EAST CAT CANYON

OIL FIELD REDEVELOPMENT PROJECT

QUANTITATIVE RISK ASSESSMENT UPDATE

MARCH 2016

PREPARED FOR:

AERA ENERGY LLC

BAKERSFIELD, CALIFORNIA

PREPARED BY:

DIXON RISK CONSULTING

SOLVANG, CALIFORNIA

Table of Contents

Table of Contents (continued)

List of Tables

List of Figures

1. INTRODUCTION

1.1 Background

The East Cat Canyon Oilfield Redevelopment Project (Project) is located approximately 10 miles southeast of the Santa Maria in northern Santa Barbara County. Aera Energy LLC (Aera) proposes to re-establish oil production there within the designated Cat Canyon Oil Field. The main property entrance is located at 6516 Cat Canyon Road.

Based on the proposed construction and operational activities, the Project is subject to discretionary land-use permits and environmental review by the County of Santa Barbara. Aera has requested that Dixon Risk Consulting (DRC) conduct a Quantitative Risk Assessment (QRA) to assess the significance of risks to the public associated with the proposed oil production activities.

1.2 Scope of Work

The QRA assesses risks to the public from the proposed crude oil and gas processing facilities, the on-site natural gas pipeline, and the on-site portion of loading and shipment of light crude oil and on-site produced heavy oil using tanker trucks. The risks associated with offsite portions of the natural gas pipeline and tanker truck transportation will be addressed by a separate transportation QRA study.

The potentially acutely hazardous risks associated with the following operational activities at the Project Site are:

- Fire, explosion and spill at the Central Processing Facility (CPF) located east of Cat Canyon Road,
- Fire, explosions, and spill from proposed offloading of light crude oil and loading of heavy crude oil using tanker trucks, within the Project Site,
- Fire and explosions from the natural gas pipeline within Aera property supplying fuel to the project site,
- Hydrogen sulfide release from petroleum production and processing facilities, and
- Emissions from the emergency flare.

The significance of risk to the public associated with exposure to acutely hazardous materials has been assessed. The thresholds for acceptable risk of fatality or serious injury to the public are as defined by the Santa Barbara County (SBC) risk criteria. The County has published thresholds of acceptability in order to determine the significance of impacts in a consistent manner.

1.3 Quantitative Risk Assessment Methodology

Quantitative Risk Assessment is an established methodology to quantify the risk of a potential event, by estimating the likelihood and consequence of the event. The risk of fatality or serious injury to the public has been assessed using the following steps:

- Identify potential release scenarios.
- Quantify the likelihood of these scenarios.
- Determine the consequences and potential impact on the public.
- Combine the likelihood and consequences to calculate the societal risk, presented as a risk profile.
- Assess the risk of significant injury/fatality against the SBC risk profile criteria.
- Develop potential mitigation measures to reduce the public risk profile to insignificant, if necessary.

QRA provides an estimate of the risks, which tends to err on the side of conservatism. The approach was to make reasonable assumptions on the hazards, likelihood of failure and potential impact on the public. In the process of QRA, numerous assumptions must be made, based on best available information. Where appropriate, sources of these assumptions, estimates and reasoning have been described.

2. East Cat Canyon Oil Field Description

2.1 Facility Overview

The Project site is located approximately 10 miles southeast of Santa Maria, within an existing oil and gas production area. The facility is located in a rural area, with neighboring oil and gas production facilities, grazing land. The Project site and surrounding properties are agriculture zoned with minimum parcel sizes of 10, 40 and 100 acres.

Figure 2.1 shows the location of the proposed Project site. The surrounding land use is as follows,

North	Grazing, Oil Production, AG-I-10, AC-40, AG-II-100
East	Grazing, AG-I-10, AC-40, AG-II-100
South	Grazing, Oil Production, AC-40, AG-II-100
West	Grazing, Oil Production, AC-40, AG-II-100

The Project involves the drilling and production of crude oil at well depths of about 3,000 ft, using the enhanced oil recovery method of steam injection. An expected total of 141 production wells and 113 continuous steam injection wells will be utilized. In addition, there will be 7 steam generators, a processing plant, gathering and distribution pipelines, and related ancillary equipment. Well drilling will occur from Year 1 through Year 19 of the project. The majority of the construction of related infrastructure will occur in two phases of development.

The oil produced from the site is expected to have an average gravity of about 9 API which is very viscous. Lighter crude oil will be used to blend with the heavy oil to reduce the viscosity for separation and transportation.

Production Facilities

The wells will yield heavy crude oil, produced water and small quantities of gas. Steam injection into the reservoir will be used to heat the oil and reduce its viscosity. Reservoir fluids will be lifted to the surface with positive displacement, rod-pump systems.

When the field is at full capacity (currently forecasted in 2032), there will be an expected total of 141 production wells producing the following estimated quantities:

Produced Oil: 10,000 BOPD (9.0 API initial to 7.6 API at full production)
Produced Water: 36,000 BWPD
Produced Gas: 1,000 MSCFD (5 to 10% H_2S)

Well production will be monitored using a Supervisory Control and Data Acquisition (SCADA) system. Oil, water and gas will be recovered from one casing pipe, and this combined production will flow at about 250 psig and 400^{o}F via gathering lines to the Group Station (GS) for separation. This will be located in the central area of the site.

Two parallel group production separators will be installed, the second one being added for phase 2 production. At the group separators, produced gas and vapor will be separated from the liquids at approximately 25 psig and 260°F.

Production liquids from each group separator will flow through separate transfer lines to parallel oil treating trains at the Central Processing Facility. Production gas will be combined and transferred to the Produced Gas Treatment Plant (PGTP), located next to the Group Station.

Imported light crude oil will be blended into the produced fluids at the Oil Treating Plant. Produced water and sand will then be separated from the produced oil. Blended produced oil will be stored in two 10,000 barrel tanks prior to transportation off-site by truck.

Steam Generation

The produced water will be treated at the CPF then used as feed for the steam generators. Seven steam generators will be located in a central area, at the Steam Generator Site (SGS). Six generators will burn natural gas, and one steam generator will burn a mix of natural gas and treated produced gas. Additional makeup water for steam production will be supplied from on-site water wells. At full production, the produced water and steam generation water requirements will be almost balanced.

Truck Loading and Unloading

Light crude oil will be brought to the Project site by truck to facilitate production oil dehydration and treatment, and meet transportation requirements for oil export. Light crude will be unloaded at four unloading racks, and stored in two 6,500 barrel tanks prior to use.

Blended produced oil will be loaded from storage at eight loading racks.

The following average daily truck traffic is projected when production is at full capacity:

- 94 trucks per day at 140 barrels per truck export of blended produced crude.
- 24 trucks per day at 140 barrels per truck import of light crude.

2.2 On-Site and Off-Site Populations

On-Site Personnel

After the construction phase, it is projected that there will be up to 50 Aera personnel working on-site during regular business hours, and 2 during off-hours (nights and week-ends). In addition, there will be contractors performing well maintenance activities, and truck drivers loading and unloading. Aera personnel and directly hired contractors are not included in the assessment of risks to the public, although they are considered for purposes of identifying potential vehicle ignition sources.

On-Site Public Population

Inside the Project boundary, there are wells operated by another production company, ERG Resources, LLC (ERG). There are also some areas included in the project scope, that are not owned by Aera. These include the road on the Fleisher lease, the wells and roads on the Bonetti lease, the proposed entrance to the site on ERG property, and the proposed electric power line location, owned by ERG.

Personnel associated with production from the ERG wells are considered “public” personnel, as they are not hired or contracted by Aera. There are currently 5 wells in the Bonetti, Fleisher and West lease areas in operation. It is anticipated that the number of non-Aera operated wells will increase during the duration of the Project, and have therefore assumed that a total of 10 non-Aera wells will be in operation. The locations of non-Aera operated wells are shown on Figure 2.1, and the number of associated personnel working regularly at these operating wells have been estimated as:

- 2 ERG personnel within the Project site, 50% of the time during normal work hours.

Off-Site Public Population

The off-site area was reviewed to identify populations that may be impacted by a hazardous release. The locations of off-site residences are shown on Figure 2.1. There are also several residential 10-acre plots to the north and east where dwellings may be located in the future. Several of these plots are currently up for sale.

The nearest residence to the CPF is located 2,600 feet to the south-south east of the proposed vapor recovery transfer line. This is outside the potential area for serious injury or fatality, and impacts would be less than significant. Other residences are located to the north and south-east. Distances to the nearest dwellings and residential plots are shown in Table 2.1

To the west and south of the Aera site are oil production facilities, some of which currently have idle wells. We have assumed that these wells will be redeveloped, increasing the off-site activity and numbers of workers associated with production at these sites. The currently active and idle wells adjacent to the Aera site are shown on Figure 2.1.

The offsite populations have been estimated as follows:

- Oil production area immediately west = average of 2 personnel during the day
- Oil production area immediately south = average of 2 personnel during the day
- Each dwelling = 2 persons, outside 10% of the time
- Cat Canyon Road = 2 vehicles per mile, 1 person per vehicle

2.3 Weather Data

The nearest weather station to the Project Site is at the Santa Maria airport. Meteorological data from the California Air Resources Board (CARB) internet site was utilized to characterize the wind speed and direction. The data is plotted as a wind rose in Figure 2.2, to illustrate the wind direction and speeds. The predominant wind blows from directions to the west and north-west 62 percent of the time. The average wind speed is approximately 4 meters per second.

Wind Direction	Percent Occurrence
N	5.7
NE	5.6
E	8.5
SE	7.2
S	3.7
SW	7.1
W	34.0
NW	28.2

Two meteorological conditions have been selected to represent worst case and more typical conditions. A worst case of “F” stability and 1.5 meters per second wind speed, represents low wind speed during the night when flammable vapors may accumulate. A more typical case of “D” stability and 4 meters per second wind speed, represents average weather conditions during the day and part of the night hours.

Stability Class	Wind Speed	Percent Occurrence
F	1.5 m/s (3.5 mph)	35 %
D	4 m/s (9 mph)	65 %

