P1203

BERCHA GROUP

FINAL REPORT

E&B Oil Development Project
Quantitative Risk Analysis

For:

E&B Natural Resources Management Corporation
Bakersfield, California, USA

By:

Bercha International Inc.
Calgary, Alberta, Canada

July 3, 2013

EXECUTIVE SUMMARY

A. Principal Results and Conclusions

The principal results include annual individual and collective risks, as well as cumulated risks over the E&B Oil Development Project (the Project) life. Table 1 summarizes the principal results, including risk acceptability according to the individual and collective public risk thresholds adopted for the Project. From Table 1, it can be concluded that all risks to the public are acceptable, as they are in the Insignificant risk region for both Phases 2 and 4, the operational phases of the Project. In addition, the offsite risks to the environment from the oil trucking operations in Phase 2 and the oil pipeline operation in Phase 4 were quantified in terms of the probability and maximum value of a possible oil spill, and were found to pose Insignificant environmental risk. Spill risks from both phases were found to be Insignificant. In order to provide some context on the individual risk values, a bar chart showing common accidental individual specific risks to North Americans, as well as the maximum annual Project risk, is shown in Figure 1 in units directly comparable to the "Maximum Value (in 1 million)" column in Table 1.

Table 1: Summary of Hermosa Beach Oil Development Project Public Risks

PHASE	TYPE OF RISK	MAXIMUM VALUE	MAXIMUM VALUE (in 1 million)	ACCEPTABILITY	KEY DESIGN FEATURES INCLUDED
2	Maximum offsite resident annual individual specific risk	1 in 1 billion	0.001	Insignificant	• Industry standard measures • Automatic isolation valves • Perimeter wall
	Annual public collective risk of 1 or more fatalities	1 in 100 million	0.01	Insignificant	
	Annual public collective risk of 10 or more fatalities	zero	0.0	Insignificant	
4	Maximum offsite resident annual individual specific risk	1 in 100 million	0.01	Insignificant	• Industry standard measures • Automatic isolation valves • Perimeter wall
	Annual public collective risk of 1 or more fatalities	1 in 1 million	1.0	Insignificant	
	Annual public collective risk of 10 or more fatalities	6 in 100 million	0.06	Insignificant	
	Cumulative 35 year resident individual specific risk	4 in 10 million	0.4	Insignificant	

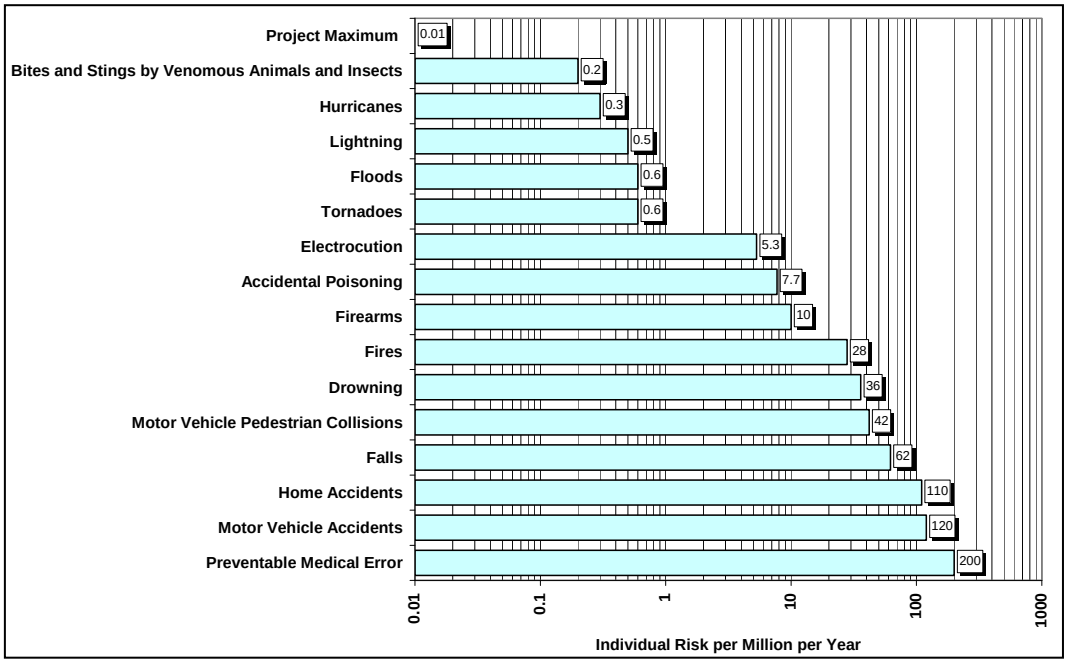


Figure 1: Comparative Annual Individual Specific Risks of Fatality per Million

B. Background

E&B Natural Resources Management Corporation (E&B) is proposing the development of the E&B Oil Development Project (the Project) on a site within the City of Hermosa Beach. The Project provides for the development of an onshore drilling and production facility that would utilize directional drilling techniques to access crude oil and natural gas reserves in the tidelands granted by the State of California to the City, and in an onshore area known as the "uplands". The Project is divided into four phases as follows:

- Phase 1: Site Preparation
- Phase 2: Drilling and Testing
- Phase 3: Final Design and Construction
- Phase 4: Development and Operations

Only Phases 2 and 4 are dealt with in this report, because these are the only phases which include hydrocarbon drilling and production operations.

To support the design and regulatory process, E&B has commissioned Bercha International Inc (Bercha) to carry out a quantitative risk analysis (QRA) to assess public safety and environmental risks resulting from the Project. The public QRA considers only acute risks to people; it does not cover chronic health risks. The environmental QRA only considers acute environmental risks offsite.

C. General Description of the Work Completed

The work was carried out utilizing standard techniques of risk analysis, including data acquisition, hazard scenario development, frequency and consequence analysis, and risk assessment, as well as the evaluation of risk acceptability utilizing generally accepted individual and collective risk thresholds. In addition, risk mitigation measures applicable to the Project were presented and discussed.

D. General Description of Results

Both individual and collective risks were evaluated. Acceptability of public individual specific risks is determined from the 1 in 1 million per year criterion; at or above 1 in 1 million the risk is deemed Significant; below, it is deemed Insignificant. Collective risks are measured against the Santa Barbara Collective Risk thresholds. Environmental risks were evaluated using the Santa Barbara Environmental Risk Matrix.

Figure 2 shows a plot of the resident individual specific risks for Phase 2. It can be seen that the maximum offsite risk is 10^{-9} or 1 in 1 billion, a value very close to zero.

