Rupture during production	604,127
Scenario 2b Wellhead area leak during production -pressurized and non-pressurized wells	576
Scenario 3 Rupture at Gas Plant separators, scrubbers to compressors - low pressure	9,831
Scenario 3b Leak at Gas Plant through inlet scrubbers to compressors - low pressure	1,180
Scenario 4 Rupture at Gas Plant LTS, scrubbers and compressors - mid pressure	12,412
Scenario 4b Leak at Gas Plant LTS, scrubbers and compressors - mid pressure	1,004
Scenario 5 Rupture at Gas Plant compressors 2nd stage - high pressure	23,980
Scenario 5b Leak at Gas Plant compressors 2nd stage - high pressure	1,366
Scenario 6 Rupture at natural gas pipeline along Valley Dr and at meter	9,065
Scenario 6b Leak at natural gas pipeline along Loop Road and at meter	8,418
Scenario 7 Loss of Containment from odorant storage/transfer	14
Scenario 8 Release of Crude Oil and Subsequent Fire	3,660
Scenario 9 Release of Crude Oil Storage/Pumping with subsequent spill outside containment	6,421,148
Scenario 10a Rupture at refrigeration system	28,448
Scenario 10b Leak at refrigeration system	2,478
Combined Facility Gas Rupture during drilling	289
Combined Facility Gas Leak during drilling	21
Combined Facility Gas Rupture: no Drilling	2,695
Combined Facility Gas Leak: no Drilling	207

Source: Failure rate expressed in Odds, or also years between failures. See Risk Appendix

The combined frequency of a release from all the Proposed Project equipment (not including the odorant operations) is estimated in Table 4.8-12 during production when drilling, and during production when not drilling. This includes both rupture and leak releases. Releases during drilling operations are more frequent due to the higher frequency of well blowouts during drilling than during production.

Note that these frequencies do not include the conditional probability that persons may be exposed to the release, that the release reaches public areas, or that meteorological conditions contribute to a large impact zone.

4.8.4.6 Consequence Analysis of the Proposed Oil Project Site and Pipelines

Figure 4.8-5 and the risk appendix show the results of the consequence modeling. The appendix includes the inputs to the modeling, the results of the release rate models, and results of the dispersion, toxic, overpressure, flammable vapor, and thermal radiation modeling. Figure 4.8-5 shows the results of the modeling for both fatality impacts and injuries.

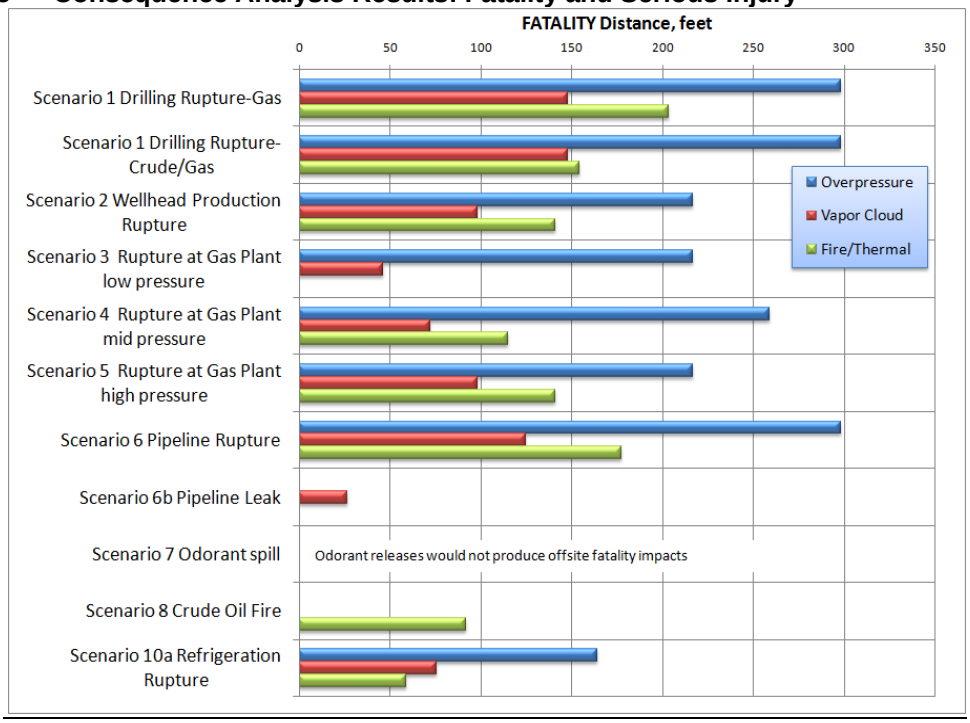
Of all of the scenarios analyzed, a well blowout would create the worst-case in terms of impact distances. This scenario would occur only if the well was pressurized.

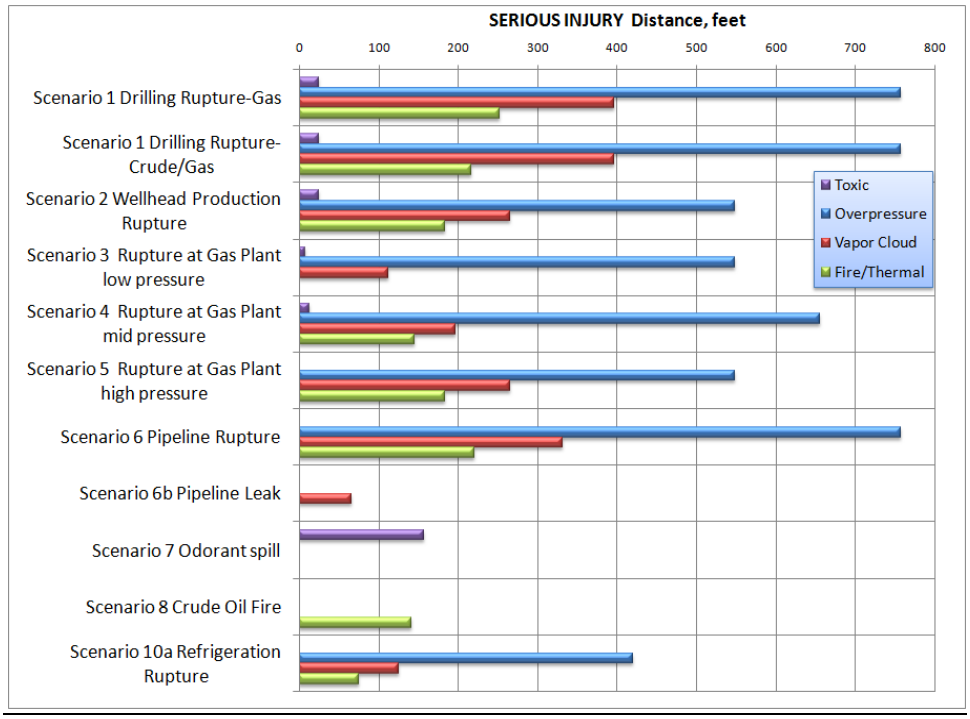
A release from the pipeline could impact nearby residences. However, due to the pipe diameter and relatively short distance, the release would only last less than 5 minutes before pipeline pressure dissipated, assuming that the pipeline rupture location is not also fed by the main gas transmission pipeline along Herondo Street. If the release is also fed by the gas main, the release duration would be longer.

Figure 4.8-6 shows the distances from the Project Site equipment that could produce fatality or serious injury impacts. Note that these impact distances do not represent risk levels, only the areas that could potentially be exposed to these levels of concern. Offsite injuries and fatalities are primarily due to drilling related releases, if the drilling encounters pressurized reservoirs and the thermal impacts due to a crude oil fire. Overpressure zones from flammable gas releases also contribute to the larger zones. Drilling impacted areas are located to the west of the site and crude oil fires are primarily located to the east of the site.

The overpressure curve in Figure 4.8-6 designates the area that could experience some fragment impacts due to explosions (the 0.3 psi line) which could cause some injuries if a person is impacted by fragments. Note that explosions would only be due to propane releases from the refrigeration system or from a gas release that would be associated with some "containment" (within a relatively confined area of the facility, such as within the crude oil containment area between equipment), meteorological conditions appropriate to allow for gathering of the released gas, and a release duration long enough to release enough gas in order to produce an explosion.