Figure 2.1 Map of Aera East Cat Canyon Oil Field

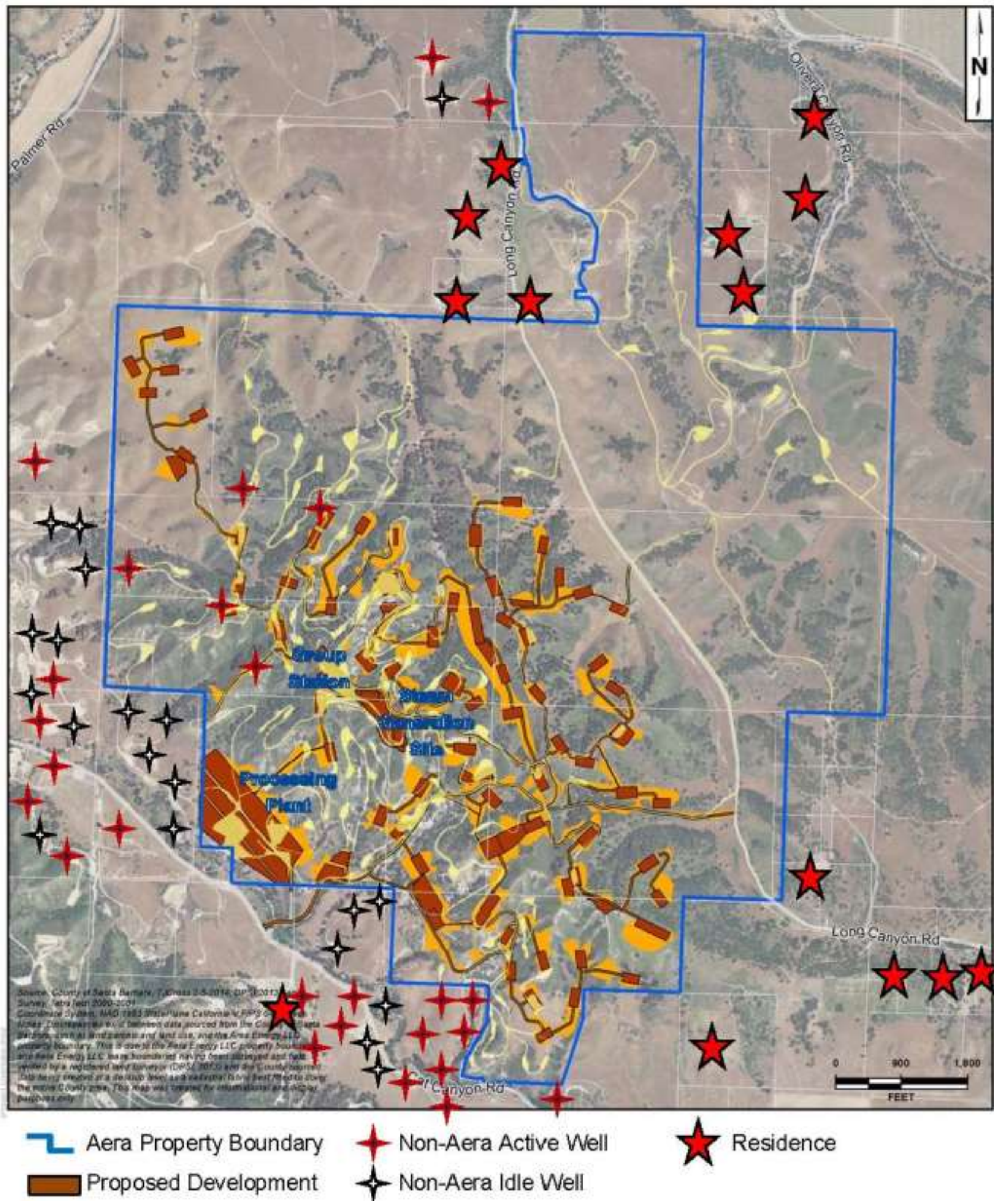
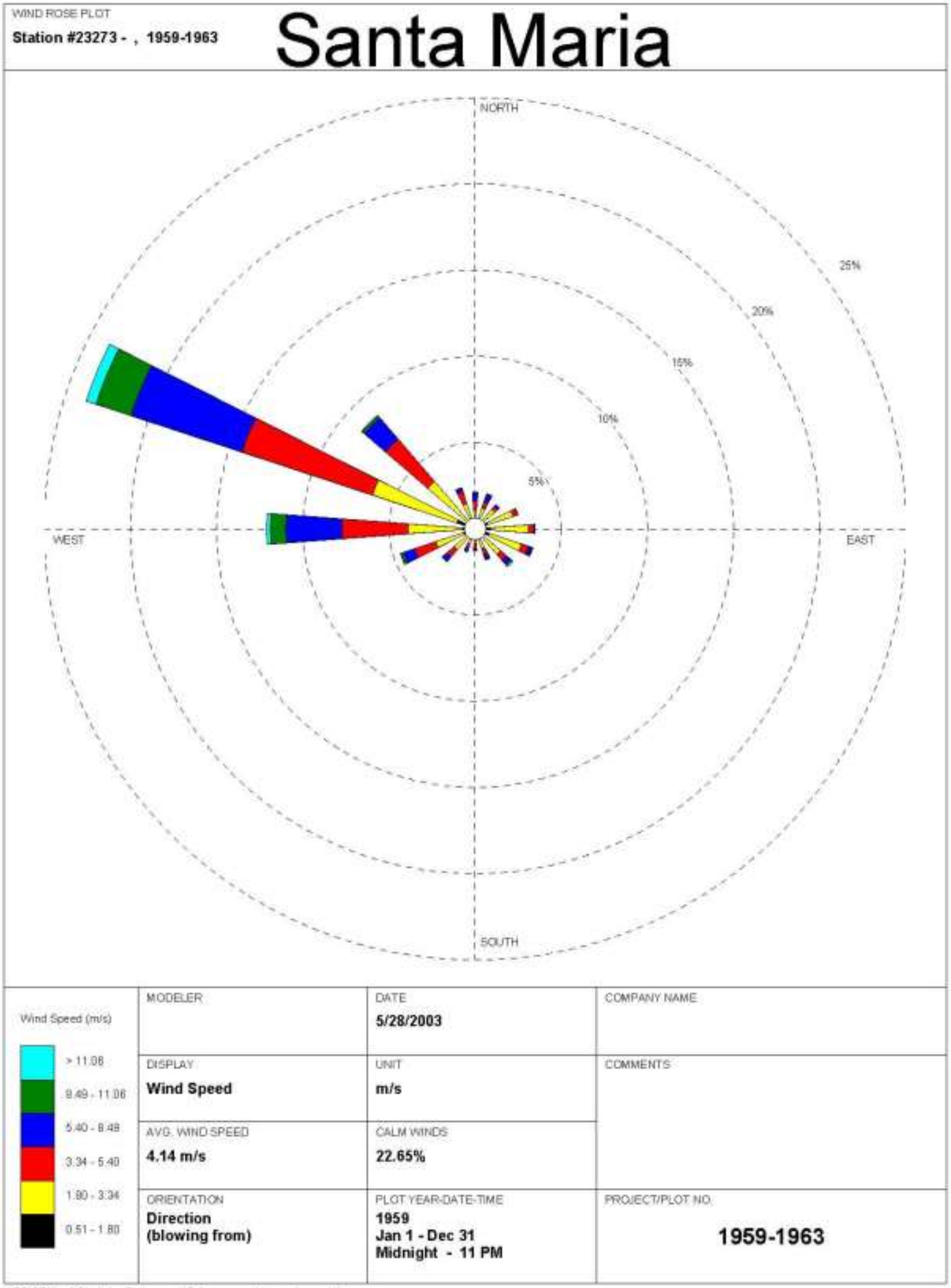


Table 2.1 Distances to Public Populations

Potential Release Source	Public Receptor	Direction	Minimum Distance (ft)
Production Well	Nearest Residence Off-Site Oil Production Area Nearest Non-Aera Well Site	SE S, W all	1,300 500 100
Gathering Lines, 3-inch	Nearest Residence Off-Site Oil Production Area Nearest Non-Aera Well Site	SE S, W all	1,300 500 100
Gathering Lines, 6-inch	Nearest Residence Off-Site Oil Production Area Nearest Non-Aera Well Site	SE S all	3,000 1,200 100
Gathering Lines, 8-inch	Nearest Residence Off-Site Oil Production Area Nearest Non-Aera Well Site	SW SW W	3,800 1,700 100
Group Station	Nearest Residence Nearest Non-Aera Well Site On-Site Access Road	S WWN NE	4,600 620 100
Produced Gas Treatment Plant	Nearest Residence Nearest Non-Aera Well Site On-Site Access Road	SSW WWN NE	4,400 940 200
Emergency Flare	Nearest Residence Nearest Non-Aera Well Site On-Site Access Road	SSW WWN NE	4,600 620 120
TVR Gas Transfer Line	Nearest Residence Off-Site Oil Production Area	SSE W	2,600 540
Fuel Gas Line – Inlet to Property	Nearest Residence Off-site Oil Production Area	SSE W	2,400 740
Fuel Gas Line – Inlet to Steam Generator Site	Nearest Residence Off-Site Oil Production Area Nearest Non-Aera Well Site	SSW W WNW	4,300 2,300 1,200
Crude Oil Storage	Nearest Residence Public Road	S SW	2,000 500
Crude Oil Loading/Unloading Area	Public Road	SW	650

Figure 2.2 Wind Rose Plot - Santa Maria Meteorological Station



3. HAZARD IDENTIFICATION

A review of the proposed Project operations has been made to identify potential hazards to the public of flammable and/or toxic releases. For each identified hazard scenario, an assessment was made of the maximum potential release and distance to off-site and on-site public populations. All other scenarios, even though they could produce on-site impacts in the immediate vicinity such as fires, steam or toxic hazards, are considered to be outside the scope of this study.

The following hazard identification methods were used:

- Identification of the material properties and process conditions.
- The potential consequences of a loss of containment for each system.
- Review of historical incident records.

A list of selected worst-case release scenarios are shown in Table 3.1 and discussed below.

3.1 Loss of Well Control

A well failure may occur during the development, production, maintenance, idle or abandonment phases, resulting in a potential hazard. This may involve a well blow-out or oil spill at the well site.

A blowout is an uncontrolled release of crude oil and/or natural gas and steam from an oil well when pressure control systems have failed. During drilling, a blowout could occur when the drill meets an area of high pressure, and the weight of the drilling fluid (mud) is insufficient to contain the reservoir fluids. Blowout preventers (BOPs) are installed at the top of the well during drilling and well maintenance, which can be closed in the event of loss of well control.

Hazards associated with loss of well control include high temperature oil and steam burns, toxic H_2S and flammable vapors. The maximum H_2S concentration in the produced gas is estimated to be between 5 and 10%. A maximum concentration of 10% has been assumed for this analysis. After the initial development phase, a release from the well will include large quantities of steam, making it unlikely that a flammable atmosphere could occur.

Development

During drilling operations in the development phase, the reservoir will be at low temperature and pressure. The crude oil is highly viscous and the reservoir is not anticipated to have sufficient pressure to free-flow to the surface and produce a blowout type of scenario; therefore the loss of well control during the development phase is considered an insignificant hazard.

Production
A production failure may occur due to failure of wellhead equipment, operator error, steam breakthrough or vehicle impact. As the reservoir temperature and pressure increases during operation, there will be a greater likelihood of an uncontrolled well release.

Well-Maintenance
Well servicing releases may occur during maintenance or well-kill. A blowout preventer failure or well failure when the BOP is being installed or removed can result in an uncontrolled release. It has been assumed that one-well servicing operation will be needed on each well per year.

3.2 Gathering Lines

Gathering lines will transfer the combined production fluids to a central Group Station. The lines are estimated to be sized from 2 to 8-inch in diameter. The pipe thickness will have an allowance for erosion (due to sand in the oil) and the presence of H_2S.

A gathering line failure may cause a hazardous release of produced gas, oil, water and steam. Due to the high temperature, a release will cause some of the water to flash to steam, diluting the produced gas and H_2S.

The Group Station is to be located in the central area of the site. A gathering line failure closest to off-site public will be on smaller lines with lower flow rates. The larger main gathering lines will be located closer to the central area of the site.

The total length of gathering lines at full production is projected to be about 70,000 feet. The gathering system will operate at approximately 250 psig and 400°F. The well and gathering system pressure will be maintained by pressure control at the production group separator to reduce flashing of the produced water in the well tubing and surface piping.

Gathering line lengths, sizes and flow rates have been estimated as follows:

Gathering Line Diameter	Line Lengths		Gas Flow Rates		Liquid Flow Rates	
	ft	miles	MCFD	lb/min	MBPD	lb/min
2 to 3 inches	21,000	4.0	60	3.3	2.8	675
4 to 6 inches	35,000	6.6	250	14	12	2800
8 inches	14,000	2.7	500	28	23	5,600

3.3 Group Station

The combined production of oil, water and gas will be separated at the Group Station, located near the central steam generators. The pressure will be reduced to 25 psig immediately upstream of the group separators. Two parallel trains will be installed, the second one being added for phase 2 production.

At the group separators, produced gas and vapor will be separated from the liquids at approximately 25 psig and 260ºF. The horizontal pressure vessels will have about 5 minutes liquid retention time and provide surge capacity.

The worst case hazard will be a line or vessel failure that results in the release of the production gas flow from one of the separation trains. A worst case release of 500 MCFD production gas at 10% H_2S has been assumed. Failures could also occur due to operational or equipment errors leading to a release of production gas through the relief system to the 20-feet vent stack. Either scenario is unlikely to impact offsite due to the central location of the Group Station.

3.4 Produced Gas Treatment Plant and Emergency Flare

Produced gas from the Group Separators will be cooled to remove water, then compressed. The produced gas will combined with Tank Vapor Recovery (TVR) gas transferred from the CPF. The combined sour gas will be treated in sulferox and sulfurtreat units to remove H_2S. The treated gas will then be used as fuel in the produced gas steam generator located at the Steam Generator Site. A line or vessel failure at the Produced Gas Treatment Plant (PGTP) may result in a worst case release of 2,000 MCFD produced gas at 10% H_2S.

An emergency flare, with a continuous pilot flame, will be used to dispose of gas from process safety valves or a failure at the Produced Gas Treatment Plant. The elevated flare will be 35 feet high, 6-inch diameter, and located at the Group Station. A worst case release would occur if the flare release was unignited.

A second flare will also be provided for stand-by purposes. The stand-by flare will be in operation during planned outages of the produced gas steam generator, and will burn sweetened produced gas.