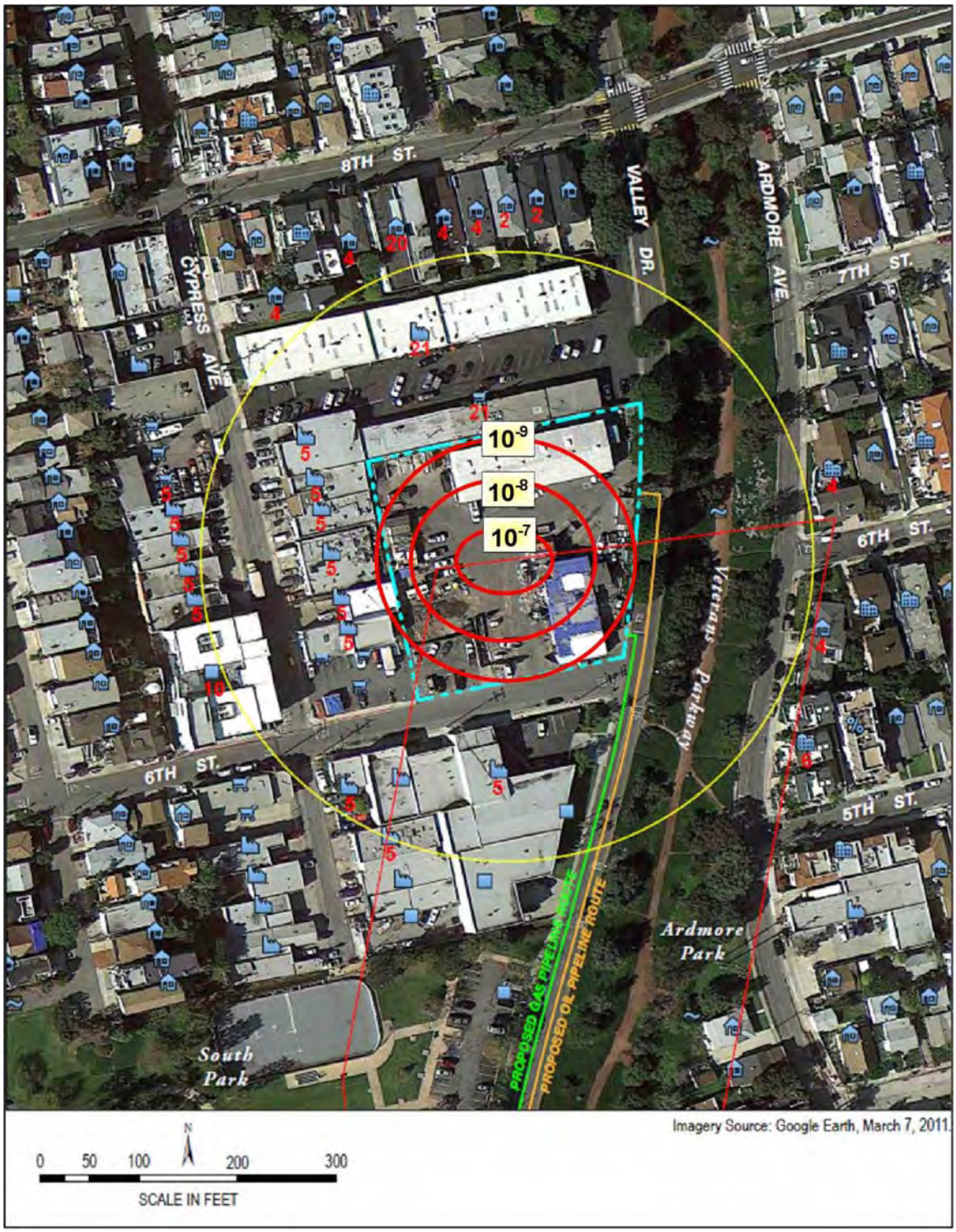


Figure 2
Phase 2 Resident Individual Specific Risk Contours

The collective risks (the red line) plotted with the collective risk thresholds (indicated by the diagonal straight lines) are shown in Figure 3. It can be seen that the Phase 2 plot is entirely in the Insignificant region. Hence, all public risks for Phase 2 are Insigificant, and hence acceptable.

Phase 4 is the dominant phase as it is proposed to operate for approximately 35 years, and entails significantly more facilities than Phase 2. Figure 4 shows the resident individual specific risk contours for Phase 4, which are all below 1 in 1 million offsite, and much lower below 1 in 100 million (10^{-8}) at the nearest residential locations. Figure 5 shows the Phase 4 collective risk, integrated for the process facility and the natural gas pipeline, again plotted with the collective risk thresholds. It can be seen that the collective risks from Phase 4 are all in the Insignificant region. Thus, all Phase 4 individual and collective risks are in the Insignificant region, and therefore acceptable.

Environmental risks for the transportation of oil by trucks in Phase 2 and by pipeline in Phase 4 were also assessed and found to be in the Insignificant region using the Santa Barbara Environmental Risk Matrix.

Only the key risk mitigation measures identified as “Key Design Features” in Table 1 were explicitly quantified in this risk analysis, although numerous additional risk reduction measures are included but not quantified. Thus, the risks as reported here are larger than those expected. However, as the risks are all Insignificant, quantification of these additional measures would only show that the risks are even lower, but still Insignificant. It can be concluded that all risks from the Project are in the Insignificant region, and therefore acceptable.