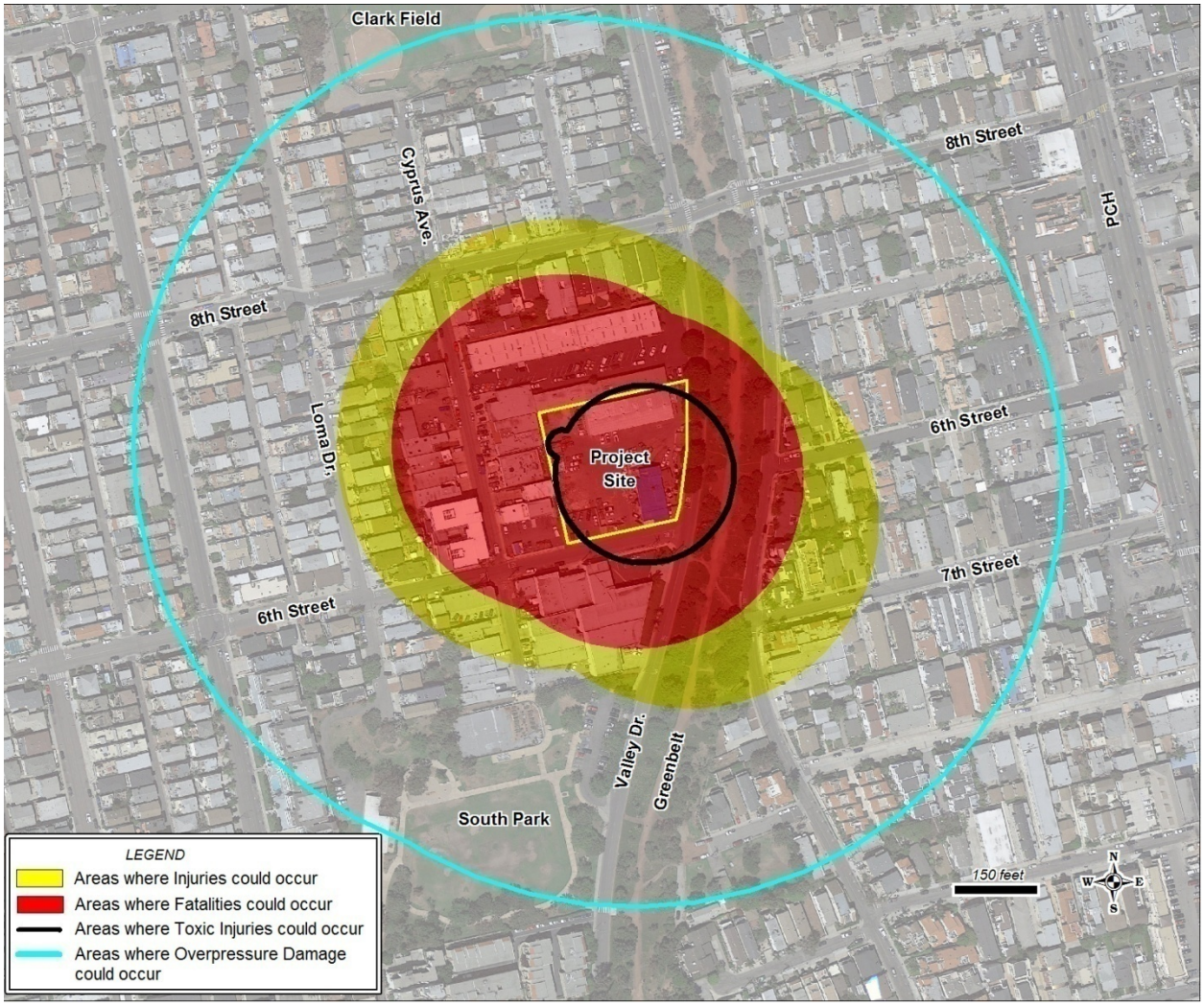
Figure 4.8-5 Consequence Analysis Results: Fatality and Serious Injury





Note: For fatality, Scenario 7, an odorant release, would not produce offsite impacts.

Figure 4.8-6 Areas That Could Be Potentially Exposed



Note that these zones only show areas that could potentially be impacted and do not indicate the frequency that an event could occur.

Hydrogen Sulfide Impacts

The only toxic impacts would be associated with a spill of odorant. This is due to the assumption of a maximum H_2S level of 100 ppm in the produced gas (not in the natural gas that is transported offsite by pipeline). As the fatality and injury levels for H_2S are 100 ppm and 30 ppm respectively (ERPG-3 and ERPG-2), these levels would not be achieved offsite because, when the materials is released, it immediately starts mixing with air,, particularly when it is a pressurized release that would involve jet mixing, and the concentration decreases rapidly. If the concentration within the piping before the release is already close to the fatality or injury levels, the impacts zones would be nominal, at less than 20 feet.

4.8.4.7 Risk Analysis of the Proposed Oil Project Site and Pipelines

The results of the failure rate and consequence analysis were combined to develop risk profile curves. The risk profiles are location dependant, meaning that they provide an assessment of the risk based on the populations estimated to be there today. If the facility were located in an isolated area, the risk profiles would be zero.

The analysis assumed the facilities were operating at their proposed maximum levels and that the populations near the facility were at their current levels with no additional development.

Meteorological data utilized the King Harbor data obtained from the SCAQMD.

Population Data

Population information was estimated for locations within 1,000 feet of the Proposed Project Site. Table 4.8-13 lists these locations and the estimated populations, population densities, and ignition probabilities. The industrial areas around the site, although enclosed, are often equipped with large garage doors that are frequently open to the front, thereby effectively making them more of an outdoor type receptor than one where significant infiltration would be required in order to have impacts. Therefore, these receptors were treated as outdoor receptors. The exception to this is for thermal impacts, where the shielding effect of the building would reduce impacts. Building shielding was assumed to reduce thermal impacts (impacts from a fire) by 50% due the fraction of persons outdoors.

Risk Analysis Results

Figures 4.8-7 and 4.8-8 shows the risk profile curves for the Proposed Project and for the gas pipeline. Impacts associated with the facility assuming that drilled wells would encounter pressurized areas and have the potential for a blowout would present significant risk levels. Risk levels without pressurized wells would be less than significant.

As the majority of the pipeline would be located separate from the facility, the risk profiles are shown separately. Pipeline segments that are close to the facility have been included within the facility risk profiles.

Impacts that could produce a fatality involve higher concentrations of material or higher levels of thermal radiation than the levels that could produce injuries. Therefore, fatality zones are smaller than injury zones; they do not reach as far. The highest risk scenarios for fatality are principally generated by a rupture releases from the drilling operations assuming that there are pressurized wells. As there is some uncertainty associated with that, risk profiles are shown for both the pressurized well scenario and for a scenario where no wells are pressurized. The no pressurized wells scenario also corresponds to the period of time after the Phase 4 drilling when only operations are occurring with no drilling.

Table 4.8-13 Population Information

Location	Population Density (persons per square mile)	Use Factor, hrs per day	Primarily Indoors (I) or Outdoors (O)	Ignition Probability	Notes
6-7th Street residences: east side of greenbelt	28,500	24	I	0.10	Based on Aerial photos
8th Street residences	28,500	24	I	0.10	Based on Aerial photos
Industrial Area 7th and Cyprus	30,000	8	O	0.25	Outdoors based on open business fronts, ventilation systems.
Industrial Area along Cyprus	30,000	8	O	0.25	Based on number of units and estimates.
Other residential areas	28,500	24	I	0.10	
Recreational/Greenbelt	18,700	12	O	0.10	Population estimated based on 50 people per 1,000 meters. Ignition probability due to automobiles.
South Park	5,300	12	O	0.10	Based on park area and parking spaces

Sources: Census data 2010 for Hermosa Beach, Aerial photos for housing unit counts, site visits. Ignition probability of industrial sources based on medium industrial. Houses and automobiles were combined to account for a 0.10 ignition probability.

The FN curves shown in Figures 4.8-7 and 4.8-8 encompass a large number of scenarios, accounting for rupture and leak releases, 16 different wind directions, two groupings of different meteorological conditions, and different potential events (fires, vapor cloud, flame jets, toxic impacts), thereby producing a total of more than 1,000 potential outcomes. This explains the shape that they take on in the figures. FN curves show the frequency of experiencing a scenario (along the Y axis) that produces greater than a given number of serious injuries/fatalities (along the X axis).