3.5 Oil and Gas Transfer Lines

Production liquids from each Group Separator will flow through separate transfer lines to parallel oil treating trains in the Central Processing Facility. Production gas from both separation trains will be treated in the Produced Gas Treatment Plant.

A release of oil from one of the two produced oil and water transfer lines would not result in an offsite toxic or flammable hazard. There will be dissolved H_2S in the produced water, although not in sufficient quantities to result in a significant hazard except in the immediate vicinity. The flashing of steam on release will disperse and dilute any H_2S and flammable vapors released. The hazards to personnel will include hot oil, steam and H_2S exposure.

Compressed sour vapors from the Tank Vapor Recovery Units at the CPF will flow to the PGTP for treatment. A line failure or large hole in the TVR transfer line could produce a flammable and toxic vapor cloud. Ignition of the flammable vapor could result in a jet flame and local thermal radiation hazard.

The following line conditions have been assumed:

Transfer Line Diameter	Line Conditions		Line Length		Flow Rate	
	Pressure	Temp	ft	miles		lb/min
TVR Gas 4 inch	30 psig	120ºF	2,800	0.5	1000 MCFD	34
Production Liquid 2 x 8 inch	150 psig	260ºF	2,800	2 x 0.5	23 MBPD	5,600

3.6 Oil Cleaning Plant

Produced oil and water will be treated in two parallel cleaning plants. The heavy bituminous oil will be about 9.0 API during the early years of production, and the gravity increase to about 7.6 API during peak production in later years. To treat the heavy oil, imported light crude oil will be blended into the cleaning plant feed. The oil will pass through a series of vessels to remove sand, gas and free water. Gas from oil cleaning will be combined with the TVR gas, compressed, and transferred to the Produced Gas Treatment Plant.

A line or vessel failure at the oil cleaning plant may result in the release of sour gas. Most production gas will be removed at the Group Separator, although some H_2S and gas will remain dissolved in the liquids. However, the quantities of gas would be small and unlikely to result in a significant hazard to the public.

3.7 Fuel Gas Lines

Natural gas will be obtained via a new pipeline connection to a Southern California Gas Company pipeline. The natural gas will be used as fuel in the steam generators, and makeup gas for storage tanks. A failure of a natural gas line could create a potential fire and/or explosion hazard. The line lengths and sizes assumed are listed below. The fuel gas composition is shown in Table 5.1.

Fuel Gas Line Diameter	Line Conditions		On-Site Line Length		Gas Flow Rate	
	Pressure	Temp	ft	miles	MCFD	lb/min
6 inches to main steam generators	250 psig	60ºF	2,800	0.5	12,000	400
3 inch lengths to each generator	250 psig	60ºF	200	0.04	2,000	66
3 inch length to produced gas steam generator	250 psig	60ºF	50	0.01	1,500	50

3.8 Steam Generation, Distribution and Injection

A total of seven (7) steam generators will be built with a nominal steam rate of 33,000 BSPD. Saturated steam will be produced at approximately 2,400 psig, 662ºF and 70% quality, with steam injection into the well at 1,900 psig. The following steam generators will be installed:

6 x 85 MMBtu/hr units, (5,000 BSPD) located in a central area of the site.
1 x 62.5 MMBtu/hr unit, (3,000 BSPD) to utilize sweetened produced gas and SoCal Gas fuel supply.

The following potential hazards are associated with steam generator operation:

- Vapor cloud hazard due to the release of fuel gas
- Steam generator boiler explosion
- Release of high temperature steam

Steam generation and distribution creates a high temperature hazard in the immediate vicinity of the release, but does not pose a significant risk to public populations. A release of fuel gas due to a line failure is discussed above in Section 3.7.

3.9 Crude Oil Storage

Produced heavy crude oil mixed with imported light crude oil will be stored in two 10,000 barrel tanks prior to transportation by truck. Light crude oil (approximately 29 API) will be imported via truck and stored in two 6,500 barrel tanks for mixing with the heavy crude prior to treatment. The lighter crude oil is needed to decrease the produced crude oil API density to a minimum of 12 API for separation and transportation. A list of the crude oil storage tanks, containment basin, and sizes is shown below. A separate lined basin will provide additional containment in the event of a large tank release.

The tank vapor recovery system is assumed to maintain a vapor pressure of 0.06 psig. Make-up gas will be added to the vapor space to maintain a slight pressure, and any produced vapors will be recovered, compressed, and treated in the PGTP.

A major storage tank failure may occur due to catastrophic tank failure, connection failure, tank overfill, earthquake or boil-over after a prolonged tank fire. A release of crude oil into the dike area will cause a flammable vapor cloud. If a release is ignited, a dike fire may escalate to involve the storage tank. An uncontrolled crude oil tank fire may result in a boil-over if sufficient water is present, and eject boiling oil up to 1,300 feet.

Tank Number	Tank Description	Capacity (bbls)	Temp (ºF)	Diameter (ft)	Height (ft)	Approx Dike Dimensions (ft)
T-2170	Produced Oil	10,000	190	55	24	158 x 95
T-2180	Produced Oil	10,000	190	55	24	158 x 95
T-2040	Light Crude Oil	6,500	80	44	24	158 x 95
T-2050	Light Crude Oil	6,500	80	44	24	158 x 95
Basin	Lined Containment	15,300				8,600 ft^2

3.10 Crude Oil Loading/Unloading

Crude oil production and light crude for mixing will be transported via truck. When the field is at full capacity, it is estimated that 3,300 BOPD of light crude oil will be needed to blend with the heavy production crude. The light crude oil will be imported by MC 306 or MC 307 cargo trucks in 140 barrel loads. This will require an average of 24 truck loads per day.

A total of 13,300 BOPD of blended production crude oil will be exported by trucks in 140 barrel loads. An average of 94 trucks per day will be utilized.

A potential hazard may occur due to a loading/unloading error, or a truck vehicle collision that causes a rupture or leak of the tanker on site. A maximum spill size of 140 barrels has been assumed.

3.11 Earthquake Hazards

The risk of an earthquake causing a hazardous release has been examined and included in the overall likelihood of release. An earthquake could result in the failure of a gathering line, gas transfer line, processing equipment or storage tank.

Above ground pipelines and tanks have more flexibility and are less at risk of seismic failure. Pipelines and equipment will be designed to seismic safety standards, which allow some flexibility and movement, although a large earthquake has the potential to exceed the design limits.

A review was made of earthquake reports to assess the likelihood of earthquake damage to process equipment. An assessment was then made of the probability of an earthquake occurring that could cause this damage. The potential for equipment damage is reported as peak ground acceleration (PGA). This provides a measure of the strength of ground shaking, and is used in literature studies to predict damage and analyze historical incidents.

Table 3.1 Summary of Worst-Case Release Scenarios

Release Source	Scenario
1. Loss of Well Control Development Phase Production Phase Well-Maintenance	Well blow-out or oil spill. Release of hot oil, steam and production gas at maximum conditions. Loss of well control unlikely during development phase due to low reservoir pressure and temperature.
2. Gathering Lines	Gathering line failure and release of hot oil, water, H_2S and produced gas. Line sizes estimated from 2 to 8-inch in diameter. Worst case conditions 500 MCFD gas, 10% H_2S, 250 psig and 400ºF.
3. Group Station	Line or vessel failure that results in the release of the production gas flow from one of the group separation trains. Potential relief gas release to atmosphere.
4. Sour Gas Treatment Plant and Emergency Flare	Worst case release of 2,000 MCFD produced gas at 10% mol H_2S. Unignited release of H_2S from 35 feet, 6-inch diameter emergency flare.
5. TVR Gas Transfer Line	Gas transfer line failure at 30 psig and 120ºF, 4 inch line at 34 lb/min flow rate.
6. Oil Cleaning Plant	Line or vessel failure resulting in the release of gas with high H_2S content. Entrained gas quantities will be low and may result in an on-site hazard in the immediate vicinity.
7. Fuel Gas Lines	Failure of a 3 or 6-inch natural gas line. Potential fire and/or explosion hazard.
8. Steam Generation	No significant risk to offsite populations. Fuel gas line failure addressed above.
9. Crude Oil Storage	Major storage tank failure resulting in pool evaporation, vapor cloud fire, tank fire and possible boil-over.
10. Crude Oil Loading/Unloading	Release due to truck loading/unloading incident. Potential vehicle collision on site and spill of crude oil resulting in flammable vapor and /or fire hazard.

4. RELEASE FREQUENCY ASSESSMENT

The likelihood that a hazardous release will occur, and the potential size of the release has been estimated using published generic failure rate data. The data has been generated from incident records gathered over a variety of installations and therefore represents an industry average.

The failure rate of a piece of equipment is influenced by a large number of factors, including: design specification, manufacture, application, operating conditions and maintenance. The same piece of equipment may be used in a wide variety of operating conditions and environments, and some attempts have been made to allow for these factors as described in the derivation of equipment failure rates.

The likelihood of failure for each potential release source is described below, and summarized in Table 4.1.

4.1 Well Failure Rates

A blowout is defined as an uncontrolled release from a well. Most well control problems are either quickly controlled by the normal safety equipment, or result in a minor release and are not included in the category of "blowout" in published incident data.

Statistics on the number of uncontrolled well releases for onshore production wells are not widely available. There are news releases on major incidents and some limited reporting on incidents in California[5] and Texas. Data on well blowouts is readily available for offshore incidents in the Gulf of Mexico and the North Sea. The US Bureau of Safety and Environmental Enforcement (BSEE, formerly BOEMRE and MMS) publish data on offshore incidents in the Gulf of Mexico, and the international E&P Forum[13] publish data on the frequency of international blowouts.

The likelihood of a well failure resulting in an oil spill at Cat Canyon Oil Field is expected to be lower than industry average due to the following: the oil is highly viscous, reservoir pressure is low, and the liquid does not flow to the surface without lift assistance (e.g. a pump).

Failure rates are reported by BSEE and the E&P Forum for oil wells as follows:

Drilling and completion	8.2×10^{-4} per well (one every 1200 wells drilled)
Well Servicing	4×10^{-4} per well servicing
Production	4.6×10^{-5} per well-year

The likelihood of a loss of well control during the drilling and completion phase is highly unlikely. The reservoir is at low pressure and the viscous oil does not flow without lift assistance. Only failure rates for well servicing and production have been considered.

Failure rates for oil and gas wells in California have been analyzed from a report on the History of Oil and Gas Well Blowouts in California, 1950 to 1990, published by the California Division of

Oil, Gas and Geothermal Resources, 1993[5]. The data is based on a smaller population of wells than the BSEE and E&P Forum data, and the incident reporting for earlier years may not be as complete as the offshore data. The following failure rates have been calculated from this data:

Well Servicing and Production	3.1×10^{-4} per well-year
Well Idle	1.4×10^{-4} per well-year

The failure rates reported in California are very consistent with those published by the BSEE and E&P Forum. We have selected the failure rate for California onshore production to represent the likelihood of well failure. The overall failure rates for loss off well control are:

Operational Phase	Well Failure Rate	Count	Release Frequency
Production	3.2×10^{-5} /well	141operational wells/year	4.5×10^{-3} /yr
Well Servicing	2.8×10^{-4} /servicing	141services/year	3.9×10^{-2} /yr
Well Idle	1.4×10^{-4} /well-year	10% of wells idle/year	2.0×10^{-3} /yr
Total Well Failure Rate			**4.6×10^{-2} /yr (1 in 22 yrs)**

4.2 Gathering Line Failure Rates

The likelihood of a release from a gathering or production line or has been developed by analyzing published failure rate data for pipelines, gathering lines and process stream lines. Pipeline failures resulting in oil spills or gas release have been reported in both the US and Europe for many years, providing an excellent source of detailed information on failure rates. Reports from the California State Fire Marshal[6, 7], Alberta Energy and Utilities Board[1], American Gas Association[18, 19], European Gas Data[14], the API[2] and CONCAWE[12] have been used to develop failure rates and scenarios for gathering line releases at the Project site.

Each of the reports on pipeline failures provides data on “reportable incidents”. The reporting criteria for each of the studies vary, making direct comparisons difficult. The line size, service, corrosion protection and operation of the pipelines in each of the studies also vary. However, many of the sources provide details that allow some “normalization” of data for comparison. The release sizes and causes of release have been assessed to select appropriate incident rates for oil gathering lines.