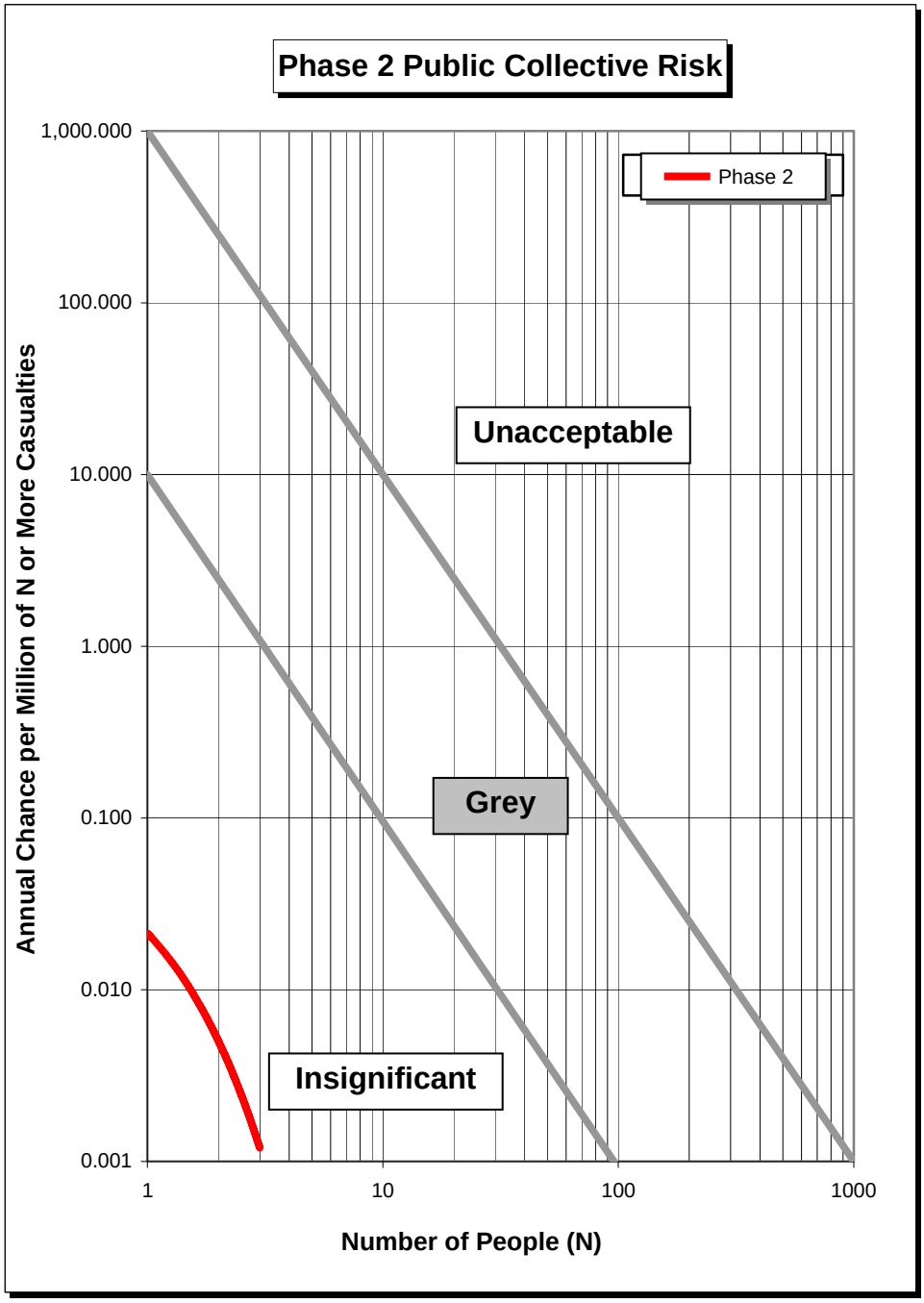


Figure 3
Phase 2 Public Collective Risk

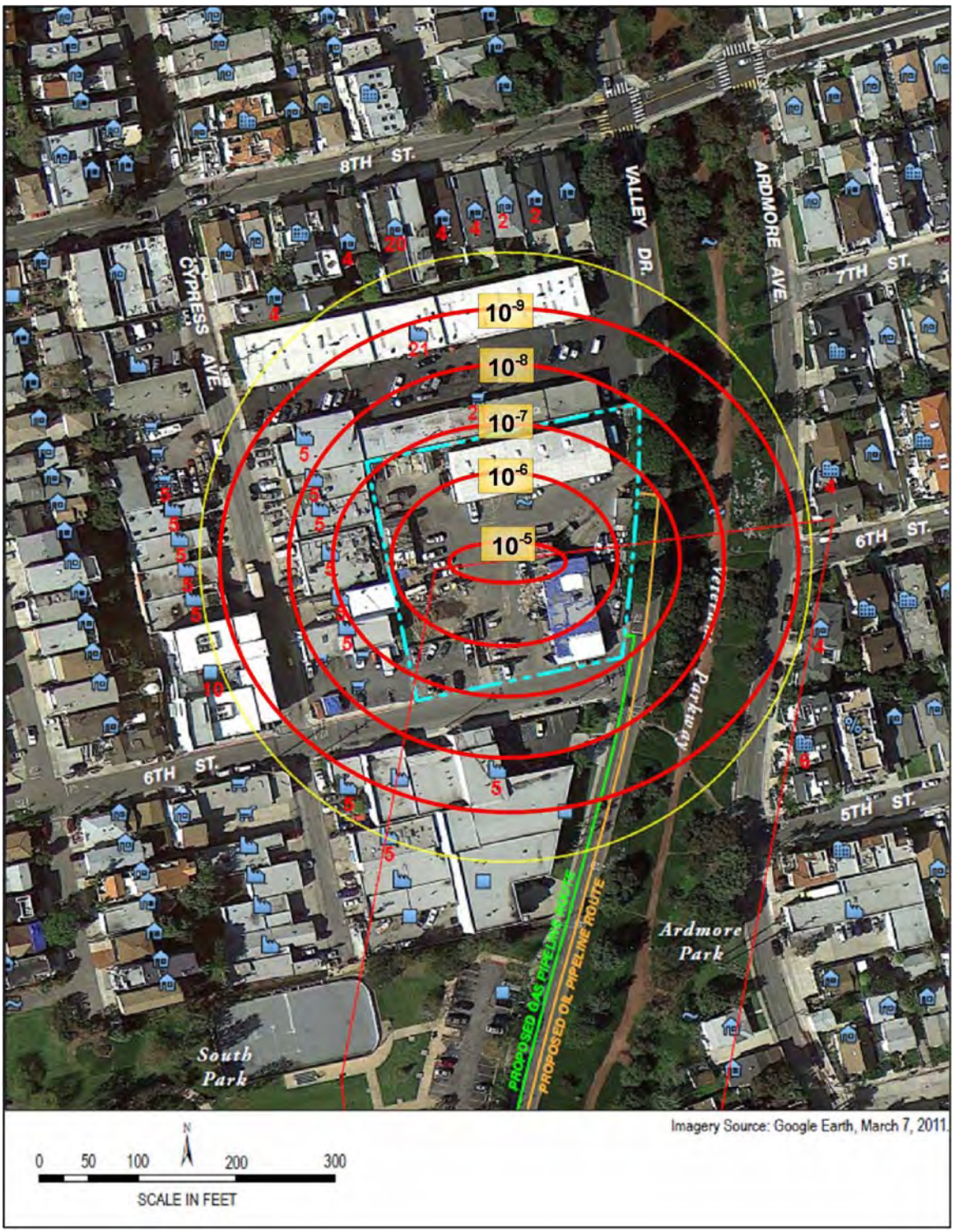
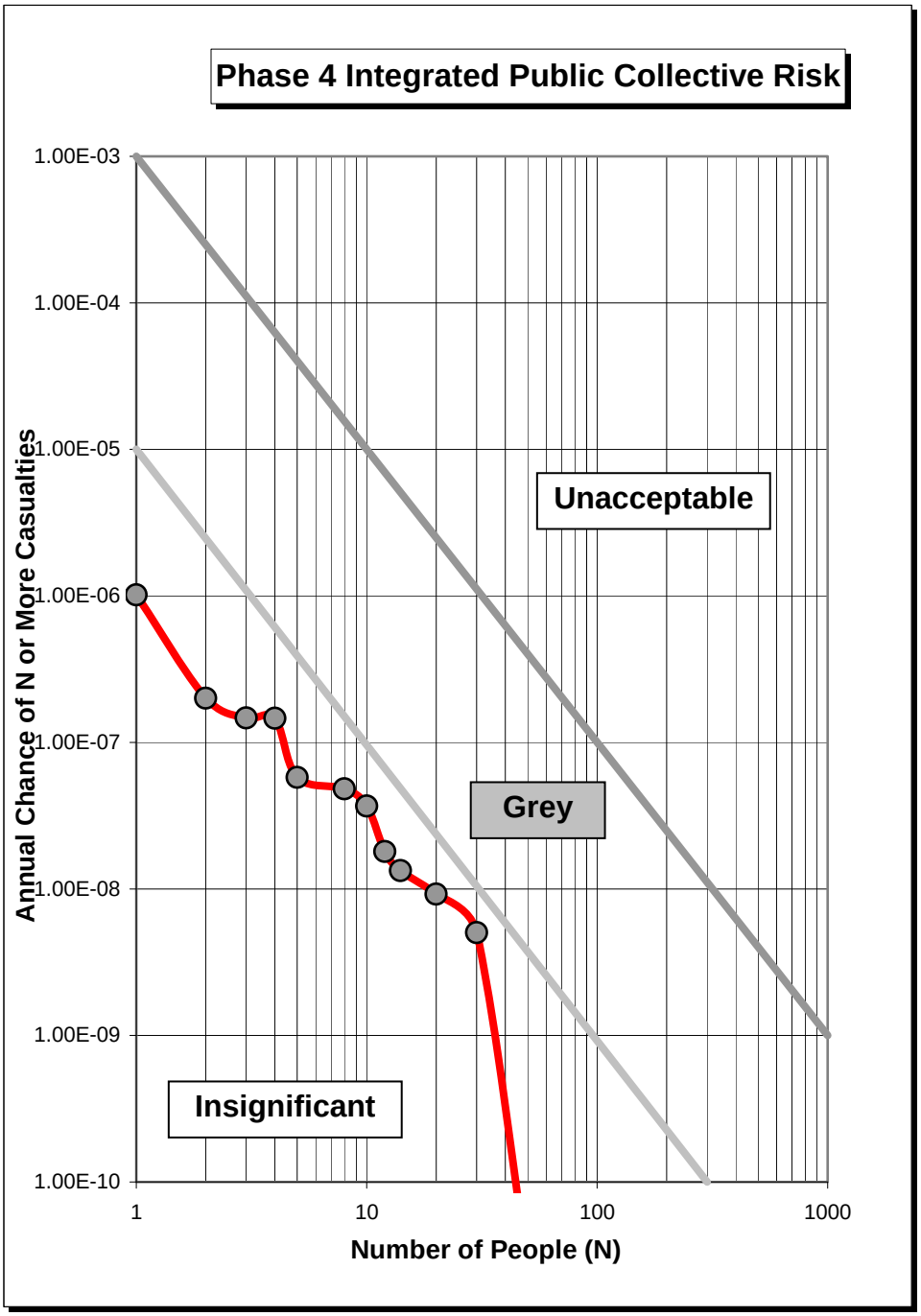


Figure 4
Phase 4 Resident Individual Specific Risk Contours



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GLOSSARY OF TERMS AND ACRONYMS

Acute Risk = Risk that has an immediate adverse effect due to a single exposure to an accident such as a gas explosion.

AOF = Absolute Open Flow

AIChE = American Institute of Chemical Engineers

Blowout = Uncontrolled flow of well fluids to the atmosphere

BRISC = Bercha Risk Integration Software Capability

Casualty = Fatality or severe injury

Chronic Risk = Risk that has adverse effect due to a long-term series of exposures

CBA = Cost Benefit Analysis

CSFM = California State Fire Marshall

Collective Risk = Risk to a specific number of people, quantified as the risk to N or more people.

EPA = United States. Environmental Protection Agency

ESD = Emergency Shutdown

ESDV = Emergency Shutdown Valve

Hazard = A condition with a potential to create risks such as accidental leakage of natural gas from a pressurized vessel

IRI = Individual Risk, annual risk to an individual located at a specific location continuously for one year (24 hrs/day, 365 days/yr) as a result from a nearby project or facility

ISR = Individual Specific Risk, the actual risk per year to an individual resulting from a specific facility or project considering the actual time and exposure by the individual in the zone of influence of the project

MOP = Maximum Operating Pressure, the highest pressure at which a pipeline can be operated

Natural Gas = Hydrocarbons which are used as a source of energy and normally are in a gas phase at standard conditions of pressure and temperature

NGL = Natural Gas Liquids

OISR = Outdoor Individual Specific Risk

P&ID = Piping & Instrumentation Diagram

PFD = Process Flow Diagram

PHMSA = Pipeline and Hazardous Materials Safety Administration

PRV = Pressure Relief Valve

Public Safety = Protection of the general public from acute, immediate effects caused by a single exposure to an accident resulting in severe injury or fatality.