Another driver to the risk levels is the scenario of a rupture of the crude oil tank with subsequent ignition and a fire at the facility. The resulting fire would produce levels of thermal radiation that could impact areas offsite and produce injuries or fatalities. This scenario has a high ignition frequency due to the presence of numerous ignition producing equipment within the spill containment area, including the flare, the low temperature separation equipment and the compressors.

Shielding was also included in the risk model. Shielding addresses the reduction in thermal radiation that a receptor might receive due to buildings and walls. Shielding factors of 0.5 (meaning impacts would be reduced by 50%) were included for all receptors in the industrial area due to existing buildings and the proposed Project Site walls. Shielding of 0.1-0.3 (meaning impacts would be reduced by 10-30%) was included for receptors along the Greenbelt due to the project walls.

Impacts from the gas pipeline present risk levels that are less than significant for fatalities, but are close to the significant region partly due to the potential for longer duration events caused by the connection to the gas main. The modeling assumed that a release from the gas pipeline would also drain the gas main it would be connected to, thereby increasing the duration.

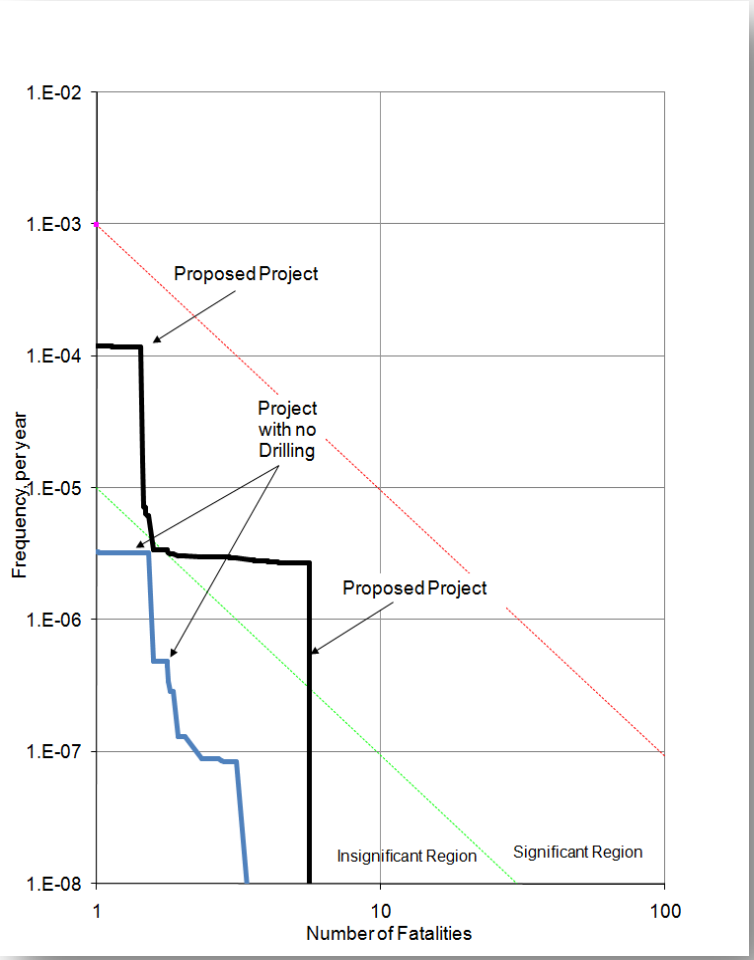
Phase 2 Risks

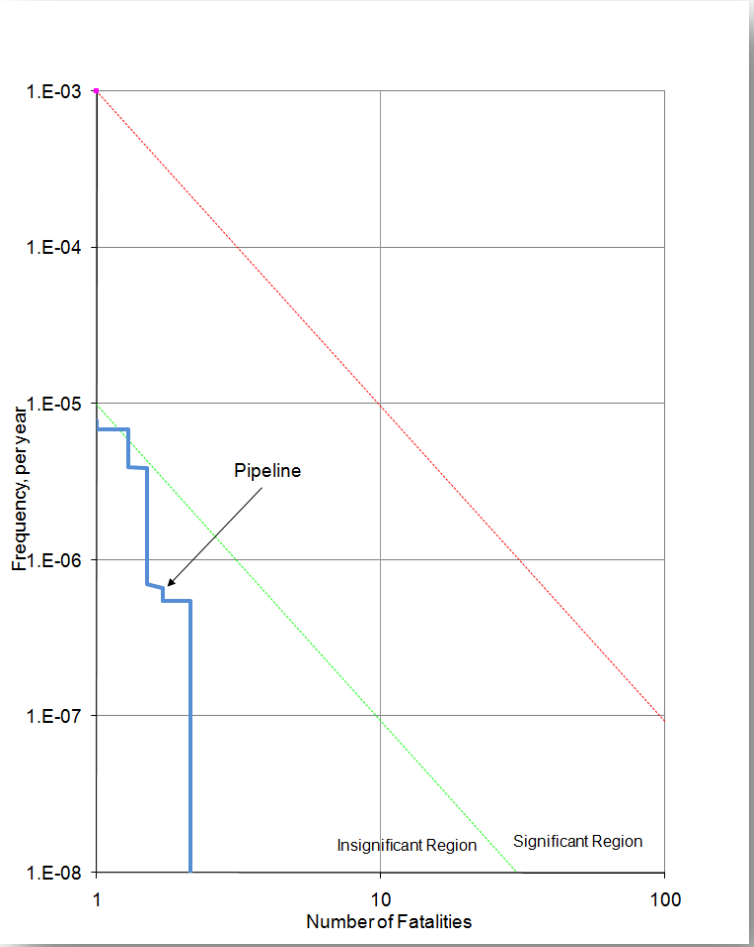
Risk levels associated with Phase 2 would be less than the Phase 4 risk as fewer wells would be drilled (4 as opposed to 12 a year) and less equipment would be located onsite. Risk levels would remain significant during Phase 2 primarily due to the drilling blowout scenario. Risks associated with truck transportation of the crude oil resulting in a potential spill are discussed below under spill risks. Risks due to a crude oil spill from a truck would primarily be environmental as, with the heavier crude oil, ignition probability is quite low.

Comparison to Applicant Studies

The Applicant contracted with Bercha Group to prepare a risk assessment of their Proposed Oil Project (Bercha 2013). Bercha used established standards for assessing risk, in a similar fashion to that assessed in this report. The release frequencies and modeling results were similar to those developed in this EIR. Overall facility release rates for the Bercha study were on the order of once every 2,500 years for a rupture release from the facilities. This is similar to the frequency developed in this report if the frequency of a drilling blowout and a crude oil fire are removed from the analysis. This EIR included those two additional scenarios in order to assess the range of risks that could occur. Crude oil fires and drilling blowouts were assumed in the Bercha Report not to have offsite impacts. The Bercha Study only examined crude oil fires at the well cellar, whereas the EIR examined large spills and resulting impacts from the two 2,900 bbl crude tanks as well, including an increased probability of ignition due to the placement of equipment within the crude oil spill containment berm area. Using data from nearby Redondo wells, gas pressure could be high enough to produce offsite impacts from well blowouts, and these were included in the EIR analysis as well. The resulting FN curves were similar for the operational scenario where no drilling is occurring. Impact distances for flammable vapor clouds were somewhat larger/farther in the Bercha Report due to the use of different models. This report used the publically available SLAB model, which takes dense gas effects in account. Generally, high pressure gas releases involve substantial jet entrainment and temperature changes. This EIR also looked at a lower overpressure scenario than the Bercha Report, 0.3 psi overpressure, to examine the potential for fragment impacts, which produced larger/farther impact zones.