4.2.1 Reported Line Failure Rates

The following incident rates have been reported in literature:

Source	Incident rate per 1,000 mile-years	Damage Criteria	Average Diameter (in)
California State Fire Marshal (CSFM) Hazardous Liquid Pipelines[7] Crude Oil Lines Only	5.3 4.4 9.9	>$5,000 >$50,000 All Leaks	12 12 15
California State Fire Marshal (CSFM) Low Pressure Crude Oil and Gathering Lines[6]	6.7 1.3	>$1,000 >$10,000	7.5
Alberta EUB[1] Multiphase Gathering Lines	13.0	All leaks	5.5
American Gas Association AGA US Gas Transmission and Gathering Lines 1970-1984[18]	1.3	> $5,000	17
CONCAWE 42 year Performance Statistics – 2012[12]	0.85	>6 bbls	15
US DOT Pipeline and Hazardous Materials Safety Administration 1986-1992	1.3	> $5,000 or > 50 bbls	

The study published by the CSFM on Low Pressure Crude Oil and Gathering Lines in 1997 provides a comparable set of data to the lines at the Aera Cat Canyon project, but is based on a small population of pipelines, only 1,486 mile-years. The average pipe diameter was 7.5-inches, and the lines included in the study were primarily rural crude oil gathering lines at ambient temperature.

Oil and gas pipeline operators in Alberta, Canada are required to report all leaks to the Energy Resources Board (EUB). This data provides information on failure rates by type of pipeline, including multi-phase lines. The gathering lines are typically underground small diameter pipelines located in rural areas. The overall failure rate for EUB gathering lines appears higher than that reported in the CSFM reports, but the average pipeline diameter is smaller.

4.2.2 Release Cause

From reported data, small releases were predominantly caused by corrosion leaks, with a median spill quantity of 3 barrels. Larger releases were more often caused by third party impact or interference and construction or material defect.

In the QRA study, only larger releases that may result in risks to the public have been considered. Therefore, small releases from the CSFM and EUB data have been excluded which then provides the following release cause distribution:

40%	Third Party
20%	Corrosion
20%	Construction / Material Defect
20%	Operator Error, Natural Hazards and Miscellaneous

Internal corrosion rates for gathering lines are reported to be higher than product lines due to the higher percentage of water and other impurities. External corrosion rates are reported to be higher on lines operating at higher product temperatures.

4.2.3 Pipeline Diameter

Pipeline incident rates are reported to be highly dependent on the diameter of the line. The incident rate may vary by nearly an order of magnitude between 4-inch and 28-inch pipelines[7, 14, 18]. This has been largely attributed to the increase in pipe wall thickness with larger diameter lines. From literature reports, a pipeline diameter factor has been developed as follows:

Pipeline Diameter	Diameter Factor
2 to 3 inches	3
4 to 6 inches	1.6
8 to 10 inches	1.2
12 to 16 inches	1

4.2.4 Distribution of Release Sizes

The distribution of release sizes has been estimated from the reported frequencies of hole size and resulting release quantity[1, 12, 14]:

Large / Rupture	15%
Medium Hole (1-inch)	30%
Small Hole (<1/2-inch)	55%

4.2.5 Operating Temperature

The CSFM Liquid Pipeline study indicates that operating temperature has an effect on leak incident rates. It was reported that the higher the operating temperature, the higher the incident rate. An increase in average temperature from 75ºF to 178ºF was found to increase the incident rate by a multiple of 3.6, primarily due to an increase in external corrosion rate. A similar temperature effect was found by CONCAWE, where heated fuel oil lines had a reported incident rate of approximately 4 times higher than pipelines at ambient temperature. The higher incident rate for hot pipelines has been attributed to external corrosion issues when metal pipes are in contact with soil moisture.

The maximum operating temperature on the oil gathering lines at the Cat Canyon Project is projected to be about 400ºF. This is significantly higher than any of the pipelines in published data. Gathering lines at the Cat Canyon Project will be above ground, and may not be exposed to the same external corrosion issues as buried lines in published data. At road crossings, the gathering lines will be protected within a concrete vault.

Due to the uncertainties in predicting the influence of temperature and increased pipe rating on above ground gathering lines, no adjustment has been made on the predicted incident frequencies.

4.2.6 Gathering Line Release Frequencies

The failure rates presented in the reports on California Low Pressure Crude Oil and Gathering Lines, and Hazardous Liquid Pipelines[5, 6] and Alberta EUB gathering lines[1] have been selected as the basis for developing gathering line release rates. These failure rates are higher than reported for interstate liquid and gas pipelines, but are more appropriate for the design and operating conditions of infield lines. The published data has been adjusted to take account of the average pipe diameter, and exclude small releases. The release rates applied for above ground lines are as follows:

Gathering Line Diameter	**Line Lengths** (miles)	**Failure Rate** (per mile-yr)		**Release Frequency** (per year)	
		Medium Hole (1-inch)	**Large / Rupture**	**Medium Hole (1-inch)**	**Large / Rupture**
2 to 3 inches	4.0	8.9×10^{-3}	4.5×10^{-3}	3.6×10^{-2}	1.8×10^{-2}
4 to 6 inches	6.6	4.8×10^{-3}	2.4×10^{-3}	3.2×10^{-2}	1.6×10^{-2}
8 inches	2.7	3.6×10^{-3}	1.8×10^{-3}	9.7×10^{-3}	4.9×10^{-3}
Total	13.3			7.8×10^{-2} (1 in 13 yrs)	3.9×10^{-2} (1 in 26 yrs)

4.3 Group Station Failure Rates

The worst case hazard will be a line or vessel failure that results in the release of the production gas flow from one of the separation trains. A vessel or piping rupture is considered to be a complete failure or large hole that results in the rapid release of the contents.

Catastrophic failure of properly designed, constructed and operated pressure vessels is comparatively rare. Most pressure vessel failures occur due to a failure in operating or maintenance procedures. There are several data sources that report on historical failure rates process pressure vessels. These included Center for Chemical Process Safety (CCPS) of the AIChE, Smith and Warwick, and Lees[9, 23, 20]. CCPS quote an average failure rate for "significant" failures as 1×10^{-4} per year. From data reported by Smith and Warwick, and Lees, a large release or rupture occurs at about 1×10^{-5} per year.

The failure of piping associated with a separator vessel may also result in the rapid release of the contents. A study performed by the US Atomic Energy Authority[26] (WASH-1400) has the largest population of piping failure rate data. These represent base failure rates for process piping in an environment where there is minimal vibration, corrosion and erosion. A correction factor of 5 has been applied due to the potential for corrosion and erosion. The failure rates reported in WASH-1400 are comparable with other data sources reviewed.

The total line length associated with the 2 separators is estimated to be 100 feet. The overall failure rates have been estimated as follows:

Equipment	**Hole Size**	**Failure Rate**	**Count**	**Release Frequency** (per year)
Pressure vessel	1-inch hole	1×10^{-4} /yr	2 Separators	2×10^{-4} /yr
	Large / Rupture	1×10^{-5} /yr		2×10^{-5} /yr
Linework (8-inch or greater)	1-inch hole	2×10^{-7} /ft-yr	100 feet	2×10^{-5} /yr
	Large / Rupture	1×10^{-7} /ft-yr		1×10^{-5} /yr
Total	1-inch hole			2.1×10^{-4} /yr
	Large / Rupture			3×10^{-5} /yr

Failures could also occur due to operational or equipment errors leading to a release of production gas through the relief system to the 20-feet vent stack. The group separators will be provided with high pressure trip systems to shut-in the production wells, and are specified with a design pressure of 425 psig MAWP. An estimate has been made of the likelihood of a release to flare as:

- Automatic shutoff fails to close, 1 in 100 per demand[20, 24],
- 2 demands per year,
- Frequency of release to vent = 2×10^{-2} (1 in 50 yrs)

4.4 Produced Gas Treatment Plant and Emergency Flare

A line of vessel failure at the Produced Gas Treatment Plant may result in a release of produced gas at ground level. A release of gas prior to H_2S removal will contain up to 10% H_2S. The likelihood of release has been estimated from the failure rate of 3 vessels and associated piping as follows:

Equipment	Hole Size	Failure Rate	Count	**Release Frequency** (per year)
Pressure vessel	1-inch hole	1×10^{-4} /yr	3 Vessels	3×10^{-4} /yr
	Large / Rupture	1×10^{-5} /yr		3×10^{-5} /yr
Linework (8-inch or greater)	1-inch hole	2×10^{-7} /ft-yr	150 feet	3×10^{-5} /yr
	Large / Rupture	1×10^{-7} /ft-yr		1.5×10^{-5} /yr
Total	1-inch hole			3.3×10^{-4} /yr
	Large / Rupture			4.5×10^{-5} /yr

A worst case release of sour gas to the emergency flare may occur due to an operational or equipment failure at the plant. This may occur on average once a year. The likelihood of ignition failure has been assumed to be in the same order of magnitude as the failure of an automatic shutoff valve, 1 in 100 demands. The likelihood of an unignited worst case H_2S release from the flare is estimated as 1 in 100 years.

4.5 Oil and Gas Transfer Line Failure Rates

It has been assumed that the oil and gas transfer lines will have the same likelihood of failure as the gathering lines described above in Section 4.2. The overall failure rates have been calculated as follows:

Transfer Line Diameter	**Line Lengths** (miles)	**Failure Rate** (per mile-yr)		**Release Frequency** (per year)	
		Medium Hole (1-inch)	Large / Rupture	Medium Hole (1-inch)	Large / Rupture
TVR Gas 4 inches	0.5	4.8×10^{-3}	2.4×10^{-3}	2.4×10^{-3}	1.2×10^{-3}
Production Liquid 2 x 8 inches	1	3.6×10^{-3}	1.8×10^{-3}	3.6×10^{-3}	1.8×10^{-3}
Total	1.5			6.0×10^{-3} (1 in 170 yrs)	3.0×10^{-3} (1 in 330 yrs)

4.6 Oil Cleaning Plant

A line or vessel failure at the oil cleaning plant may result in the release of sour gas. The quantities of gas would be small and unlikely to result in a significant hazard except to employees in the immediate vicinity. Therefore, no frequencies of failure have been developed for this area of the facility.

4.7 Fuel Gas Lines

Failure rates reported by the American Gas Association[18] (AGA) for gas transmission and gathering lines has been selected to represent the likelihood of failure of the fuel gas lines. A line diameter correction factor was applied to the base failure rate, which represents an average pipeline size of 17-inches. The minimum reporting damage criteria for the AGA lines was $5,000. We have assumed these represent the medium and large release sizes. The overall failure rates have been calculated as follows:

Fuel Gas Line Diameter	**Line Lengths** (miles)	**Failure Rate** (per mile-yr)		**Release Frequency** (per year)	
		Medium Hole (1-inch)	**Large / Rupture**	**Medium Hole (1-inch)**	**Large / Rupture**
3 inches	0.05	2.6×10^{-3}	1.3×10^{-3}	1.3×10^{-4}	6.5×10^{-5}
6 inches	0.5	1.4×10^{-3}	6.9×10^{-4}	7.0×10^{-4}	3.5×10^{-4}
Total	0.64			8.3×10^{-4} (1 in 1200 yrs)	4.2×10^{-4} (1 in 2400 yrs)

4.8 Steam Generation, Distribution and Injection

Steam generation and distribution creates a high temperature hazard in the immediate vicinity of the release, but does not result in a significant public hazard. Therefore, no frequencies of failure have been developed for steam generation and distribution.

4.9 Crude Oil Storage Tank Failure Rates

A major tank failure may be due to the failure of a pipe connection, failure of the tank shell, overfill, ignition of vapor within a tank, or earthquake.

Storage Tank Failures:
A number of data sources were reviewed for generic failure rates of storage tanks, including the CCPS [9], the TNO Purple Book[10], Lees[20] and FEMA[15]. CCPS and FEMA quote an average failure rate for "significant" failures as 1×10^{-4} per tank-year. These include larger hole sizes and catastrophic failures. The likelihood of a catastrophic rupture of a storage tank is reported as occurring 5×10^{-6} per tank-year.

Tank Overfill:
The likelihood of a tank overfill is dependent on the type of instrumentation provided for level control and the frequency of filling. Failure rates are reported in the order of 1×10^{-2} per tank-year to 1×10^{-4} per tank-year or less[20, 27] (one in 100 to 10,000 years per tank). It is estimated that the overfill rate will be approximately 1×10^{-3} per tank-year (one in 1,000 years).