Risk = A compound measure of the probability and magnitude of adverse effect.

Risk Spectrum = A graphical depiction of a cumulative distribution relating probability and number of casualties.

ROO = Ratio of Occurrence

Sour Gas = Natural gas containing significant amounts of hydrogen sulfide (generally more than 50 ppm)

Sweet Gas = Natural gas with no significant amounts of hydrogen sulfide

TRACE = A multi-purpose consequence analysis software modeling system developed by DuPont and sold by Safer Systems

CHAPTER 1

INTRODUCTION

1.1 General Introduction

E&B Natural Resources Management Corporation (E&B), the Applicant, is proposing the E&B Oil Development Project (the Project) on a 1.3-acre site located at 555 6th Street in the City of Hermosa Beach. The Project site is bounded on the east by Valley Drive and on the south by 6th Street, approximately seven blocks to the east of the beach and the Pacific Ocean. The Project site, delineated by the dotted line in Figure 1.1, is owned by the City and is currently used as their City Maintenance Yard.

The Project provides for the development of an onshore drilling and production site that would utilize directional drilling techniques to access the crude oil and natural gas reserves in the tidelands granted by the State of California to the City and in an onshore area known as the uplands. A natural gas pipeline following a route within Valley Drive south of the facility site, shown in Figure 1.2, is proposed to export produced natural gas. The Project would utilize the latest technology and operational advancements related to safety and efficiency in order to provide an oil and natural gas development project that would be accomplished safely and provide benefits to the community.

The Project is divided into four phases as follows:

- Phase 1: Site Preparation
- Phase 2: Drilling and Testing
- Phase 3: Final Design and Construction
- Phase 4: Development and Operations

Only Phases 2 and 4 are dealt with in this report, because these are the only phases which include hydrocarbon drilling and production operations.

To support the design and regulatory process, E&B has commissioned Bercha International Inc. (Bercha) to carry out a quantitative risk analysis (QRA) to assess public safety in the vicinity of the Project. The public QRA considers only acute risks to people; it does not cover chronic health risks, while the environmental QRA only considers acute environmental spill risk along oil transportation routes. This Final Report is intended to provide information on all aspects of the QRA.

1.2 Objective of this QRA

The general objectives of this QRA can be summarized as follows:

(a) To identify potential hydrocarbon release offsite acute hazard scenarios at the proposed facilities and along the hydrocarbon transportation routes.

(b) To conduct a QRA to assess public and environmental risks from such acute hazard scenarios.

(c) To review potential risk mitigation measures.

(d) To assess the acceptability of the individual and collective risks to the public.

(e) To assess the offsite oil spill potential.

Figure 1.1
Facility Site

Figure 1.2
Pipeline Route

1.3 The Risk Analysis Process

What is risk? **Risk** is a compound measure of the probability and magnitude of adverse effect. That is, risk is a description of the chances of something bad happening and how bad it will be. It is important to keep in mind that there are always these two elements of risk; namely, the probability or likelihood and the size or magnitude of the associated damage or loss. An example risk is a probability of 1 in 1 million per year of a specific individual casualty.

Risk Analysis is an orderly process through which one can assess risk as well as methods of reducing the risk [12]*. When the risk analysis quantifies risks it is called Quantitative Risk Analysis (QRA). The five principal steps and various sub-steps of the Risk Analysis process are illustrated in Figure 1.3. The five principal steps are **Hazard Definition**, **Frequency Analysis**, **Consequence Analysis**, **Risk Assessment,** and **Risk Mitigation**.

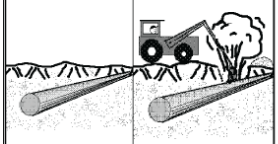
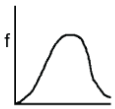
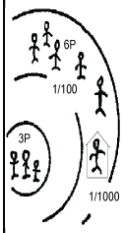
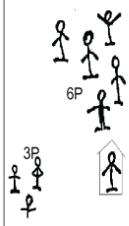
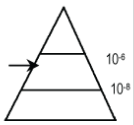
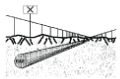
STEP	HAZARD DEFINITION		FREQUENCY ANALYSIS	CONSEQUENCE ANALYSIS		RISK ASSESSMENT			RISK MITIGATION
	SYSTEM DATA	SCENARIO DEVELOPMENT	FREQUENCY ASSESSMENT	DAMAGE CRITERIA	EFFECT FOOTPRINTS	RECEPTORS	RISK EVALUATION	RISK ACCEPT-ABILITY	RISK MITIGATION
QUESTION	WHAT IS IT?	WHAT CAN HAPPEN?	HOW OFTEN?	HOW DANGEROUS?	WHERE/WHEN IS THE DANGER?	WHO CAN BE AFFECTED?	HOW LIKELY AM I TO BE AFFECTED?	IS THE RISK ACCEPTABLE?	WHAT CAN BE DONE TO REDUCE THE RISK?
EXAMPLE	 BURIED **CRUDE OIL** PIPELINE	LOSS OF CONTAINMENT	 • AEUB statistics					 RISK PYRAMID	 • ROW control • Monitoring
STUDY PROCESS	System parameters	Hazard scenario definition	• Statistics • Fault trees	Susceptibility to: • Thermal • Overpressure • Toxic effects	Prediction of dispersion or ignited gas behavior	Population distribution (time/location)	Combine results of all previous steps	Evaluation of risks	Mitigation Evaluation
RESULT	Problem input quantification	Size, time, orientation, description	• Frequency • Orientation • Magnitude • Duration	Critical levels	Damage map isopleths	Time/space distribution	Individual and Collective Risk	Risk Tolerance / Intolerance	Residual Risk

Figure 1.3
The Risk Analysis Process

In **Hazard Definition**, essentially one determines the characteristics of the situation (**System Data**) which can pose a danger to the public, and how the danger is likely to come about. The latter is called **Hazard Scenario Development.** For example, in Scenario Development, for the case of a natural gas pipeline, we would assess the ways in which the pipeline can fail, and how much hazardous material could be released.

* Numbers in square brackets correspond to publications listed in the References section of this report.

In **Frequency Analysis** one determines how often it can happen. Thus, we assess how often the accident is likely to happen, in terms of number of accidents per year or per million years.

In **Consequence Analysis**, one models the consequences. First one finds the relative likelihood of different outcomes of the release, using event trees. This is called **Consequence Evolution**. That is, for the natural gas release, what is the relative likelihood of ignition and non-ignition? And if ignition happens, what are the **Damage Criteria**, or levels of effect which can cause harm. Next, by quantifying hazard distances, one maps the **Hazard Footprints** or **Effect Footprints** in which damage to people could occur if they were present.

In the **Risk Assessment**, the results of the hazard analysis and the consequence analysis are melded with the presence of people or **Receptors**, in areas where they could be hurt and at the times when such damaging events could occur. The results are then integrated into **Risk Evaluation** to provide measures of risk. Measures of risk to people are primarily **Individual Risk** and **Collective Risk**. The **Risk Acceptability** is then investigated by comparison to regulatory or community-used risk thresholds and discussion with stakeholders.

Finally, if the risks are of concern, the proactive portion of the risk analysis is performed through the definition of ways of reducing the risks and assessing just how much risk reduction can be achieved if different **Risk Mitigation** measures are applied. Following the definition of risk mitigation measures, and their effect on the unmitigated risk, the residual or mitigated risk results for both individual and collective risk can be assessed.

The risk analysis process described above typifies the steps in assessing acute risk to people and the environment; assessment of chronic or long-term cumulative risks follows a similar pattern but employs somewhat different terminology within a toxicological framework. Assessment of chronic risks is not within the scope of this risk analysis.

1.4 QRA Scope of Work

A quantitative risk analysis (QRA) of the proposed Project has been conducted. This QRA was conducted in response to the Project applicant's request for a public safety risk assessment, an environmental risk assessment for the oil transportation operations, as well as to support Project design optimization and risk mitigation.