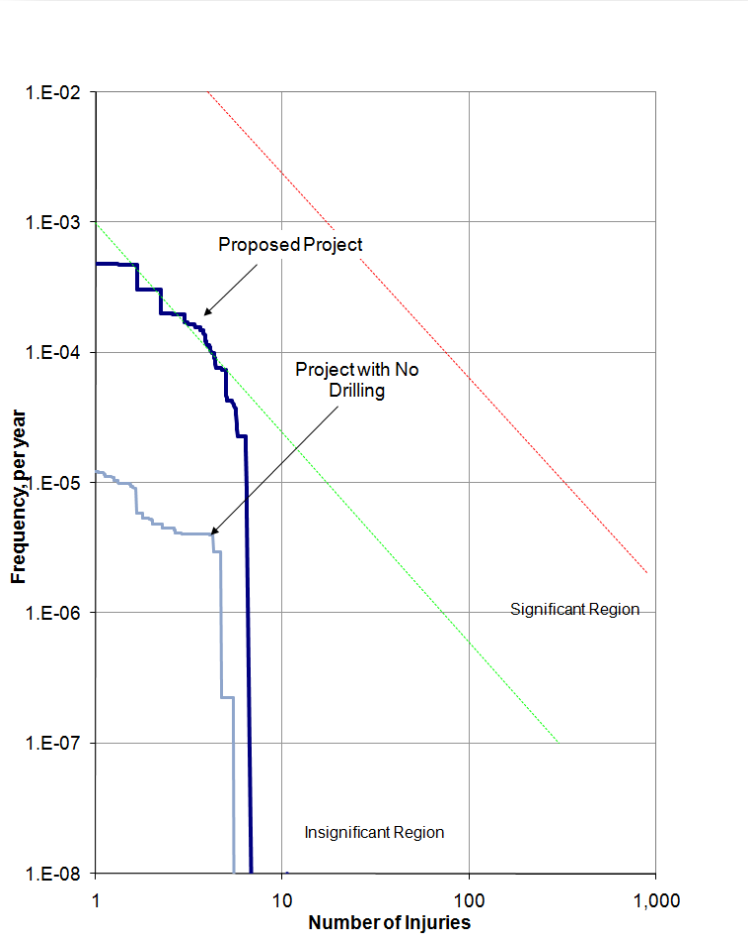
Figure 4.8-7 Risk Profiles for the Fixed Facility and Gas Pipeline: Fatalities

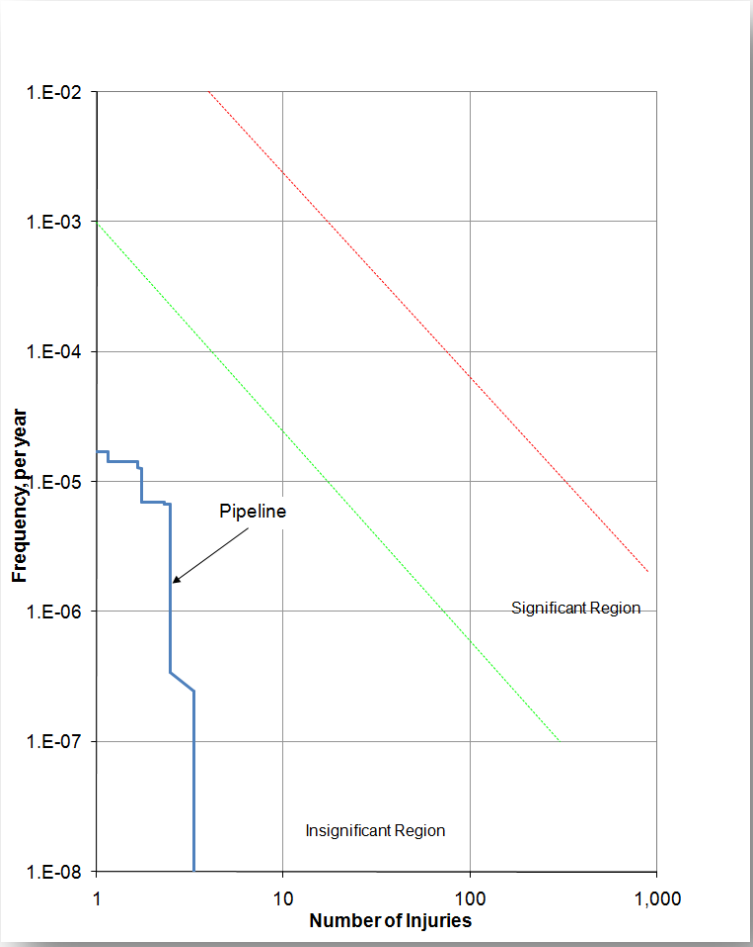




Notes: Fixed facility risk profiles on the left include the pipeline segments located close to the facility.

Figure 4.8-8 Risk Profiles for the Fixed Facility and Pipeline: Injuries





Notes: Fixed facility risk profiles on the left include the pipeline segments located close to the facility.

4.8.4.8 Proposed Project Impacts

The Project's potential to result in significant impacts is discussed below relative to each of the significance thresholds identified in Section 4.8.3, for the Proposed Oil Project and the Proposed City Maintenance Yard.

Near Schools

The proposed drilling and production site, laydown site and proposed parking site are not within a quarter mile of a school. The nearest school is the Hermosa Valley School on Valley Drive, which is 0.5 miles to the north of the site.

There are no schools located within a quarter mile of the gas pipeline, unless the gas pipeline is extended along 190th Street. Along the 190th Street route, there are schools (existing or planned) within a quarter mile of the proposed pipeline alignment options. These include Jefferson Elementary on Flagler in the City of Redondo Beach (0.15 miles), Towers Elementary School on Towers Street also in Redondo Beach (0.15 miles), Valor Christian Academy on Earle St in Redondo Beach (0.12 miles) and North High School on 182nd Street in Redondo Beach (0.25 miles). However, the crude oil pipeline, due to the heavy nature of the crude oil, is not anticipated to produce significant public risk. The gas pipeline could produce risks a distance of 330 feet from the pipeline (0.06 miles), and would therefore not present a significant risk to the nearby schools.

Listed Hazardous Materials Site

None of the sites (drilling and production, laydown site, proposed parking site, oil and gas pipeline alignments, or valve boxes) are included on a list for hazardous materials sites (see discussion in Section 4.8.1.4).

Public Airport or Private Airstrip

None of the sites are within an airport land use plan or within two miles of a public airport or public use airport. The nearest public airport is the Torrance Airport (3.5 miles) and the Los Angeles International Airport (5 miles).

None of the project sites are in the vicinity of a private airstrip.

Impair Emergency Response

This issue is dealt with in Section 4.6, Fire Protection and Emergency Response.

Wildland Fires

The project (all proposed sites) and vicinity is in an urbanized region. There are no wildlands, and thus no risk of wildland fire, in the vicinity.

Hazardous Materials

The Proposed Oil Project could create a significant hazard to the public or the environment through the routine transport and use of a hazardous material or through reasonably foreseeable

upset and accident conditions involving the release of hazardous materials into the environment. The impacts of this are discussed below relative to the significance criteria.

Impact #	Impact Description	Phase	Residual Impact
SR.1	Operational and drilling activities would generate offsite risks that exceed the thresholds.	Operations Phase 2 and Phase 4.	Class I Significant and Unavoidable

As discussed above, the drilling activities could produce offsite risks if they encounter pressurized areas of the reservoirs. Although it is not known at this time what areas, or if any areas, of the drilling will encounter pressure that could produce a blowout, historical data from drilling in Redondo Beach indicates that there is the potential for some of the wells to produce pressure and the potential for a blowout.

The Applicant has proposed features to reduce these risks, including the use of offshore-equivalent-style blow out preventer equipment (BOPE), venting to flare and non-cascading shutdown systems. However, blowout scenarios can still occur due to the potential for a pressurized reservoir and the potential for BOPE failures, and these are difficult to mitigate and would be significant during drilling. Other aspects of the operations contribute to the risk levels, although not in a significant manner, including the equipment arrangements that place spark-producing equipment within the containment, which could possibly be minimized, but as the site is very small, these impacts may not be able to be completely eliminated. However, risk levels during operations without drilling, or if none of the wells are pressurized, would be less than significant. Mitigation measures are listed below in addition to what would be required under the CUP.

Mitigation Measures

SR-1a The Applicant shall cause to be prepared an independent third-party audit, under the direction and supervision of the City, of the gas and crude oil plants and pipelines, once constructed, including the well pads, to ensure compliance with Fire Code, applicable API and NFPA codes, EPA RMP, OSHA PSM, DOGGR and SPCC and emergency response plans requirements. All audit items shall be implemented in a timely fashion, and the audit shall be updated annually, as directed by the City and the Los Angeles County Fire Departments. The final installation of the facilities shall include a seismic assessment, including walkthroughs, of equipment to withstand earthquakes prepared by a registered Structural Engineer in compliance with Local Emergency Planning Committee Region 1 CalARP guidance and the seismic assessment shall be updated, with walkthrough inspections, annually to ensure compliance with the codes and standards at the time of installation.