Storage Tank Boil Over:
A boilover is a sudden and violent ejection of oil from the tank resulting from a reaction of the hot layer of burned oil and the accumulation of water at the bottom of the tank. When the two layers meet, the water is superheated and subsequently boils and expands explosively. In a study of storage tank fires(16), approximately 3% of the fires in crude oil tanks have resulted in boilovers, giving an incident rate of 4×10^{-5} per tank year. A boilover may occur in fully developed, uncontrolled crude oil or fuel oil tank fire. The entire contents of the tank may be ejected creating a fireball and a wave of burning oil. This is primarily a hazard to response personnel, as boilovers occur several hours after a full surface tank fire develops and all other on and off-populations will have been evacuated.

The overall storage tank failure rates have been calculated as follows

Equipment	**Release Size**	**Failure Rate** (per tank-yr)	**Count**	**Release Frequency** (per year)
Storage tank	Rupture	5×10^{-6}	4	2×10^{-5}
	2-inch hole	1×10^{-4}	4	4×10^{-4}
Tank Overfill	Production or Loading rate	1×10^{-3}	4	4×10^{-3}
Tank Boil Over	Boiling oil ejected from tank	4×10^{-5}	4	1.6×10^{-4}

4.10 Crude Oil Loading/Unloading

A potential hazard may occur due to a loading/unloading error, or an on-site truck vehicle collision that causes a rupture or leak of the tanker on site.

The failure rate for loading selected is that reported by the UKHSE(25) as 4 failures per million operations at a typical facility. This assumes that the trucks use wheel chocks and interlock bakes, and the facility has an effective hose inspection program.

Truck accident rates are reported in published data as vehicle miles traveled. These range from 0.5 to 13 accidents per million miles(17). The highest accident rate was at collectors, ramps and intersections on city streets. Traffic at the loading facility will be more comparable to conditions on city streets than on a highway. An accident rate of 13 accidents per million miles has been conservatively applied, and an equivalent distance of 0.5 miles per truck visit.

The release probability, given an accident, is reported by Harwood(17) to be between 5% and 9%. A review of transportation data by Arthur D. Little in 1990(4) reported a conditional probability of a large spill from a gasoline truck as 7%. A release probability of 7% has been selected, although at the truck loading facility lower speeds may reduce the potential for a severe collision and release.

Source	Release Size	Failure Rate	**Count** (per year)	**Release Frequency** (per year)
Loading / Unloading	Large / Rupture	4×10^{-6} per operation	46720 load / unload	1.9×10^{-1}
Truck collision	Major Tank Failure	13×10^{-6} accidents per mile 0.07 major releases per accident	46720 truck movements 0.5 miles per truck	2.1×10^{-2}

The light crude oil will be imported by MC306/MC307 cargo trucks in 140 barrel loads at an average of 24 truckloads per day at full production.

A total of 13,300 BOPD of blended production crude oil will be exported by MC306/MC307 cargo trucks in 140 barrel loads. An average of 94 trucks per day will be utilized.

A potential hazard may occur due to a loading/unloading error, or a truck vehicle collision that causes a rupture or leak of the tanker on site.

4.11 Earthquake Failure Rates

The Project site is located in California's seismically active central coast region where there are a number of active faults with the potential to produce strong ground motion. In the Project area, two inactive faults have been mapped, the Garey fault and the Fuglar fault. Neither fault is considered likely to pose a surface rupture hazard capable of causing extensive equipment damage. An inactive fault is a fault which has not moved in the last 500,000 years.

Strong ground shaking due to an earthquake in the region may cause damage to linework, piping connections or storage tanks, resulting in a release. The likelihood of ground shaking is reported as hazard maps by the US Geological Survey[32]. These hazards are expressed in terms of the probability of exceeding a calculated strength. For example, the map showing a 10% probability of exceedance in 50 years show an annual probability of 1 in 475 of the peak ground acceleration projected for the area being exceeded each year. The likelihood of peak ground acceleration (PGA) at the Project site is reported by the USGS as:

Probability of Exceedance	Frequency	PGA (g)
10% in 50 years	2×10^{-3} /year (1 in 475 years)	0.26 g
2% in 50 years	4×10^{-4} /year (1 in 2,475 years)	0.49 g

Where: PGA = Peak Ground Acceleration
g = acceleration due to gravity

An earthquake which produces a PGA of 0.6g or greater is estimated to occur at a frequency of less than 1 in 100,000 years (1×10^{-5} /year).

A report published by the California State Fire Marshal(7) examined the history of underground hazardous liquid pipeline failures due to earthquake damage, and provides a prediction of the number of incidents expected. Incident rates were reported as:

0.2 to 0.3g PGA	0.0039 incidents per mile of pipe	3.9×10^{-3} /mile-year
0.3 to 0.65g PGA	0.035 incidents per mile of pipe	3.5×10^{-2} /mile-year

Above ground linework such as at Project site will have significantly lower failure rates. The lines are not constrained by soil and are designed with some flexibility. The incident rate for above ground lines at the Project site has been estimated to be an order of magnitude lower than below ground line, and distributed as two-thirds medium sized failures and one-third large failures or ruptures:

Release Size	Failure rate
Medium	1.5×10^{-5} /mile-year
Large / Rupture	7×10^{-6} /mile-year

Historical damage reports from earthquakes have been reviewed to develop predictions of potential damage to storage tanks and connections. When oil tanks are shaken during an earthquake the tank mass vibrates, and the surface of the oil may swing back a forward, “sloshing”. This makes the failure rate of storage tanks higher than other process equipment. From a review of damage reports, a facility may experience minor damage to process equipment during an earthquake, but major damage and loss of 5 to 10 percent of the storage tanks.

Data on storage tank failure due to earthquakes has been compiled by Salzano et al (21) from observations of earthquakes from Long Beach 1933 to Northridge 1994. Damage reports from three subsequent earthquakes after the Salzano data was compiled have also been reviewed; Kobe, Japan (1995), Kocaeli, Turkey (1999), and Tokacki-oki, Japan (2003). The probability of significant tank or connection damage has been estimated as:

0.2 to 0.3g PGA	0.05 per tank
0.3 to 0.65g PGA	0.1 per tank

Release Size	Failure rate
Medium	1×10^{-3} /tank-year
Large / Rupture	5×10^{-4} /tank-year

The predicted earthquake failure rates for lines and storage tanks have been added to the generic failure rates shown in Table 4.1.

Table 4.1 Summary of Predicted Release Frequencies

Release Source	Release Size	Release Frequency (per year)	Likelihood
Loss of Well Control			
Production	Blowout	4.5×10^{-3}	1 in 222 years
Well Servicing	Blowout	3.9×10^{-2}	1 in 26 years
Well Idle	Blowout	2.0×10^{-3}	1 in 500 years
Gathering Lines	Medium	7.8×10^{-2}	1 in 13 years
	Large / Rupture	3.9×10^{-2}	1 in 26 years
Group Station			
Group Separator	Medium	2.1×10^{-4}	1 in 4,800 years
Group Separator	Large / Rupture	3×10^{-5}	1 in 33,000 years
Release to Vent	Production flow rate	2×10^{-2}	1 in 50 years
Produced Gas Treatment	Medium	3.3×10^{-4}	1 in 3,000 years
Plant	Large / Rupture	4.5×10^{-5}	1 in 22,000 years
Emergency Flare	Large Unignited	1×10^{-2}	1 in 100 years
Oil and Gas Transfer Lines			
TVR Gas	Medium	2.4×10^{-3}	1 in 420 years
TVR Gas	Large / Rupture	1.2×10^{-3}	1 in 830 years
Fuel Gas Lines	Medium	8.3×10^{-4}	1 in 1,200 years
	Large / Rupture	4.2×10^{-4}	1 in 2,400 years
Crude Oil Storage Tanks			
Storage tank	Medium	4.4×10^{-3}	1 in 227 years
Storage tank	Large / Rupture	2×10^{-3}	1 in 500 years
Tank Overfill	Production or Loading Rate	4×10^{-3}	1 in 250 years
Tank Boil Over	Boiling oil ejected from tank	1.6×10^{-4}	1 in 6,300 years
Crude Oil Loading/Unloading			
Loading / Unloading	Large / Rupture	1.9×10^{-1}	1 in 5 years
Truck Collision	Major Tank Failure	2.1×10^{-2}	1 in 48 years

5. CONSEQUENCES OF RELEASE

An accidental release of due to equipment failure may present an immediate threat to on and off-site personnel. In the following section, the potential hazards associated with an accidental release will be assessed.

5.1 Material Properties

Material properties from potential production at the Aera Cat Canyon facility have been predicted from well test data, and production data from similar oil fields. These predictions have been used to conduct hazard consequence modeling. A summary of the stream properties used to conduct the consequence modeling are shown in Table 5.1. The following data has been selected to represent the worst case hazards for analysis.

5.1.1 Produced Crude Oil

The heavy bituminous oil will initially have a gravity of 9.0 API, increasing to 7.6 API during peak production. The produced oil will be mixed with about 25% imported light crude oil at the inlet to the Oil Cleaning Plant for treating the crude oil where water and sand will be removed. The concentration of water will be less than 3% after treatment.

The average properties of the treated produced oil are shown in Table 5.1.

5.1.2 Light Crude Oil

Light crude oil with a gravity of about 29 API will be imported for treating the produced oil. On release, the light oil fractions in the crude oil will start to evaporate and may produce a vapor cloud. The vapor cloud will be flammable where the concentration is between the lower and upper flammable limits of 1.4% and 7.8%. On ignition of crude oil, the fire will burn with an orange flame and emit dense clouds of black smoke

5.1.3 Produced Gas

The predicted produced gas composition is shown in Table 5.1. The composition is based on gas sampled from one of the steam pilot wells, and gas from a similar oil field. The H_2S content is predicted to be an average 6%, with a possible range of 1.5% to 10%. A high value of 10% H_2S has been assumed for hazard calculations.

5.1.4 Toxicology of Hydrogen Sulfide

Hydrogen sulfide (H_2S) is a flammable, colorless gas which has the smell of rotten eggs. It is a highly irritant gas that attacks the nervous system and causes respiratory paralysis. At lower concentrations (between 0.2 ppm and 100 ppm by volume) H_2S has the easily recognizable smell of rotten eggs, which alerts people of the need to escape. However, above about 100 ppm the sense of smell is inhibited, and at lethal concentrations hydrogen sulfide cannot be detected by smell.

At concentrations above 1000 ppm, unconsciousness may occur after a single breath, and above 2000 ppm exposure is nearly always fatal after 5 minutes. The toxicological effects of H_2S are summarized in Table 5.2.

5.2 Flammable and Toxic Release Events

A release of liquid or vapor may result in a flammable and/or toxic cloud. The vapor cloud will then disperse to the lower flammable limit, or to a toxic concentration of concern.

A release of flammable liquid and/or gas may result in one or more of several different hazards:

- Immediate ignition causing a jet fire, pool fire, vapor cloud fire or fireball.
- Pool evaporation and initial dispersion of a flammable vapor cloud, which on delayed ignition may result in:
  - vapor cloud fire or
  - vapor cloud explosion
  - confined or spreading liquid pool fire
- Dispersion with no ignition

A release of hot produced fluids under pressure will have significant quantities of water present which will vaporize on release. The steam produced will disperse and dilute the flammable and toxic vapors, making ignition from an uncontrolled well release or gathering line release unlikely.

A release of produced gas will contain up to 10 percent H_2S. A toxic vapor cloud may occur from an uncontrolled well release, gathering line failure, failure at the group separator, or failure at the Produced Gas Treatment Plant. Hydrogen sulfide is heavier than air and can collect in low areas.

An explosion may occur if there is sufficient material within the flammable cloud or partial confinement for the flame front to accelerate. However, due to the unconfined nature of the facility, and low quantities of produced gas, an explosion is unlikely to occur.

The probabilities of ignition are discussed in Section 5.4

5.3 Consequence Modeling

The methodology for calculating the release rates and hazards of a potential release are described in the following section. Published formulas and publicly available dispersion models have been used for the analysis. These methodologies are expected to provide conservative results.