The scope of work consisted of the following principal tasks applied to Phases 2 and 4:

Task 1: Project Information Assimilation

(a) General layout, topography, facility location, and site characteristics.

(b) Facility details including design and process description for each system and subsystem. Evaluation of contiguous isolatable segment volumes including the static and dynamic component of gas releases resulting from loss of containment.

(c) Operational information including contiguous segment isolation times.

(d) Public exposure within estimated hazard zone and proportion of that time spent indoors and outdoors at various locations.

(e) Meteorological data including stability class annual distribution and associated wind directions and intensities.

Task 2: Hazard Scenario Definition

(a) Subdivision of facilities into systems and subsystems associated with different loss of containment scenarios.

(b) Evaluation of potential release volumes for each scenario.

(c) Definition of hazardous fluid compositions.

Task 3: Frequency Analysis

(a) Choice of appropriate loss of containment (LOC) unit failure frequencies from failure frequency databases.

(b) Evaluation of appropriate LOC frequencies to characterize each segment hazard scenario.

(c) Fault tree analysis of generic well blowout frequencies to provide appropriate values for the proposed well operations.

Task 4: Consequence Analysis

(a) Definition of principal hazardous consequences including pool fires, flash fires, and explosions. Review of hydrogen sulfide toxicity potential.

(b) Evaluation of consequence evolution utilizing event trees.

(c) Categorization of representative consequence scenarios based on gas volume releases.

(d) Modeling of each representative release scenario (including flash fires and explosions), and definition of distances to significant damage levels.

Task 5: Public Risk Assessment

(a) Integration of probabilities of initial release, consequence evolution, lethality, transport mechanisms, and public exposure to generate measures of individual and collective risk.

(b) Presentation of individual and collective risk measures.

(c) Assessment of public risk acceptability.

Task 6: Environmental Risk Assessment

(a) Definition of environmental hazards from truck and oil pipeline product transportation.

(b) Conduct of environmental QRA based on spill probability and volume.

(c) Assessment of environmental risk acceptability.

Task 7: Risk Mitigation

(a) Description of generic risk mitigation measures applicable to mitigate loss of containment offsite risks.

(b) Discussion of optimal set of risk mitigation measures based on due diligence.

Task 8: Reporting

A Preliminary Summary Report [9] and this Final Report were completed at the conclusion of the work.

Figure 1.4 shows the functional workflow associating the principal tasks.

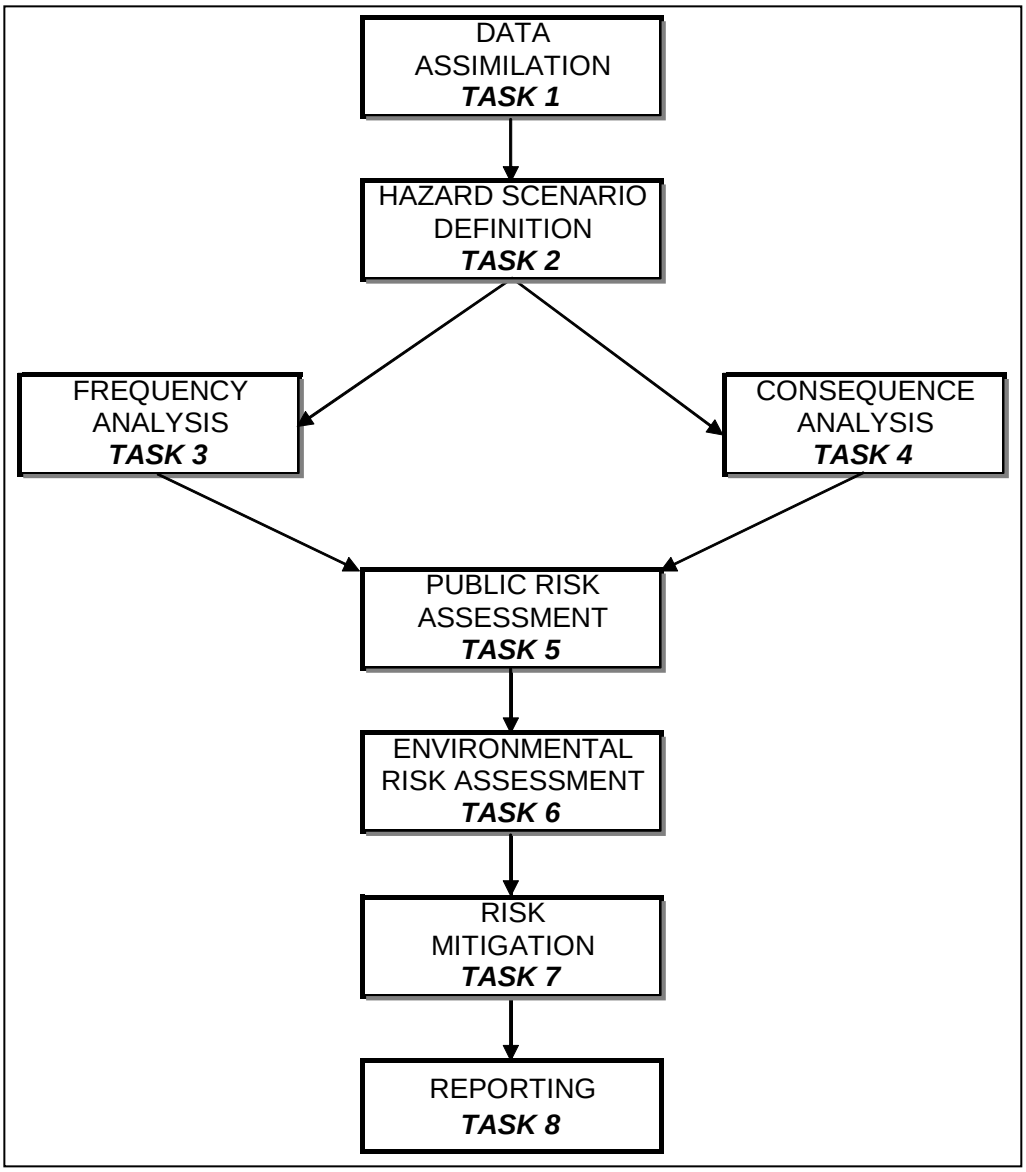


Figure 1.4
Work Flowchart

1.5 Use of Exponential Notation

Most of the quantities associated with risk analysis are very small, with values in the fractions of millions. Exponential notations, such as 1.57E-06, is used extensively throughout the numerical reporting in this QRA. The above value, in scientific, decimal, percentage, and per million forms can also be given as follows:

$$
\begin{aligned}
1.57\text{E-}06 &= 1.57 \times 10^{-6} \\
&= 0.00000157 \\
&= 0.000157\% \\
&= 1.57 \text{ per million}
\end{aligned}
$$

There are numerous advantages to using exponential notation in the form of 1.57E-06, as follows:

- It is compact, requiring the same number of spaces regardless of its value.
- It is the usual output of Microsoft Excel printouts, so these tabular or graphical printouts do not need to have their values converted to other notations.
- It avoids confusion from possible miscounting of zeros.
- Risk values are generally very small, so they can be most conveniently expressed as exponentials.
- Small risk values are easily comparable (for example, 1.0E-08 is clearly three orders of magnitude smaller than 1.0E-05).

1.6 Outline of Report

Following this introduction, sequential chapters of this final report deal with each of the main steps of the risk analysis process as follows:

- Chapter 2 – Project Information
- Chapter 3 – Hazard Scenarios
- Chapter 4 – Frequency Analysis
- Chapter 5 – Consequence Analysis
- Chapter 6 – Risk Assessment
- Chapter 7 – Environmental Risk
- Chapter 8 – Risk Mitigation
- Chapter 9 - Conclusions

CHAPTER 2

PROJECT INFORMATION

2.1 Project Information Requirements for Integrated Risk Assessment

The following general categories of information on the Project and its setting are required to conduct the QRA:

- Site characteristics
- Proposed facility information
- Public population distributions
- Meteorological data

2.2 Site Characteristics

The authors conducted a site visit in September 2012, including a visual inspection of the site and its vicinity. Pacific Development Solutions [31] provided detailed mapping and population data for the Project. Figure 2.1 shows an aerial photograph of the site, while Figure 2.2 shows the proposed gas pipeline route. Both figures provide estimates of permanent resident and worker populations [31] discussed later in Section 2.4.