SR-1b The Applicant shall ensure that the crude oil spill containment areas shall be designed as Class I Division I areas according to NFPA and NEC, or that spark producing equipment (such as the flare) would be isolated from the containment area, in order to reduce the potential for crude oil fires. The refrigeration system shall utilize non-flammable refrigerant.

SR-1c The Applicant shall ensure that all crude-oil truck haulers and a sufficient number of onsite personnel (at least two per shift) are trained in HAZMAT (to the HAZWOPER technician level at least) spill response and that each truck carries a spill response kit.

SR-1d The Applicant shall install automatic valves on the gas pipeline that will automatically shut down under a low pressure scenario at the Processing Facility Area for all pipelines leaving the processing plant, and shall install a backflow prevention device at the main gas pipeline tie-in location, to prevent the release of gas from the main transmission pipeline in the event of a rupture in the gas pipeline. The second, return pipeline shall remain isolated from the main gas pipeline during normal operations.

SR-1e The Applicant shall ensure that warning tape is installed above the pipelines within the pipeline trench to warn third parties that pipelines are located below the warning tape and that the pipelines are capable of utilizing a smartpig.

SR-1f The odorant system shall have its own, smaller containment area around it limiting the spilled pool size to the minimum size attainable, in order to prevent any offsite impacts. Transfer of odorant shall utilize carbon canisters and a canister change-out/maintenance program to ensure that filling of odorant tanks do not cause offsite impacts.

SR-1g The comingled produced gas shall be continuously monitored for hydrogen sulfide. If H_2S levels in the produced gas from any individual well exceeds 100 ppm, then that well shall be shut in and abandoned as per DOGGR requirements. Wells shall be tested when fluids first flow, when the well is placed into production and periodically thereafter in order to ensure that all wells operate below 100 ppm H2S.

Residual Impacts

For the pipeline, the installation of back-flow prevent devices would ensure that a rupture of the pipeline along Valley Drive would produce a release with a short duration. Longer duration releases can substantially contribute to secondary effects, such as structure fires, as well as increasing the injuries and fatalities of persons exposed to jet fires. This measure would ensure that the risks of a pipeline rupture are less than significant with mitigation.

There is uncertainty associated with being able to eliminate spark producing equipment within the crude oil containment. Spacing requirements limit the location of the flare, but if the flare is elevated and surrounding by shrouds/protection, it would minimize the ability of the flare to ignite a spill of crude oil. There would be other spark-producing equipment, such as pumps and compressors, that keeping out of the bermed area would also minimize the chances of igniting a crude oil spill. Incorporating this design safety issue will help reduce the ignition probability given a crude oil spill.

Timely and thorough audits would help to ensure that safety systems are operating as designed and would help to reduce the risk levels. Risk levels during operations without drilling would be less than significant.

Because the blowout scenario cannot be mitigated to a level of insignificant, however, the risks during drilling would remain **significant and unavoidable (Class I)**.

Site Contamination

The Project Site currently contains some contamination from historical activities. The Applicant has proposed a Remedial Action Plan that would excavate the shallower portions of the site and utilize vapor extraction for the deeper, TPH affected areas of the site. The RAP would be implemented during phase 3 of the Proposed Oil Project and be a less than significant impact.

Impact #	Impact Description	Phase	Residual Impact
SR.2	Grading at the site could mobilize soil contamination.	Phase 2	Class II Less Than Significant with Mitigation

During Phase 1 of the Proposed Oil Project, the site would be graded to depths of at least 1-3 feet, and possible more depending on compaction requirements, and areas of lead contaminated soils could be exposed. Modeling of the fugitive dust emissions using AERMOD was conducted based on the grading phase and five years of meteorological data. See section 4.2, Air Quality and Greenhouse Gases for a discussion of modeling parameters. Soil lead contamination levels of greater than 9,500 mg/kg, with the application of water every 3 hours as per mitigation measure AQ-1a, could cause offsite impacts of lead greater than the allowed standards (3 month rolling average). This could cause an exposure of the public to contaminated or hazardous materials during construction activities and would be a significant impact. Note that the Environmental Site Assessment encountered lead levels as high as 9,680 mg/kg, found under the Main Building 15 feet deep. Other lead levels above 1,000 mg/kg were found at depths of 5 to 25 feet.

Mitigation Measures

SR-2 The Applicant shall sample soil during Phase 1 grading to ensure that soil lead contamination levels are below 9,500 mg/kg and that soil contaminated with TPH are below the regulatory guidelines. If soils are encountered above these levels, then those soils shall be removed from the site and transported to a disposal site. This may necessitate implementing the RAP during Phase 1 if substantial amounts of contamination are encountered.

Residual Impacts

By sampling soils and ensuring that soil contamination is not encountered or, if it is, removing those contaminated soils, the impacts would be **less than significant with mitigation (Class II)**.

Spill Risks of the Proposed Oil Project Site and Pipelines

Spills of crude oil from the Project have the potential to impact the environment. Spills could occur from the Project Site facilities, from the crude oil pipeline or from the trucks transporting the crude oil during Phase 2. During Phase 2, crude oil trucks would pass through the City of Hermosa Beach, Manhattan Beach and Redondo Beach along Artesia/Aviation Blvds, and through Torrance, passing by Mira Costa High School in Manhattan Beach. As the crude oil would be heavy and not volatile, it would be difficult to ignite and would not present a significant risk to the public. Therefore, this section analyzes the potential spill frequency and

spill size only. Sections 4.3, Biological Resources, and 4.9, Hydrology and Water Resources, discuss impacts to the environment associated with a spill of crude oil.

The facility and crude oil pipeline would have a number of prevention measures in place, primarily due to regulatory requirements, including berms around processing areas, SCADA systems to monitor for pipeline leaks, pressure sensors, shut-off valves, and pipeline features such as cathodic protection and pipe coating, as well as maintenance activities and internal pipeline inspections.

A crude oil spill from the tanks or equipment at the Project Site would require a subsequent failure of the bermed area or drainage system at the facility in order to impact the environment. The facility is proposed to be designed so that all spills would be captured by berms and the facility drain system and directed into the crude oil/water processing system for disposal down the injection wells or recovered into the crude processing stream. This system could fail with a catastrophic scenario, such as a major earthquake causing failure of the retaining walls. Even this scenario might not produce a spill as the bermed area would be at an elevation below street level. The drain system, as is typical for closed drains, might have (the design details have not been prepared by the Applicant at this time) some overflow type outlet that may flow to the street if a major storm event occurs that floods the capacity of the site sumps or the sump pumps fail or the site might just get full and overflow if electricity is lost and water used to fight a fire overfills the site. This could cause a spill to the environment outside of the facility if a spill were to occur during this type of rain or emergency event. In addition, the drain system, if one is installed, could be left open by mistake during a routine inspection, and not captured by a subsequent inspection, which could allow a subsequent spill to reach the environment. However, the earthquake and drain system failure are all very low frequency events (less than 1 in a million). The scenario where water used for fire fighting overflows the site is addressed in section 4.6, Fire Protection and Emergency Response, and mitigation measure FP-1g, which requires sufficient storage capacity and protection of drain systems.