5.3.1 Release Rate Calculations

Release rates were calculated using standard engineering equations for liquid and gas releases. It has been assumed that the releases are essentially continuous, and will develop to the maximum hazard condition before the source is isolated. Where the release rate is greater than the flow feeding the line, the flow rate has been assumed to be the maximum release rate, except for pipeline releases where there is a large inventory in the line.

Gas Release Rate
The equation for estimating the release rate of gas from a hole under choked conditions is provided in the EPA RMP Guidance for Offsite Consequence Analysis[(28)] .

Liquid Release Rate
The release rate of a liquid is calculated as follows using Bernoulli's equation, as provided in the EPA RMP Guidance[(28)] .

Pipeline Release Rate
When a line ruptures, the pressure and release rate decays rapidly over the first minute. The release rate from a fuel gas line failure was calculated over time using the TNO calculation method[(11)].

Pool Evaporation
On release, a liquid will spread to a minimum depth of 1 inch (2.5 centimeters) on a flat non-absorbing surface. If a release is contained, such as in a storage tank dike area, the evaporation rate will be dependent on the surface area of the pool. The evaporation rate was calculated using the method as provided in the EPA RMP Guidance[(28)] and the EPA Technical Guidance for Hazards Analysis[(30)].

5.3.2 Vapor Dispersion

Non-Momentum Ground Level Release
A liquid pool is assumed to produce a continuous evaporating cloud. This cloud will disperse downwind to the Lower Flammability Limit (LFL), unless the cloud is ignited.

For toxic and flammable vapor releases at ground level without significant momentum, the US Environmental Protection Agency and National Oceanic and Atmospheric Administration ALOHA[(31)] model was used. This is a publicly available model and is widely used for estimating release distances. Two types of dispersion may occur; neutrally buoyant and heavy gas release. A neutrally buoyant plume has approximately the same density as air. This model is based on a simple approach described in Turner's Workbook[(24)]. The heavy gas model in ALOHA is based on a simplified form of the DEGADIS model developed by Spicer and Havens (1989).

Elevated Release
Elevated jet releases are vertical gas releases from an elevated vent stack. These have been modeled using the publicly available EPA SCREEN3[(29)] model. This gives predictions of ground level concentrations from an elevated jet using a Gaussian plume model.

5.3.3 Radiation Hazards

Pool Fire Radiation
Liquid releases from a tank, line failure or tank truck were modeled as a circular pool fire with a sooty flame. The soot absorbs radiation and obscures the flame, thereby reducing the thermal

radiation. The pool fire model used is based on publicly available correlations described in the TNO Yellow Book[11].

Fireball Radiation

Intense thermal radiation occurs when a burning fireball is caused by the rapid release of a large quantity flammable material. The radiant heat is calculated from the duration of the fireball and intensity of the radiation.

The calculation method used is the Hymes point-source model as described in the EPA RMP Guidance for Offsite Consequence Analysis[28] .

5.4 Levels of Concern and Vulnerability Criteria

The following levels of concern have been selected as minimum exposure levels that may result in a serious injury or fatality. However, personnel exposed to a minimum level of exposure are not necessarily seriously or fatally injured. Personnel may be sheltered within buildings or cars, or be able to find shelter from exposure. This is called the vulnerability, and is the probability that a person exposed within the distance to a level of concern will suffer a serious injury or fatality.

The thermal radiation or toxic exposures are also not at the same level within the distance to a level of concern. Closer to the fire or release, the vulnerability will be higher. Average vulnerabilities have been estimated within the distance to a fatality level of concern, and between the fatality and serious injury levels of concern.

Vapor Cloud Flash Fire Levels of Concern

A flammable release may be ignited on release or shortly after release if the concentration is in the flammable range between the Lower and Upper Flammability Limits (LFL and UFL). An unignited flammable vapor cloud will drift downwind and start to disperse. It has been assumed that if the release is not ignited immediately, it will not ignite until it has reached its maximum dispersion distance.

However, the concentration levels calculated are time-averaged concentrations, and whether or not the cloud can catch fire at specific location is determined by the instantaneous concentration at a given time. The concentration of vapor in the air is not uniform; there will be areas where the concentration is higher or lower than the average, making escape possible from some area of the cloud.

The duration of a flash fire is short, and those outside the flash fire area are unlikely to be exposed to thermal radiation for sufficient time to cause serious injury. The area of the LFL cloud is assumed to be the hazard zone for potential fatality. The area of 1/2 LFL where a flame may ignite is assumed to be the hazard zone for serious injury.

From incident reports, the extent of burn injury is dependent on clothing. Personnel wearing flame retardant clothing are less likely to suffer severe burns if caught within the flames.

The following average vulnerability levels have been applied.

Severity Level	Flammable Range	Average Vulnerability of People In Vehicles or Buildings	Average Vulnerability of People Outdoors
Potential Fatality	Source to LFL	0.2	0.5
Significant Injury	Source to 1/2 LFL	0.2	0.5

Fire Radiation Levels of Concern

Pool fires and jet fires produce radiant heat, and the effects are dependent on the level of intensity and the duration of exposure. Thermal radiation levels of 5 kW/m^2 and 10 kW/m^2 correspond to approximately the minimum level for serious injury (second degree burns) and potential fatality for exposure up to 40 seconds.

A contained pool fire will typically develop slowly allowing personnel outside the burning pool time for escape. In the event of a spreading pool fire, personnel are assumed to be fatalities if they are within the pool spread area. The following average pool fire vulnerabilities have been applied:

Severity Level	Thermal Radiation Range	Average Vulnerability of People In Vehicles or Buildings	Average Vulnerability of People Outdoors
Potential Fatality	Source to Pool Fire Boundary	0.5	1
Potential Fatality	Source to 10 kW/m^2	0.1	0.3
Significant Injury	Source to 5 kW/ m^2	0.1	0.3

Fireball Radiation Levels of Concern

The minimum thermal radiation “dose” that could cause significant injury is the equivalent to 5 kW/m^2 for a duration of 40 seconds. The minimum thermal radiation “dose” for fatality is the equivalent to 10 kW/m^2 for a duration of 40 seconds. Personnel within the area of the fireball are assumed to be unable to escape. The following average vulnerability levels have been applied:

Severity Level	Flammable Range	Average Vulnerability of People In Vehicles or Buildings	Average Vulnerability of People Outdoors
Potential Fatality	Source to 10 kW/m^2 for 40 seconds	0.1	0.3
Significant Injury	Source to 5 kW/m^2 for 40 seconds	0.1	0.3

Hydrogen Sulfide Toxic Exposure Levels of Concern

The toxicological effects of hydrogen sulfide exposure are shown in Table 5.2. The levels of concern selected for significant injury and potential fatality for exposures of up to an hour are the ERPG-2 and ERPG-3, Emergency Response Planning Guidelines. These are defined by the American Industrial Hygiene Association (AIHA) as follows:

ERPG-2 = 30 ppm — Maximum concentration below which it is believed that nearly all individuals could be exposed for up to one hour without irreversible health effects or impairment of the ability to escape.

ERPG-3 = 100 ppm — Maximum concentration below which it is believed that nearly all individuals could be exposed for up to one hour without life threatening health effects.

Above an exposure level of about 30 ppm, eye and throat irritation becomes more severe, and may cause injury to sensitive population. At exposure levels above about 100 ppm H_2S, the sense of smell is inhibited and people may not be alerted by the rotten eggs odor of the need to escape.

For short duration events, such as a line or vessel failure when the contents may be released in 2 minutes or less, the levels of concern were selected as follows:

700 ppm = — Potential level of fatality for short duration events. Difficulty breathing occurs in 1 to 4 minutes, and may be of concern for sensitive populations.

100 ppm = — Level of significant injury for short duration events. Defined as Immediately Dangerous to Life or Health (IDLH) by NIOSH. Above this concentration the sense of smell is inhibited.

Within a toxic cloud, the following average vulnerability levels have been applied up to the selected levels of concern:

Severity Level	Toxic Range	Average Vulnerability of People In Vehicles or Buildings	Average Vulnerability of People Outdoors
Potential Fatality	Source to 100 ppm	0.1	0.2
Significant Injury	Source to 30 ppm	0.1	0.2

5.5 Calculation of Hazard Distances

Hazard distances for the identified release scenarios have been calculated as described in Section 5.3 to the vulnerability levels of concern defined in Section 5.4 above. These represent the minimum levels for serious injury or fatality.

The following assumptions were made in calculating the hazard distances:

- Two representative weather conditions have been selected for performing the dispersion calculations under worst case and typical conditions; stability F with wind speed 1.5 m/s, and stability D with wind speed 4 m/s.
- A release is assumed to be continuous for the purpose of quantifying the maximum hazard distance.
- Rural conditions have been applied for atmospheric dispersion of vapor clouds.
- Liquid releases are assumed to spill onto a flat non-absorbing surface, and spread to a depth of 1 inch (2.5 centimeters).
- Liquid releases spilled within a dike are contained within the dike area.
- No allowance was made for topography.

Well Failure Hazard Distances

A well failure will result in the release of large quantities of steam. The production gas released will be diluted by the flashing steam to an estimated 1% volume, which is below the lower flammability limit of 4.2%.

The estimated vapor concentration is consistent with recorded experience of well failures with steam stimulated wells in California, where none have been reported to have ignited.

On well failure, the H_2S concentration in will also be significantly diluted by steam. Under worst case conditions, a hazardous concentration of 30 ppm H_2S was estimated to occur at a distance of 18 feet. No hazards to the public were identified.

Hydrogen Sulfide Release from an Unignited Flare

Hydrogen sulfide dispersion modeling has been performed for a worst case release from the emergency flare, assuming ignition failure. The maximum ground level H_2S concentration has been calculated for the worst case weather conditions. The maximum concentration at the nearest residence was calculated as 2 ppm, which may cause eye and throat irritation but is below the level of concern for potential injury.

The results of H_2S dispersion to selected toxic concentrations are shown in Tables 5.3 to 5.5. The results for flammable and fire radiation hazards are shown in Tables 5.6 and 5.7.

5.6 Ignition Probabilities

A flammable release may ignite as soon as the release takes place or some time afterwards when vapors have started to disperse. Ignition may occur immediately as a result of the event causing the release, resulting in a pool fire, flash fire, jet fire, explosion or fireball. If a flammable release does not ignited immediately, a flammable vapor cloud may form and disperse downwind. As the cloud encounters ignition sources, it may ignite causing either a vapor cloud fire or explosion. Ignition may be due to vehicles, electrical equipment, hot surfaces or open flames. Historical data on ignited hydrocarbon releases has been reviewed to estimate the probability of ignition.

5.6.1 Immediate Ignition Probability

The probability of immediate ignition depends on the cause of the release, the size of the gas cloud, and the release material. For a flammable gas or liquid, the TNO Purple Book(10) and Lees publish immediate ignition probabilities depending on the size of the release and flammable cloud

For a large release rapid from a fuel gas pipeline, an immediate ignition may result in a fireball. An immediate ignition probability of 0.1 has been assumed, based on the historical probability of ignition for gas pipelines reported by EGPI(14). In Europe, CONCAWE(12) report that the ignition probability of a large crude oil release at about 4%, mainly due to external impact events.

The likelihood of immediate ignition has been estimated as follows:

Release Size	Probability of Immediate Ignition	
	Gas Release	Crude Oil Release
Medium	0.05	0.025
Large	0.1	0.05

5.6.2 Delayed Ignition Probability

The probability of delayed ignition will depend on the type and number of ignition sources that are encountered by the flammable cloud. Delayed ignition probabilities are provided in the TNO Purple Book(10) and Lees(20) . These provide probabilities of ignition for various sources:

- Fired Heaters = 0.9
- Small Process Facility = 0.45 per site
- Vehicle Ignition = 0.2
- Residential and employee populations = 0.01 per person.