Figure 2.1 provides the location of the Project site in its local setting and shows the existing conditions on and in the vicinity of the Project site. As indicated in Figure 2.1, the Project site is bounded by the following: to the east by Valley Drive, the Veterans Parkway (Hermosa Valley Greenbelt/Trail), Ardmore Park and, further to the east, by Ardmore Avenue and residential development; to the south by 6th Street, the City Beach Self Storage facility, light manufacturing land uses and, further to the south, South Park and residential development; to the west by light manufacturing land uses, Cypress Street and, further to the west, residential development; and to the north by light manufacturing land uses and, further to the north, residential development and 8th Street.

The Project site is currently developed as the City Maintenance Yard and the proposed Project would require the relocation of this facility to another site or sites as determined by the City. As indicated in Figure 2.1, existing development on the Project site consists of three buildings, two trailers, storage containers, sheds, trash bins, a propane tank, concrete paving and asphalt, fencing, and masonry walls. In addition, within the boundaries of the Project site, there is an asphalt parking area to the south of the City Maintenance Yard that provides 15 parking spaces for employees (between the hours of 6:00 a.m. and 6:00 p.m.) and for the public after hours (6:00 p.m. to 6:00 a.m.) and on weekends and holidays.

The Project site is relatively flat, sloping slightly from east to west in consonance with the prevailing gradient in the area. To the east, directly from Valley Drive, the Hermosa Valley Greenbelt/Trail is located in a depression that follows the former railroad right-of-way where it is located. From Ardmore Park and Ardmore Avenue, there is a gradual ascent of the terrain to the Pacific Highway further to the east. To the west, the gradient is downwards, to Loma Drive, and then gradually rises westwards to a ridge followed by a continuous slope down to the seashore. For the purposes of the present investigation, the north-south gradient across the Project site and its neighborhood may be considered negligible.

Figure 2.2 provides the conceptual alignment of the proposed offsite underground gas pipeline and the conceptual location of the proposed metering station. An offsite underground pipeline for the transport of gas would be constructed for a distance of 0.43 mile in the right-of-way (ROW) of southbound Valley Drive (which is one-way starting at 2nd Street) in the City of Hermosa Beach to a tie in to a Southern California Gas Company (SCG) gas line in the SCE Utility Corridor east of N. Francisca Avenue in the City of Redondo Beach.

The gas pipeline would consist of two parallel pipelines, four inches in diameter, and located at a depth of approximately 3.5 to 4 feet below ground surface (bgs) within the road ROW until it ties into the SCG line at a proposed metering station immediately to the east of N. Francisca Avenue. The pipeline would be a loop system that allows for the gas to be returned to the Project site for further treatment in the event that the produced gas did not meet SCG specifications. The metering station site, which would be provided as a part of the proposed Project and owned by SCG, would be approximately 40 by 60 feet in size and surrounded by an 8-foot high block wall.

As shown in Figure 2.2, the gas pipeline is bounded: to the east by the Veterans Parkway and Ardmore Park and, further to the east, by Ardmore Avenue and residential development in the City of Hermosa Beach; and to the west by the City Beach Self Storage facility, light manufacturing land uses, South Park, and residential development in the City of Hermosa Beach and a self storage facility and facilities associated with the AES Power Plant to the west in the City of Redondo Beach.

Figures 2.3 to 2.14 show characteristics of the immediate vicinity of the site, the existing site itself, and the gas pipeline route by means of reproductions of photographs taken by the author during a September 2012 site visit.

Figure 2.1
Facility Site

Figure 2.2: Gas Pipeline Route

Figure 2.3
Corner of Cypress Street and 6th Street

Figure 2.4
View North along Cypress Street

Figure 2.5
Building Adjacent to the SW Corner of the Site

Figure 2.6
View South on Cypress Street

Figure 2.7
Building Adjacent to North Side of the Site

Figure 2.8
Building Adjacent to the NE Corner of the Site

Figure 2.9
Existing Site Operations

Figure 2.10
Propane Tank on Existing Site

Figure 2.11
Site Exit to Valley Drive

Figure 2.12
View South from Site Exit along Valley Drive

Figure 2.13
View South along Pipeline Route on Valley Drive

Figure 2.14
Typical Residential Condos along Pipeline Route

2.3 Facility Information

Information on the proposed facilities for Phases 2 and 4 was provided by E&B Natural Resources [19, 20], Processes Unlimited [32], and InterAct [24].

2.3.1 Phase 2: Drilling and Testing

The purpose of Phase 2 is to conduct the drilling and testing of wells in order to determine the potential productivity and economic viability of the proposed Project. During this phase, three test wells and one water disposal/injection well will be drilled. These wells would be drilled utilizing directional drilling technology, which enables the wells to be drilled laterally for long distances, so that the bottom-hole locations may be located several thousand feet from the surface location of each well head on the Project site.

Before the drilling of any wells, a concrete well cellar will be constructed to provide containment during the drilling period. After the well cellar is completed, an electric drilling rig, with a derrick of approximately 87 feet in height, will be brought to the Project site, and temporary oil production equipment will be installed. This would include, but will not be limited to, drilling equipment, a gas combustor (enclosed ground flare), mud tanks, liquid storage tanks, piping, pipe racks, pumps, and vessels [32]. In addition, a temporary construction trailer and support vehicles would be provided. The equipment and the trailers would be delivered by truck to the Project site.

Once the drilling equipment set up is complete, the drilling rig would operate continuously for 24 hours per day, seven days per week, until the appropriate depths and bottom-hole locations have been reached. It is estimated that this would take approximately 30 days per well for each of the four wells [20]. The temporary oil production equipment and facilities on the Project site would be used to process the oil, by the removal of water and solids, to a standard that would be suitable for sales. Noise abatement will be incorporated into the design of the drilling rig and temporary oil production equipment and facilities.

The production equipment would be screened from view by 32-foot sound attenuation walls and landscaping. All waste generated by the test drilling would be transported by truck to appropriate disposal sites.

Each well would produce liquid pumped to the surface that would be an emulsion of oil, natural gas, and water. The liquid would be processed to produce a final crude oil product suitable for sales. During this phase, the facility is designed to process up to 800 barrels of oil and 250,000 standard cubic feet of gas per day. After the oil processing, the oil would be removed from the Project site by truck and delivered to an off-site receiving location at 2650 Lomita Boulevard in Torrance. The gas produced during Phase 2 would be disposed of onsite through the use of a gas combustor (enclosed ground flare). All produced water from the wells on the Project site would be processed onsite and injected into the ground using the water disposal/injection well.

A comprehensive fire protection system as required by Federal, State, and local codes, ordinances and regulations would be provided for in Phase 2.

2.3.2 Phase 4: Development and Operations

The purpose of Phase 4 is to maximize oil and gas recovery from the reservoir by drilling additional wells and activating the permanent facility. To accomplish this, Phase 4 would result in: the drilling of the remaining wells for a total of 30 oil and gas wells and 4 water disposal/injection wells: the start up of the operation of the permanent oil production equipment; and the transport of the crude oil and natural gas by pipeline (constructed in Phase 3) to their appropriate destinations [20]. During this phase, the facility is designed to process 8,000 barrels (bbl) of oil and 2.5 million standard cubic feet (SCF) of natural gas per day. [20].

The drilling of the remaining wells would involve the same activities as described above for Phase 2. Once the remaining wells were drilled, the drilling rig would be removed from the Project site.