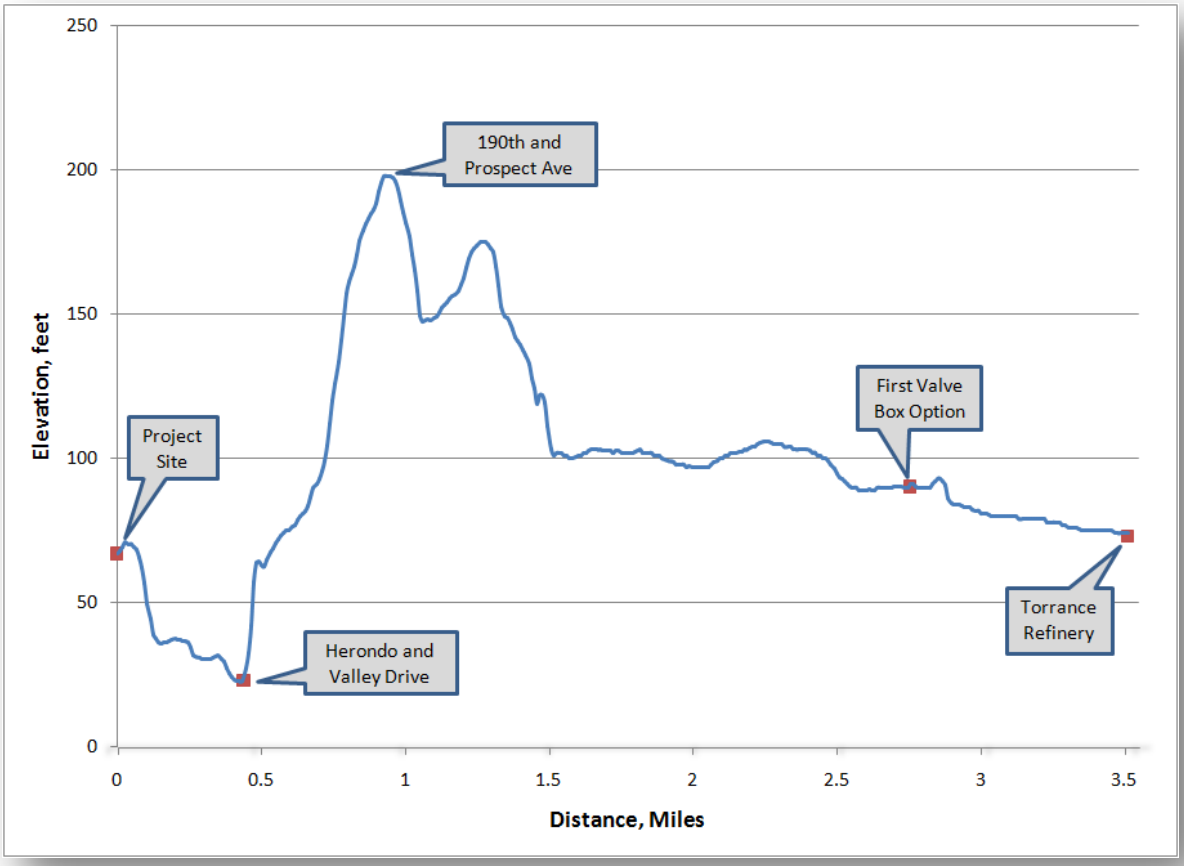
A blowout during drilling at the facility, if the wells are pressurized, could send crude oil up into the air, which could cause impacts outside of the site as well as spill crude oil into the site area. The volumes of crude oil spilled offsite would most likely be a few barrels as most crude oil would affect onsite areas.

Another potential spill scenario would be a subsurface release from the borehole. Incidents of this type have been recorded in the offshore environment, as indicated in Table 4.8-11, with 7% of offshore "loss of well control" incidents involving release from nearby the platform from subsurface. All but one of these incidents occurred during drilling and all of them involved releases coming to the surface within a few hundred feet from the drilling location. Once the wellbore has entered an area that is beneath the seafloor (see Figure 2.8), the wellbore would be more than 1,500-2,000 feet beneath the seafloor. A release from the wellbore to the ocean would have to occur through fissures or other cracks in the geology of the area and would require substantial well pressures as well. Discussions with California State Land Commissions (CSLC 2014) indicate that this scenario would be a very low probability release.

The pipeline transporting crude oil to markets could leak or rupture along its length, allowing crude oil to enter surface streets and storm drain systems, which, depending on the location of

the rupture, would potentially drain to the ocean. The volume of oil from a pipeline spill is a function of two factors: draindown volume and pumping volume. Draindown is the spill of crude oil that is in the pipeline and that drains down to the rupture location and into the environment by the force of gravity. For most spills, not all of the crude oil within the pipeline can drain out of a pipeline rupture due to the terrain profile and air displacement effects. Hence the spill volumes would most likely be smaller than the pipeline volume. Figure 4.8-9 shows the elevation profile of the Proposed Oil Project crude and gas pipelines. The elevation profile is used to estimate the potential draindown volume that could occur at a rupture location. For example, a rupture along the pipeline at the corner of Herondo Street and Valley Drive would be lower in elevation than the Project Site and the peak pipeline elevation at 190th and Prospect Avenue (see elevation profile). Therefore, the crude oil would drain down towards the Herondo Street rupture site from both the Project Site and the pipeline segment between the rupture site and Prospect Avenue. Crude oil in the pipeline on the east side of Prospect Avenue would not drain down to a rupture site at Herondo Street.

Figure 4.8-9 Pipeline Profile



Notes: the elevation profile are based on Digital Elevation Model (DEM) from the USGS and the Applicant submitted pipeline route.

Pumping volumes are due to a spill of crude oil through the rupture that is due to the action of continuing to pump the crude oil after the rupture occurs. For a large rupture, with a spill diameter equal to the pipeline diameter that could occur due to a large earthquake or third party impact, pressure sensors at the facility would most likely (depending on the release characteristics, rate and location) detect the immediate pressure drop and sound alarms, allowing for a shut-down of the pumping within 5 minutes (note that draindown would still occur). For a spill that occurs more slowly, through a smaller hole, where the pressure drop is not substantial enough to be picked up at the facility, leak detection would rely on the SCADA system balancing (5% of flow in 15 minutes, for example, see Section 2.0, Project Description). A leak of as small as 175 gallons over 15 minutes could be detected by the SCADA system in 15 minutes. This assumes that everything operates correctly and that operators respond accordingly. Some historical spills, such as the Platform Irene spill, were exacerbated by the operator re-starting the pumps, thereby increasing the pumping volume by 60 minutes. Therefore a worst case pumping time of 60 minute has been assumed.

Table 4.8-14 shows the potential spill volumes at different locations along the pipeline. The Herondo Street and Valley Drive location would be the worst case spill volume along the pipeline for spills closer to the ocean. A crude oil rupture at the intersection of Herondo Street and Valley Drive could enter storm drains that flow about 1500 feet to an ocean outfall on the beach (see Figure 4.8-2 and 4.8-3). Spills on the east side of Prospect Avenue would still impact the environment and storm drains, but most likely would not impact the ocean unless there are substantial storm flows occurring through the storm drain system.

Sections 4.3, Biological Resources, and 4.9, Hydrology and Water Resources, discuss impacts associated with a spill of crude oil on hydrological and biological resources.

Table 4.8-14 Potential Proposed Oil Project Pipeline Spill Volumes

Leak Location	Drain Down Volume, gallons	Normal Shutdown Pumping Volume, gallons	Normal Shutdown Spill Volume, gallons	Worst Case Pumping Volume , gallons	Worst Case Spill Volume , gallons
Herondo and Valley Drive	2,332	1,167	3,499	14,000	16,332
Between Prospect and Flagler Ln.	810	1,167	1,977	14,000	14,810
At Exxon Mobil Refinery	2,799	1,167	3,966	14,000	16,799

Note that this depicts the design capacity of the pipeline, at 8,000 bpd. The worst case shutdown time is 60 minutes. Normal shutdown time is 5 minutes.

Since crude oil would be temporarily transported by truck during Phase 2, crude oil could spill if an accident, such as a rollover, caused a rupture of the truck tank. A spill of crude oil would produce environmental impacts if the spill drained into culverts or drainage areas that lead to creeks, the ocean or other sensitive areas (see Sections 4.3, Biological Resources, and 4.9, Hydrology and Water Resources). Truck spill volumes would be limited to about 6,700 gallons, which would be the capacity of a crude oil truck. If an accident were to occur with a resulting spill along Valley Drive or along Herondo Street, and the spill were to enter into the storm drain system, the crude oil could reach the ocean.

Because the crude is relatively heavy, spills of crude oil would be odiferous, but generally would not present a serious health impact to area residences. There is a possibility that the spilled crude oil could ignite and burn, similar to the possibility that the truck diesel fuel could spill, 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. Recent events associated with unit train accidents have highlighted the dangers of very light crude oil, which would have substantial vapors that could be released if the crude oil is spilled; however, this crude oil would be heavy with minimal vapor releases.

DOT nationwide data on 3,147 crude oil pipeline spills indicates that, since 1986, four deaths have occurred related to crude oil pipeline spills. Two of these were employee accidents related to maintenance activities and the other two were 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 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.

A spill near Herondo Street and Valley Drive, whether from a truck or the pipeline, would most likely be directed into the storm drain system. The storm drain system, from that point, drains about 1,500 feet through storm drain piping into an ocean discharge (See Figure 4.8-4). This particular discharge is a long cement "tunnel" that, during rains, allows storm water to drain under the beach into the surf without disturbing too much of the beach sand area (the discharge is located about 150 feet from the surf line, depending on tide). During dry periods, sand builds up around the mouth of the discharge making a sort of containment area that might trap a crude oil spill depending on the amount of sand build-up and the standing water inside the discharge tunnel. However, during rains, crude oil would readily flow with the rain water through the storm drains, through the discharge "tunnel" to the ocean.