Table 5.1 Stream Properties

Property	Produced Gas	Fuel Gas and Make-up Gas	Light Crude Oil	Treated Produced Crude Oil**
Composition % mol:				
H_2S	1.5 to 10 (avg 6.0)	-		
N_2	2.10	0.31		
CO_2	19.65	3.05		
H_2O	-	-	< 3	< 3
C_1	54.89	89.6		
C_2	2.01	4.57		
C_3	4.14	1.98		
C_4	3.74	0.35		
C_5	4.85	0.12		
C_6 +	2.63	0.02		
Crude Oil			>97	>97
Average properties:				
MW	30.5	18.4		
LFL % mol	4.2	4.8	1.4	1.4
UFL % mol	16.0	14.7	7.8	7.8
RVP @ 100°F			3.5 psi	1.6 psi
Specific Gravity 60/60			0.882	0.986
Specific Gravity (Air=1)	1.05	0.63		
API Gravity			29	12
Ratio of Specific Heats Cp/Cv	1.28	1.30		

** Produced Crude Oil treated with 25% Light Crude Oil to reduce API from 7.6 to 12

Table 5.2 Toxicological Effects of Hydrogen Sulfide

H_2S (ppm)	Potential Effects
0.02 to 0.1	Threshold of smell
0.1 to 30	Increasingly unpleasant rotten eggs odor. Eye and throat irritation.
15	*ACGIH Short-Term Exposure Limit (STEL) for 15 minutes exposure.
30	**ERPG-2 Maximum concentration below which it is believed that nearly all individuals could be exposed for up to one hour without irreversible health effects or impairment of the ability to escape.
100	**ERPG-3 Maximum concentration below which it is believed that nearly all individuals could be exposed for up to one hour without life threatening health effects. ***Immediately Dangerous to Life or Health (IDLH). Maximum concentration from which one could escape without experiencing escape impairing or irreversible health effects.
100 to 300	Loss of sense of smell. Throat and eye irritation within 2 to 15 minutes. Headache, nausea, blurred vision in 30 minutes. Difficulty breathing. Potential loss consciousness after 1 hour.
300 to 700	Difficulty breathing within 1 to 4 minutes. Collapse, unconsciousness within 15 minutes. May be fatal over about 30 minutes exposure.
700 to 1,000	Coughing, collapse and unconsciousness. May be fatal within several minutes.
1,000 to 2,000	Unconsciousness within 2 minutes, respiratory failure and death if not revived promptly.
2,000 +	Unconsciousness almost immediately. Respiratory failure and death within 5 minutes.

* American Conference of Governmental Industrial Hygienists (ACGIH)

** ERPG levels are Emergency Response Planning Guidelines, developed by the American Industrial Hygiene Association (AIHA). These were specifically developed for emergency response planning, and have been adopted by the U.S. Environmental Protection Agency (EPA) to identify levels of concern for hazardous chemicals.

*** IDLH levels are published by the National Institute for Occupational Safety and Health (NIOSH). The IDLH is considered a maximum concentration above which only a highly reliable breathing apparatus is permitted.

Table 5.3 Toxic Vapor Dispersion from Ground Level Release

Release Source	Release Rate (lb/min)	Weather Conditions*	Downwind Distance to Toxic Concentration from Release (ft)	
			100 ppm ERPG-3	30 ppm ERPG-2
Well Failure				
Well “blowout”	1200	F/1.5	-	-
	(estimated initial flow)	D/4	-	18
Gathering Line Releases				
Large / Rupture 8-inch line	3.1 H_2S	F/1.5	340	620
	5628 gas+liquid	D/4	75	140
Large / Rupture 6-inch line	1.6 H_2S	F/1.5	230	440
	2814 gas+liquid	D/4	50	100
Large / Rupture 3-inch line	0.4 H_2S	F/1.5	90	150
	678 gas+liquid	D/4	20	40

* Weather conditions D stability, 4 m/s wind (typical conditions during the day), and F stability 1.5 m/s wind (worst case weather conditions at night).

Table 5.4 Toxic Vapor Dispersion from Short Duration Events

Release Source	Release	Weather Conditions*	Downwind Distance to Toxic Concentration from Release (ft)	
			700 ppm Fatality	100 ppm Injury
Group Separator / Line Failure				
Line failure / Rupture of Separator Vessel	19 lb H_2S	F/1.5	670	1400
		D/4	160	430
Sour Gas Treating Vessel / Line Failure				
Line failure / Rupture of Vessel	8 lb H_2S	F/1.5	440	1000
		D/4	100	270
TVR Gas Transfer Line				
Large / Rupture 4-inch line	10 lb H_2S	F/1.5	500	1100
		D/4	110	310

* Weather conditions D stability, 4 m/s wind (typical conditions during the day), and F stability 1.5 m/s wind (worst case weather conditions at night).

Table 5.5 Toxic Vapor Dispersion from Elevated Releases

Release Source	H_2S Release Rate (lb/min)	Distance from Release (ft)	Weather Stability / Wind (m/s)	H_2S Concentration**
Unignited Emergency Flare (Maximum H_2S Flow)	6	460	C / 1	21 ppm (maximum)
		1,100 (to non Aera Well Pad)	D / 1	17 ppm
		2,000 (to fenceline)	D / 1	9 ppm
		4,600 (nearest residence)	F / 1	2 ppm

** Maximum ground level concentration under worst case weather conditions.

Note: No ground level concentrations of H_2S were identified for serious injury.

Table 5.6 Flammable Vapor Dispersion

Release Source	Release Rate / Pool Evaporation Rate (lb/min)	Weather Conditions*	Distance to Flammable Concentration from Release (ft)	
			LFL	1/2 LFL
TVR Gas Line				
Large hole / Rupture	55	F/1.5	20	30
(momentum release)	(1 min average)	D/4	20	30
Fuel Gas Line				
Large hole / Rupture	710	F/1.5	85	200
(momentum release)	(1 min average)	D/4	85	200
Crude Oil Storage Tank				
Light Crude Release to	290	F/1.5	180	260
dike and containment	630	D/4	140	200
Blended Crude Release	650	F/1.5	300	430
to dike and containment	1,400	D/4	200	310
Crude Oil Loading / Unloading Truck Release				
Light Crude Release to	140	F/1.5	120	170
pavement	300	D/4	90	140
Blended Crude Release	310	F/1.5	190	280
to pavement	670	D/4	140	220

* Weather conditions D stability, 4 m/s wind (typical conditions during the day), and F stability 1.5 m/s wind (worst case weather conditions at night).

Table 5.7 Fire Radiation Hazards

Release Source	Release Rate	Weather Conditions*	Hazard Distance from Release (ft)	
			Fatality**	Injury**
Fuel Gas Line				
Large hole (jet fire)	710 lb/min (1 min average)	F/1.5	85	200
		D/4	85	200
Rupture (fireball)	710 lb	F/1.5	140	200
		D/4	140	200
Crude Oil Storage Tanks				
Release to Dike	Dike area = 11,000 ft^2	F/1.5	110	160
		D/4	180	240
Crude Oil Loading / Unloading Truck Release				
Crude Release to Pavement	Average pool depth = 1-inch	F/1.5	110	160
		D/4	170	230

* Weather conditions D stability, 4 m/s wind (typical conditions during the day), and F stability 1.5 m/s wind (worst case weather conditions at night).

** Pool fire and jet fire radiation hazards:
Potential fatality = 10 kW/m^2
Potential injury = 5 kW/m^2
Fireball radiation hazards:
Potential fatality = equivalent dose of 10 kW/m^2 for 40 seconds
Potential injury = equivalent dose of 5 kW/m^2 for 40 seconds

6. SOCIETAL RISK PROFILE

6.1 Hazardous Release Event Trees

Incident event trees have been used calculate the outcome of each potential release event. The potential for damage, and the extent of damage, will depend on the release location, likelihood of rapid detection, response and weather conditions at the time of the incident. These have been analyzed by identifying potential release events that may impact public populations, and summating the likelihood that the hazard will occur for each scenario. An example incident event tree is shown in Figure 6.1

6.2 Calculation of Societal Risks

The risks to on and off-site public populations have been calculated and summated as societal risk. For each release scenario, the potential number of serious injuries or fatalities is calculated from the area that may be impacted, the wind direction (as appropriate), the probability of ignition, number of people within the impacted area, and then applying a vulnerability based on if the populations are inside or outside a building.

The risk has been calculated for each potential release source using the following equation:

Likelihood of release X Probability of serious injury or fatality = Risk

Societal risks have been presented as F-N curves, also called the risk profile. F-N curves are a plot of the cumulative frequency (F) of an event against the number of N or more potential serious injuries or fatalities.

6.3 Significance of Societal Risk

Santa Barbara County requires an assessment of the significance of impacts to public safety associated with an application for a land-use permit. Thresholds for the acceptability of risk of fatality or serious injury to the public are defined by the SBC societal risk criteria[22]. These thresholds provide three zones of significance; green, amber and red, for determining the acceptability of involuntary public exposure to acute risks resulting from new or modified developments. The three zones are defined as follows and shown on the societal risk profiles in Figures 6.2 and 6.3:

- Green: Less than significant impact to public safety and no mitigation (or additional mitigation) is required for purposes of compliance.
- Amber: Potentially significant public impact, which can be reduced or avoided by implementation of mitigation measures
- Red: Significant public impact, which can be reduced by implementation of mitigation measures

Mitigation measures may be applied to an identified adverse but not significant impact to mitigate the impact to the maximum extent practicable.

6.4 Conclusion and Public Risk Profiles

The QRA results in an insignificant impact to public safety; i.e., Green zone, and no mitigation is required for purposes of compliance. Refer to Figures 6.2 and 6.3.

Mitigations incorporated in the Project conceptual design include the following:

- Vehicle impact protection at piping and well sites
- Truck flow and loading rack supervision for loading and unloading crude oil
- Site security and video surveillance

These mitigations were not taken into consideration for determining this QRA and Public Risk Profiles. These design features will decrease the Project Risk Profile shown in Figures 6.2 and 6.3.