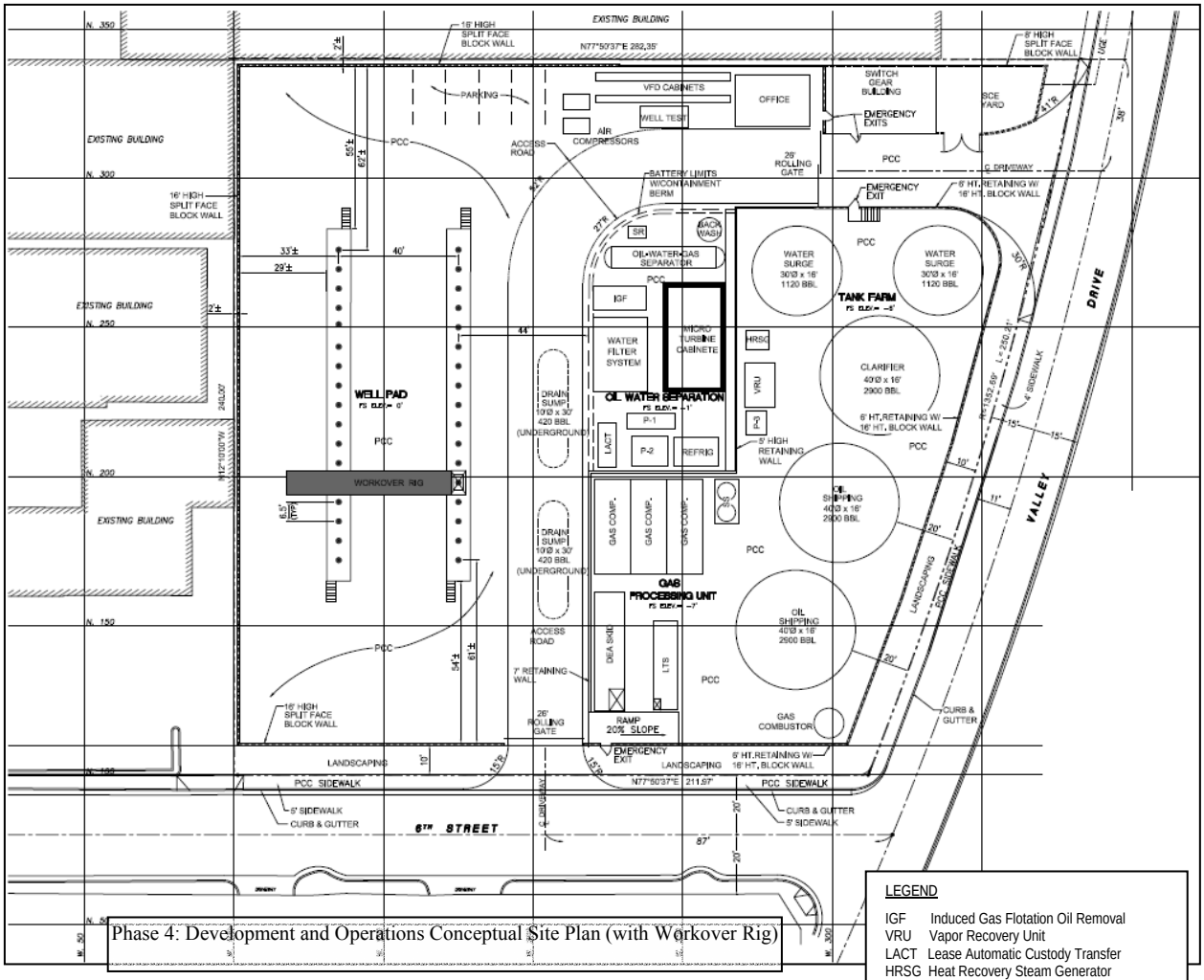
During the ongoing operation of the proposed Project, the active wells would require periodic routine service. These activities could include the replacement of down-hole pumps, piping, and cleaning. These maintenance or workover activities would typically be accomplished by utilizing a service rig or workover rig [20]. In addition, there would be an occasional need for other services such as facilities maintenance and solid and liquid waste removal. Regular inspection, monitoring, and maintenance would be performed to ensure the integrity of all operating equipment. The offsite pipelines would be internally inspected to ensure their continued integrity.

The ongoing maintenance and operation of the proposed Project would occur in compliance with all applicable federal, state, and local laws, regulations, ordinances, and permit conditions. In addition, the design and operation of the Project would reflect the most current oil and gas technology and safety systems and incorporate additional standards that exceed current regulatory requirements [20, 24]. The Applicant would employ experienced oil field operators, and monitor activities on a 24-hour basis in order to assure the safety and security of the ongoing operation and integrity of the proposed Project. Figure 2.15 illustrates the Phase 4 general layout. A heater treater was assumed in place of microturbines to provide a worst case scenario.

2.3.3 Existing Facilities

Figure 2.16 shows the site as currently used by the City of Hermosa Beach as a maintenance facility. The operations include a variety of activities such as repair and maintenance of vehicles, storage of materials, supplies, and equipment; a workplace for city workers who repair and maintain facilities and equipment in the city; and for storage and painting of signs. The following materials and activities are associated with potential hazards, as discussed in the 1998 QRA [10] by the author:

- 50 vehicle round trips per day
- 500 gallon above-grade storage tank for propane with a maximum operating pressure of 200 psi
- Propane, gasoline, and diesel surface vehicle loading pumps
- Acetone
- Paint Thinner
- Various other solvents and paints



Phase 4: Development and Operations Conceptual Site Plan (with Workover Rig)