A few examples of area oil spills involving pipelines and storm drains or creeks:

- Nearly 805 gallons of crude oil bubbled up from a break in an underground Crimson pipeline. Firefighters built sand berms around the spill to keep it from spreading. No oil reached sensitive areas (Huntington Beach, July 4th, 2011).
- A minor landslide caused a pipeline break in the oil fields near Faria Beach, about 10 miles northwest of Ventura. Officials said about 55 gallons of oil flowed down the ravine and made its way to the beach sand (Ventura March 8, 2011).
- About a thousand gallons of crude oil spilled onto the street near the Breitburn Operating Company. Firefighters said they stopped the oil from entering a storm drain (Los Angeles, October 28, 2010);
- 672 gallons of crude oil spilled into a Huntington Beach flood-control channel that drains to wetlands and the Pacific Ocean. The oil traveled 1.8 miles downstream, but it did not reach wetlands or the ocean (Huntington Beach, January 22, 2010).
- A spill occurred from a Crimson Pipeline during a major storm. The State Department of Fish and Game and the Los Angeles Watershed Protection Division recovered more than 1,000 gallons of oil. The leak was traced to a gash in the protective casing around the

pipeline. The leak reportedly seeped from the Wilmington pipeline into the Los Angeles storm drain system and eventually into the ocean (Wilmington Dec 10, 2010); and

- Thousands of gallons of diluted crude oil/water spilled from a broken pipeline into Ballona Creek near La Cienega Boulevard, near the Los Angeles-Culver City border for at least four hours. Emergency crews apparently were able to stop the flow before it polluted the ocean. The spill extended three to four miles long (Los Angeles, Oct 9, 1999).

Comprehensive Environmental Response, Compensations, and Liability Act (CERCLA), Emergency Planning and Community Right-to-Know Act (EPCRA) and California law require responsible parties to report hazardous material releases. Data from 1993-2012 is available online (CalOES 2014). E&B Natural Resources has reported 12 spills at facilities in Santa Barbara County, Kern County and San Luis Obispo County between 2007-2012. The largest spill was 2,730 gallons of crude oil. The most common spills were from pipeline breaks and tank overflows. All spills were contained.

About nine days a year in Los Angeles (for Torrance) have precipitation over 0.50 inches (Western Regional Climate Center data for 1937 - 2012). A day with 0.50 inches would be sufficient to create substantial storm drain flows.

Spill Frequencies of the Proposed Oil Project Site and Pipelines

As a pipeline system is a fixed entity, 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. 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 bbl 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% of spills, with spills caused by corrosion ranking second, with an estimated 24% 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. About 56% of pipeline mileage is crude oil and the remaining mileage being refined product or highly volatile liquids. A breakdown of the DOT database for California demonstrates that, for the years since 2010, 2002-2010 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), analyzed leak information for the 7,800 miles (at that time) 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 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. Although the CSFM database is older, the results are similar to the DOT rate for crude oil pipelines.

Because seismic activity is a concern in California, seismically-induced ruptures were examined in the CSFM database. Three of the 507 pipeline spills reported in the CSFM report for the 1981 to 1990 study period were related to seismic activity. Based on the total length of pipelines in the State (72,303 mile-years), and the number of spills (three) observed during this 10-year period, the base rate for seismically induced spills would be 0.004 spills per 1,000 mile years. This number has been included in the rupture rates.

For the Proposed Oil Project pipeline with newer pipe (average age over the life of the Project of 20 years), elevated temperature, pipe type and coating type of average, the failure rate utilized in this EIR is the 5.27 spills per 1,000 mile years calculated from the CSFM database as it is considered to be the most conservative.

Based on the entire pipeline distance, the estimated rate of ruptures and leaks for the entire pipeline length would be once every 297 years for a rupture and once every 65 years for a leak where leaks are defined as less than 50 bbls. Spills due to ruptures and leaks in the Herondo Street area, nearer to the ocean, are estimated to occur once every 1,109 and 244 years, respectively.

In order for a spill to reach the ocean, it would have to flow into the storm drains, down the storm drains to the ocean outfall and into the ocean. This would only be a concern in the pipeline area along Valley Drive and Herondo Street/190th west of Prospect Avenue. Drainages east of Prospect Avenue would have to flow east and south to the Los Angeles Harbor to get to the ocean, a distance of 8 miles. When there is no flow in the storm drains (they are dry), if a sufficient amount of oil is spilled, most likely it would cool and, as the oil would be heavy and viscous, most likely would not reach the ocean. Some might get diverted by the low flow diverter system along Herondo Street and into the sewer system. If it is raining, however, the oil would be rapidly carried through the storm drain system to the ocean. As discussed above, the ocean outfall can be plugged by sand buildup on the beach. This level of plugging is dependent on the tide and sand movement history, but generally, if there is flow, the sand plug would be either flushed out or removed by City staff. The exact amount of flow associated with any storm event is a function of a number of conditions, including the saturation levels of the ground, recent storm history, etc. City Staff indicate that storm drain flow would be sufficient to produce flow with more than 0.10 up to a 0.50 rain event, depending on conditions (conversation with Mr. Flaherty). Historical rain data from Torrance was used, along with the failure frequencies, to produce a table of probabilities for pipeline failures along the Valley Drive/Herondo Street occurring during a given rain event. Table 4.8-15 shows the results of the analysis.

Table 4.8-15 Pipeline Spill Frequencies and Rain Events: Herondo Area Only

		Rain Event, inches per 24 hours			
		0.01	0.10	0.50	1.00
Annual Average Number of Days -->	**Anytime**	**34**	**22**	**9**	**4**
Annual Probability	-	-	-	-	-
Rupture	$9.0X10^{-4}$	$8.4X10^{-5}$	$5.4X10^{-5}$	$2.2X10^{-5}$	$9.9X10^{-6}$
Leak	$4.1X10^{-3}$	$3.8X10^{-4}$	$2.5X10^{-4}$	$1.0X10^{-4}$	$4.5X10^{-5}$
Project Life Probability	-	-	-	-	-
Rupture	3.1%	0.29%	0.19%	0.08%	0.03%
Leak	12.4%	1.32%	0.86%	0.35%	0.16%
Combined Probability (leaks and ruptures)	14.7%	1.61%	1.05%	0.43%	0.19%

Notes: Rain data from Western Regional Climate Data webpage http://www.wrcc.dri.edu/, Station:(048973) Torrance, period of 1932-2012.

These rates can also be expressed in terms of probability using probability theory and statistics. The Poisson distribution is a discrete probability distribution that expresses the probability of a number of events occurring in a fixed period of time if these events occur with a known average rate, and are independent of the time since the last event. The distribution was postulated by Siméon-Denis Poisson (1781–1840). The probability that there are exactly k occurrences is given below.

$$f(k;\lambda) = \frac{e^{-\lambda}\lambda^k}{k!},$$

where e is the base of the natural logarithm (e = 2.71828...), k is the number of occurrences and λ is a positive real number, equal to the expected number of occurrences that occur during the given interval.

Utilizing the Poisson equation, the probability that there would be any sized spill along any point of the pipeline over the 35 year life of the Project would be 34%. The probability of any sized spill in the Herondo Street area, nearer to the ocean, is estimated to be 15%. The probability of any spill occurring during a 0.50 inch storm event in the Herondo Street area would be 0.4% over the life of the Project. The significance criteria do not specify the frequency at which an upset scenario producing a spill creates a "significant" hazard to the environment. However, the impacts to the environment are discussed in Sections 4.3, Biological Resources, and 4.9, Hydrology and Water Resources.

Risks associated with the truck transportation of heavy and medium crude oil cargo would be a result of spills affecting the environment. These risks are defined by assessing the accident rate and the conditional probability of a spill. Studies related to transportation risk include those prepared by the National Highway Transportation Safety Board (NHTSB), USDOT, CHP, those published in the Journal of Loss Prevention and the Journal of Transportation Engineering, and European studies published in the Journal of Hazardous Materials. These accident rates range from 0.32 per million miles (for haz-mat only trucks) to 2.5 per million miles (from the DOE,

bulk liquids). Recent data from the DOT (Truck Facts 2011) indicate an overall truck accident rate of 1.07 accidents per million miles (producing fatalities, injuries or property damage), with about 13% of trucks carrying flammable liquids releasing their cargo during the accident. According to Truck Facts, about 1/3 of these accidents occurred on arterial or collector sized streets. About 2.5% of truck accidents involved rollovers, which would be the scenario most likely to produce a complete loss of contents.