Figure 6.1 Example Event Tree for Flammable / Toxic Gas Release

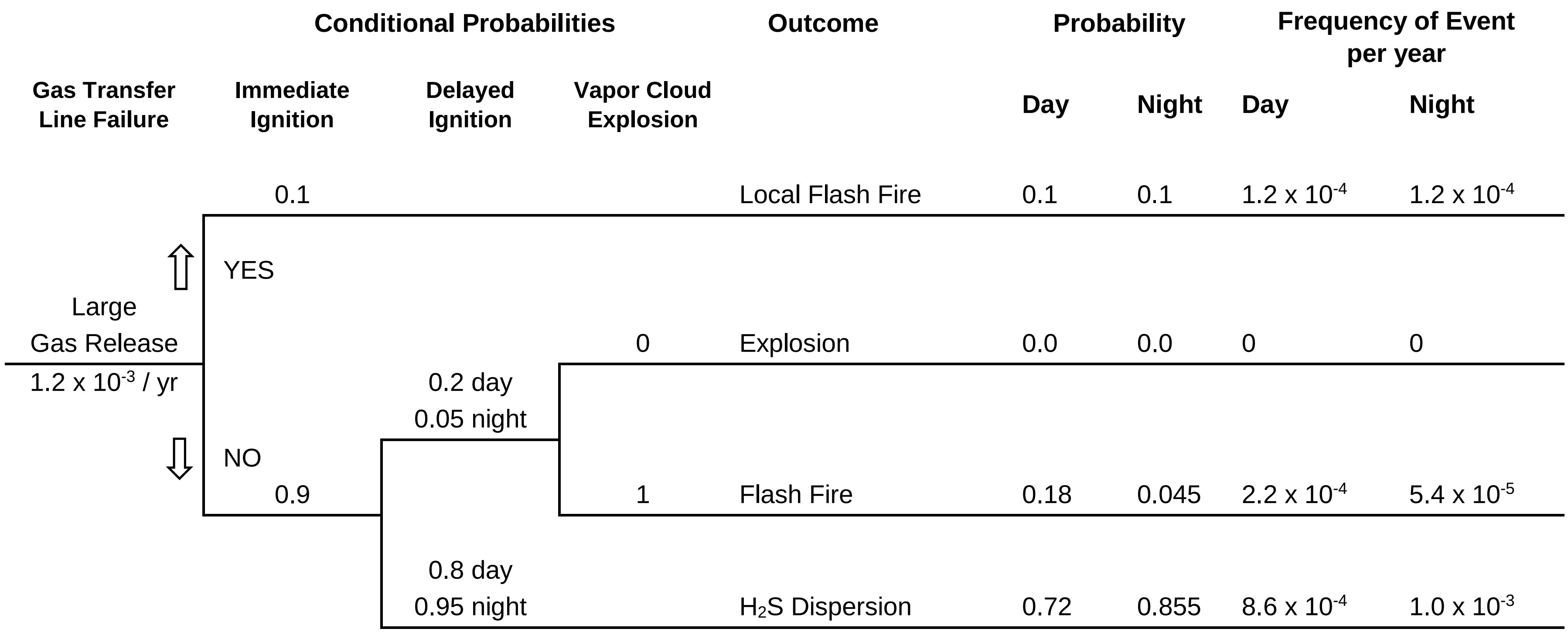


Figure 6.2 Public Risk of Injury Profile

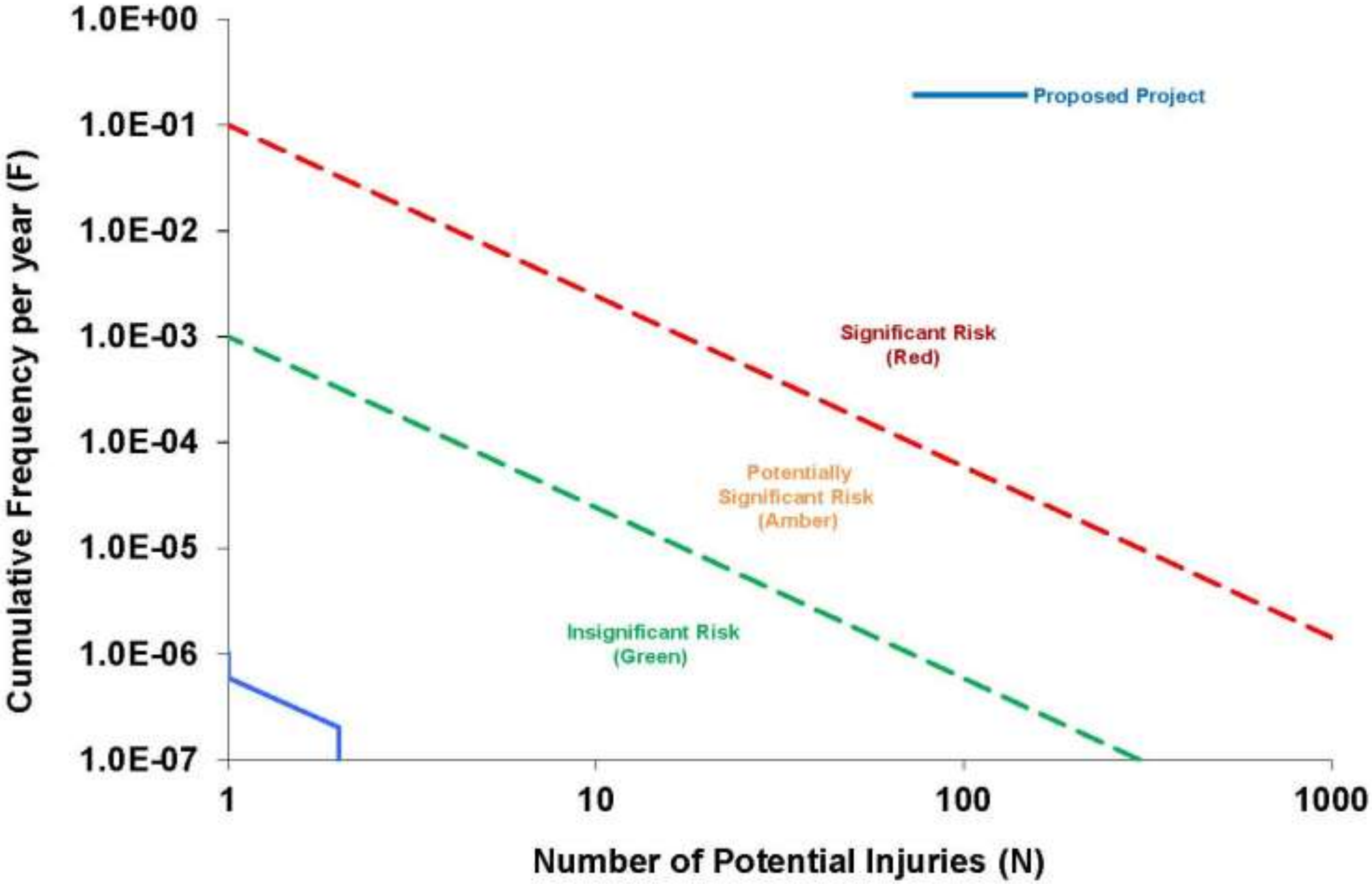
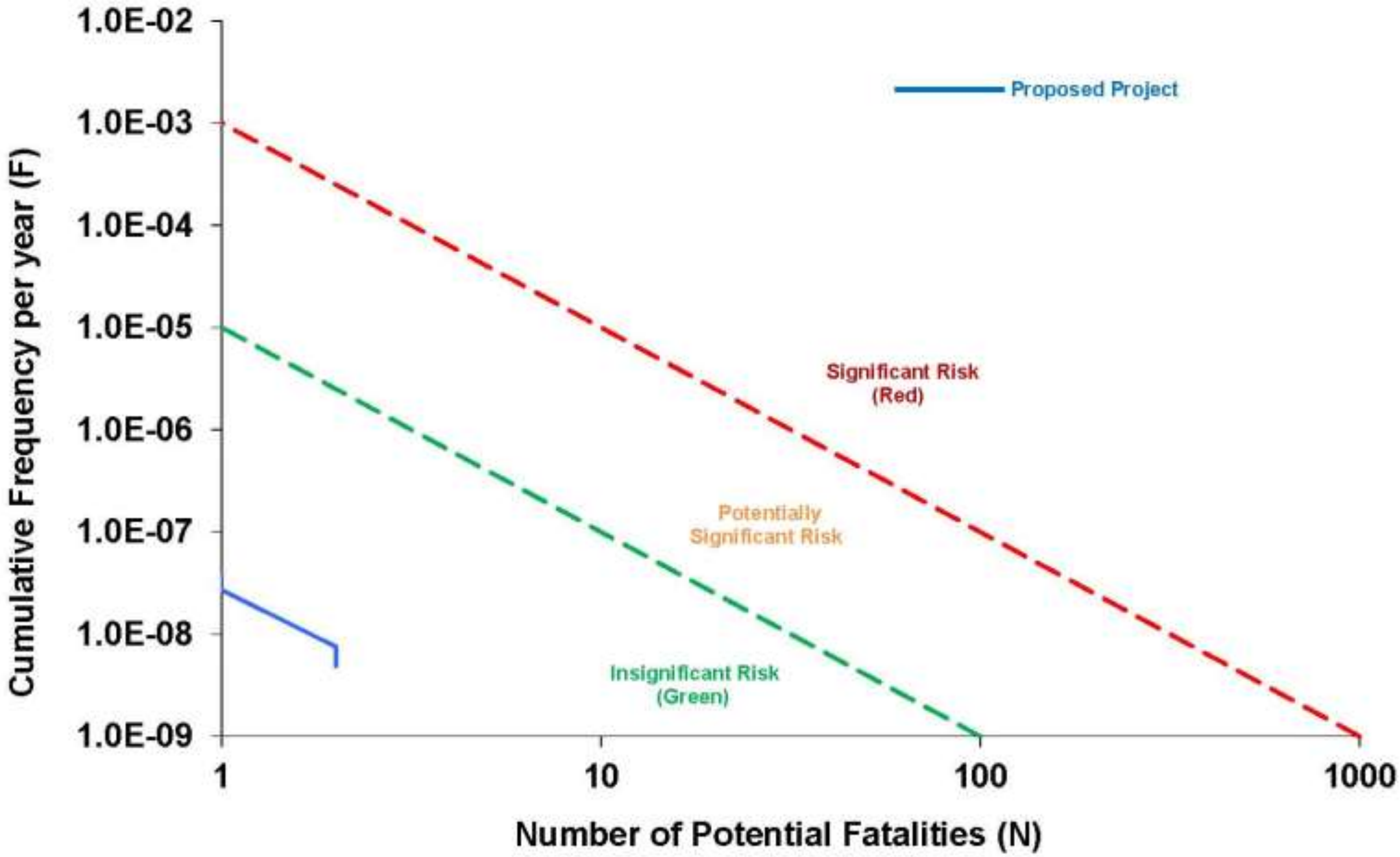


Figure 6.3 Public Risk of Fatality Profile



7. REFERENCES

(1) Alberta Energy Utilities Board, "Pipeline Performance in Alberta – 1980 to 1997", Report 98-G December 1998.

(2) American Petroleum Institute, "The Safety of Interstate Liquid Pipelines", 1987.

(3) Association of Oil and Gas Producers, "Safety Performance Report", 1997.

(4) Arthur D. Little, "Risk Assessment for Gas Liquids Transportation From Santa Barbara County", Prepared for Santa Barbara County 1990.

(5) California Department of Conservation, Division of Oil, Gas and Geothermal Resources, "A History of Oil and Gas Well Blowouts in California", 1993.

(6) California State Fire Marshal, "An Assessment of California Low-Pressure Crude Oil Pipelines and Crude Oil Gathering Lines", April 1997.

(7) California State Fire Marshal, "Hazardous Liquid Pipeline Risk Assessment", April 1993.

(8) Center for Chemical Process Safety of the AIChE, "Guidelines for Chemical Transportation Risk Analysis", 1995.

(9) Center for Chemical Process Safety of the AIChE, "Guidelines for Process Equipment Reliability Data", 1989.

(10) Committee for the Prevention of Disasters (CPR), "Guidelines for Quantitative Risk Assessment – TNO Purple Book", CPR-18E, The Hague, 1999.

(11) Committee for the Prevention of Disasters (CPR), "Methods for the Calculation of Physical Effects due to Releases of Hazardous Materials – TNO Yellow Book", CPR-14E, The Hague, 1996.

(12) CONCAWE, "Performance of European Cross-Country Oil Pipelines" Report No. 12/13 December 2013.

(13) Exploration and Production Forum, "Hydrocarbon Leak and Ignition Database", Report No. 11.4/180, 1992.

(14) European Gas Pipeline Incidents, "Report to the European Gas Pipeline Incident Data Group", 7th Report 1970-2007.

(15) FEMA, "Handbook of Chemical Hazard Analysis Procedures", 1989.

(16) Haines S.W., “Large Diameter Tank ire Incident Database,” API Conference South Carolina, September 1995.

(17) Harwood, Vinner and Russell, “Truck Accident and Release Rates for HAZMAT Routing,” National Conference on Hazardous Materials Transportation, 1992.

(18) Jones D.J. et al., “An Analysis of Reportable Incidents for Natural Gas Transmission and Gathering Lines 1970 Through 1984”, American Gas Association, 1986.

(19) Jones D.J. and Eiber R.J., “An Analysis of Reportable Incidents for Natural Gas Transmission and Gathering Lines 1984 Through 1989”, American Gas Association, 1990.

(20) Lees F.P., Loss Prevention in the Process Industries, 1996.

(21) Salzano E., Iervolino I., Fabbrocino G., “Seismic Risk of Atmospheric Storage Tanks in the Framework of Quantitative Risk Analysis”, Journal of Loss Prevention in the Process Industries, 2003, p403-409.

(22) Santa Barbara County, “Environmental Thresholds and Guidelines Manual,” October 2008.

(23) Smith T.A. and Warwick R.G., “A Survey of Defects In Pressure Vessels in the UK for the Period 196201778 and its Relevance to Nuclear Primary Circuits”, UKAEA SRD Report R203, 1981.

(24) Turner, D. Bruce, “Workbook of Atmospheric Dispersion Estimates: An Introduction to Dispersion Modeling”,1974.

(25) UK Health and Safety Executive, “Failure Rate and Event Data for use Within Risk Assessments”, May 2012.

(26) US Atomic Energy Commission, “Reactor Safety Study – An assessment of Accidental Risks in the U.S. Commercial Nuclear Power Plants”, WASH-1400, 1975, Appendix III “Failure Data”.

(27) US Environmental Protection Agency, “Results of 1995 Survey of Oil Storage Facilities”, July 1996.

(28) US Environmental Protection Agency, “Risk Management Program Guidance for Offsite Consequence Analysis”, April 1999.

(29) US Environmental Protection Agency, SCREEN3, Computer Program, Version 96043

(30) USEPA, FEMA and USDOT, “Technical Guidance for Hazards Analysis”, December 1987.

(31) US Environmental Protection Agency and National Oceanic and Atmospheric Administration, Areal Locations of Hazardous Atmospheres (ALOHA), Computer Program, Version 5.4.4.

(32) US Geological Survey, "National Seismic Hazard Maps", accessed from website earthquake.usgs.gov/hazards, 2008.