If an accident occurs, the probability of a release also occurring is the conditional probability. Conditional probabilities identify percentages (or fraction) of time when a spill might occur after an accident. Conditional probabilities of a release, given an accident occurs, range from 35% (FMCSA, non-pressurized liquid) to 2.6% (SWITRS, all tank trucks).

Based on the period of time which trucks would be transporting crude oil during Phase 2, the frequency of any spill from a truck would be once every 11,000 years (or a 0.005% probability during Phase 2) and assuming a rollover produces a complete loss of contents, the rate for a complete loss of contents would be once every 62,000 years (or a 0.001% probability during Phase 2). See Sections 4.3, Biological Resources, and 4.9, Hydrology and Water Resources for impacts.

Valve Box Options

The Proposed Project includes three different options for the location of the valve box for the tie-in to the crude oil system. Risk impacts could be realized if releases occurred from components, causing localized impacts. Therefore, the greater separation distance the better from populated areas. The valve box options 2 and 4 provide the best separation distances.

Pipeline Route Options

The Proposed Project includes three different options for the pipeline route for tie-in to the crude oil system. Scenario 1, Scenario 2 and Scenario 3, would all present the same risks of upset and none is preferable.

4.8.4.9 Proposed City Maintenance Yard Project Risks

The Proposed City Maintenance Yard site (for temporary and permanent facilities) is 0.18 miles from the Hermosa Valley School on Valley Drive. The Proposed City Maintenance Yard site would not handle hazardous materials that could impact areas offsite and would therefore not present a significant risk to the Hermosa Valley School.

The Proposed City Maintenance Yard is not included on a list for hazardous materials sites, is not within an airport land use plan or within two miles of a public airport or public use airport or is in the vicinity of a private airstrip.

The Project and vicinity is in an urbanized region. There are no wildlands, and thus no risk of wildland fire, in the vicinity.

Site contamination at the existing City Maintenance Yard would be cleaned up as part of construction activities and would therefore not cause a significant impact.

The Proposed City Maintenance Yard Project would not store quantities of hazardous materials that could cause impact to the public offsite and would therefore be less than significant.

The potential for spills from the Proposed City Maintenance Yard would be the same as the current City Maintenance Yard, which would be nominal due to the small quantities of consumer level paints and solvents that would be stored onsite.

4.8.5 Other Issue Area Mitigation Measure Impacts

Mitigation measure AE-1b in Section 4.1, Aesthetics and Visual Resources, would provide for a permanent wall around the Project Site. A permanent wall would allow for additional protection in the event of an overpressure scenario as most of the overpressure energy of the explosion would be directed upwards. Mitigation measures in Section 4.6, Fire Protection and Emergency Response, related to spacing, ignition sources and fire foam requirements (FP-1a and FP-2b) would reduce the frequency of crude oil fires.

None of the mitigation measures from other issues areas would increase the risk levels at the Proposed Oil Project Site, Proposed City Maintenance Yard Project Site or along the Pipeline routes. Therefore, the mitigation measures would not result in additional impacts, and additional analysis or mitigation is not required.

4.8.6 Cumulative Impacts and Mitigation Measures

Impacts of cumulative projects would occur if there were an increase in the frequency or volume of oil spills into the same environment as the Proposed Project, an increase the public safety risks to the same populations as the Proposed Project, or an increase in the risks due to an increase in the receptor populations within the Proposed Project impact zones. None of the cumulative projects would affect the same populations or increase the number of populations that could be exposed to the Proposed Project scenarios. A fire or explosion at the AES site, would not impact the same areas as a release from the Project Site. Therefore, there are no cumulative significant impacts.

4.8.7 Mitigation Monitoring Plan

Proposed Oil Project and Pipeline Mitigation Measures				
Mitigation Measure	Requirements	Compliance Verification		
		Method	Timing	Responsible Party
SR-1a	The Applicant shall cause to be prepared an independent third-party audit, under the direction and supervision of the City, of the gas and crude oil plants and pipelines, once constructed, including the well pads, to ensure compliance with Fire Code, applicable API and NFPA codes, EPA RMP, OSHA PSM, DOGGR and SPCC and emergency response plans requirements. All audit items shall be implemented in a timely fashion, and the audit shall be updated annually, as directed by the City and the Los Angeles County Fire Departments. The final installation of the facilities shall include a seismic assessment, including walkthroughs, of equipment to withstand earthquakes prepared by a registered Structural Engineer in compliance with Local Emergency Planning Committee Region 1 CalARP guidance and the seismic assessment shall be updated, with walkthrough inspections, annually to ensure compliance with the codes and standards at the time of installation.	Review of audit reports	Before Phase 4 operations and annually thereafter	LACFD HBFD Cities of Redondo Beach and Torrance
SR-1b	The Applicant shall ensure that the crude oil spill containment areas shall be designed as Class I Division I areas according to NFPA and NEC, or that spark producing equipment (such as the flare) would be isolated from the containment area, in order to reduce the potential for crude oil fires. The refrigeration system shall utilize non-flammable refrigerant.	Review of design documents	Before Phase 3 construction	City of Hermosa Beach HBFD Cities of Redondo Beach and Torrance
SR-1c	The Applicant shall ensure that all crude-oil truck haulers and a sufficient number of onsite personnel (at least two per shift) are trained in HAZMAT (to the HAZWOPER technician level at least) spill response and that each truck carries a spill response kit.	Site inspections, review of contracts	Before Phase 2 drilling	City of Hermosa Beach HBFD Cities of Redondo Beach and Torrance

Proposed Oil Project and Pipeline Mitigation Measures				
Mitigation Measure	Requirements	Compliance Verification		
		Method	Timing	Responsible Party
SR-1d	The Applicant shall install automatic valves on the gas pipeline that will automatically shut down under a low pressure scenario at the Processing Facility Area for all pipelines leaving the processing plant, and shall install a backflow prevention device at the main gas pipeline tie-in location, to prevent the release of gas from the main transmission pipeline in the event of a rupture in the gas pipeline. The second, return pipeline shall remain isolated from the main gas pipeline during normal operations.	Review of design documents	Before Phase 3 construction	City of Hermosa Beach HBFD Cities of Redondo Beach and Torrance
SR-1e	The Applicant shall ensure that warning tape is installed above the pipelines within the pipeline trench to warn third parties that pipelines are located below the warning tape and that the pipelines are capable of utilizing a smartpig.	Review of design documents	Before Phase 3 construction	City of Hermosa Beach HBFD Cities of Redondo Beach and Torrance
SR-1f	The odorant system shall have its own, smaller containment area around it limiting the spilled pool size to the minimum size attainable, in order to prevent any offsite impacts. Transfer of odorant shall utilize carbon canisters and a canister change-out/maintenance program to ensure that filling of odorant tanks do not cause offsite impacts.	Review of design documents	Before Phase 3 construction	City of Hermosa Beach HBFD
SR-1g	The comingled produced gas shall be continuously monitored for hydrogen sulfide. If H_2S levels in the produced gas from any individual well exceeds 100 ppm, then that well shall be shut in and abandoned as per DOGGR requirements. Wells shall be tested when fluids first flow, when the well is placed into production and periodically thereafter in order to ensure that all wells operate below 100 ppm H2S.	Review of design documents and in-field inspections	Before Phase 2 drilling	City of Hermosa Beach HBFD Cities of Redondo Beach and Torrance

Proposed Oil Project and Pipeline Mitigation Measures				
Mitigation Measure	Requirements	Compliance Verification		
		Method	Timing	Responsible Party
SR-2	The Applicant shall sample soil during Phase 1 grading to ensure that soil lead contamination levels are below 9,500 mg/kg and that soil contaminated with TPH are below the regulatory guidelines. If soils are encountered above these levels, then those soils shall be removed from the site and transported to a disposal site. This may necessitate implementing the RAP during Phase 1 if substantial amounts of contamination are encountered.	Review of design documents and in-field inspections	Phase 1	City of Hermosa Beach