Figure 2.15
Phase 4 General Layout

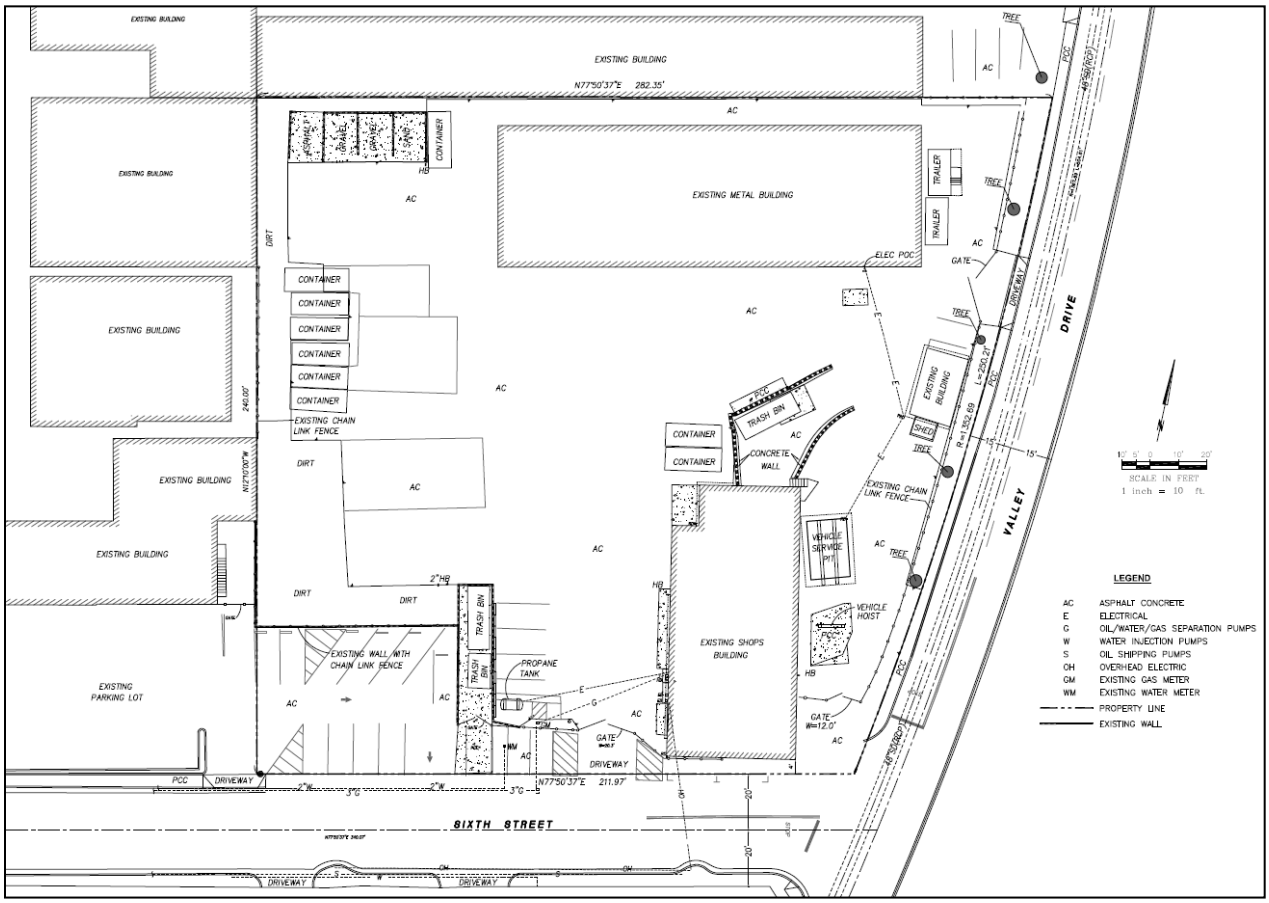


Figure 2.16
Existing Facilities Layout

2.4 Population Data

The permanent population distributions provided by Pacific Development Solutions [31], as shown by the red numbers in Figures 2.1 and 2.2. The transient population distributions, such as the public greenbelt/trail users, were estimated from observations. Figure 2.1 (on page 2.3) shows the population distribution in the vicinity of the Project site. As may be seen, the site is surrounded on all four sides by areas utilized by the public for light manufacturing, residential, or recreational purposes. Immediately to the east, across Valley Drive is the public greenbelt/trail which is routinely used by joggers and walkers. To the east of that is Ardmore Park. Further east, across Ardmore Avenue, is a medium density residential area, in which residential units have been characterized by an average occupancy of two persons. To the west, across the fence along the property line is a parking area with an adjacent small business area made up of light manufacturing uses. Similar businesses consisting of light manufacturing uses appear on the west side of Cypress Street, and to the north. To the south, across 6th Street, are a number of medium sized enterprises, with occupancy in the order of five permanent workers per unit. Figure 2.2 gives the population distribution along the gas pipeline route which runs south down Valley Drive, showing a range of unit-occupants from 2 to 190.

Table 2.1 summarizes parameters describing the amount of time spent at the location and the percentage of that time that people are outdoors and therefore more vulnerable to possible hazards from the proposed Project. Specifically, Table 2.1 gives the type of population as residential, outdoor worker, and indoor worker. The table gives the amount of time spent at the location and outside as a proportion of the total possible time. The right hand column gives the Individual Specific Risk Factor (ISRF). The ISRF is the factor by which a hypothetical 100% outdoor exposure is multiplied to provide the effect of exposure, considering the time spent at the specified location and the proportion of that time on location spent indoors, with a specified level of protection due to the indoor shelter. In the case of the potential principal hazard, which is a flash fire, (a relatively transient natural gas conflagration), any of the buildings observed around the site or pipeline route are likely to provide close to 100% protection. Therefore, a protection factor of 0.9 or 90% was conservatively used.

In addition to exposure of the permanent population described in Table 2.1, exposure of transients (eg. joggers, walkers, homeless) was estimated and used later in evaluating the collective risks.

Table 2.1
Population Distribution around Proposed Site

CATEGORY	On Site								Exposure hours / week		Shelter Factor	Shelter Protection Effect	ISRF
	Inside				Outside								
	Weekday		Weekend		Weekday		Weekend						
	days /week	hours /day	days /week	hours /day	days /week	hours /day	days /week	hours /day	Inside	Outside			
Resident	5	10	2	12	5	1	2	5	74	15	0.1	0.9	0.133
Indoor worker	4	7	1	7	4	1	1	1	35	5	0.1	0.9	0.051
Outdoor worker	1	1	0	0	1	5	0	0	1	5	0.1	0.9	0.030

2.5 Meteorological Data

Meteorological data required for the conduct of the QRA includes atmospheric conditions, and wind intensities and directions.

Atmospheric stability class data was based on the LAX [5, 14, 15, 16, 37], EIS, resulting in the following simplified stability class distribution:

- Unstable (A, B, C): 20%
- Neutral (D): 60%
- Stable (E, F): 20%

Data on wind characteristics was obtained from data for the nearest weather station located at LAX [5, 14]. The data give the distribution of wind directions for 16 compass directions, for each of 7 stability classes as well as summaries for the representative unstable (A, B, C) and stable (E, F, G) atmospheric stability classes. Wind intensities are also given for intensity

intervals of 1 metre/second (m/s), from 0 to 6 m/s. Analysis of these data for representative conditions giving relevant wind directions in four compass directions, is shown in Table 2.2. The reader is reminded that wind direction means the direction from which the wind is blowing. Hence, downwind effects such as flash fires tend to occur more in a direction opposite to that given for the wind.

Table 2.2
Site Wind Characteristics

Wind Direction	December, January, February		March, April, May		June, July, August		September, October, November		Year Average	Average (with calm distribution)
	%	%	%	%	%	%	%	%	%	%
N	5	16.5	2	7.5	1	4.0	3	9.0	9.3	9.9
NNE	4		2		1		2			
NE	6		2		1		2			
ENE	8		4		1		5			
E	15	35.5	10	21.0	4	11.5	10	22.5	22.6	24.2
ESE	8		5		4		5			
SE	3		2		4		3			
SSE	2		2		3		3			
S	2	9.0	2	10.5	2	12.0	2	11.5	10.8	11.5
SSW	2		2		1		2			
SW	3		7		8		6			
WSW	13		27		35		23			
W	13	31.0	23	56.0	27	67.5	20	49.0	50.9	54.4
WNW	2		2		1		2			
NW	3		1		1		2			
NNW	3		2		1		2			
CALM	8	8.0	5	5.0	5	5.0	8	8.0	6.5	0.0
Total	100	100	100	100	100	100	100	100	100	100

CHAPTER 3

HAZARD SCENARIOS

3.1 Introduction on Hazard Scenario Definition

Hazard is the potential for harm or adverse effect. A hazard scenario is the way in which the adverse effect can be realized. The first technical step in risk analysis is the identification or definition of hazard scenarios. What can go wrong? Typical hazard scenarios include the release of a flammable hydrocarbon due to the rupture of a pipeline, or a natural gas release due to a leak in a compressor pipe. Many hazard scenarios can be characterized by the properties of the damaging incident and associated consequences. The characterization of hazard scenarios is a semi-quantitative step involving the qualitative description of the hazard scenario and a quantitative characterization of its most important parameters such as type of fluid released and its release rate and volume.

In summary, hazard scenario definition, as approached in this QRA, consists of three principal steps as follows:

- Definition of each contiguous isolatable segment capable of releasing natural gas from a loss of containment (LOC).
- Identification of each segment release scenario and its location within each facility (Phase).
- Evaluation of potential natural gas release volumes for each release scenario.
- Grouping of release scenarios by release volumes for input to consequence analysis.

Because the objective of the work is to assess public and environmental offsite risks, only hazard scenarios which have a potential facility offsite and pipeline offsite acute risk potential have been selected. Specifically, the proposed facility produces an emulsion of oil and gas and processes it to a sales gas and sales oil product. From a review of the facility configuration [19, 32], it has been determined that oil spills from facility equipment would remain within the confines of the site and therefore pose no acute offsite risks. However, gas releases either from the process fluids or following gas processing have the potential to create offsite hazards in the form of natural gas vapors with flammable concentrations. Accordingly, the principal hazard scenarios considered are those associated with natural gas releases.

Because of the design and operation of the facility, gas releases from failures or losses of containment of contiguous isolatable segments can be quantified as the release of gas, which would continue to flow once a loss of containment or rupture of a segment occurs, and the amount of gas released after the segment is shut-in. The amount of gas or fluid flowing through a release orifice prior to segment shut-in is termed the **dynamic volume** and the amount of fluid released after the segment is shut-in is termed the **static volume**.

The amount of gas released depends on the operating conditions of the failed segment, including pressure, temperature, volume, and flow rate, as well as on the size of the loss of containment orifice. Basically, two representative orifice sizes have been considered;

namely, holes and ruptures. Holes are defined as release orifices with approximately 10% of the flow area, while ruptures are considered to be release orifices with an area equivalent to the flow area. In the case of a container, such as a pressure vessel, the hole release will generally occur over a measurable duration, while a rupture release is considered to be instantaneous [27].

3.2 Hazard Scenario Nomenclature

Nomenclature of the hazard scenarios is based on a series of acronyms to facilitate convenient and precise reference to these scenarios.

Because numerous hazard scenarios were analyzed, each having a relatively lengthy generic description, a code has been developed to characterize each hazard scenario uniquely. The code is best explained through illustration for a typical hazard scenario such as **HB-P2-S01-H-MN** where:

- The first two letters, HB, identify this Project as Hermosa Beach
- The next characters, in this case P2, identify the phase of the Project as Phase 2.
- The next characters, S01, specify the scenario – in this case Scenario 1. In the case of lines (pipe), the scenario prefix is L.
- The next letter, in this case H, characterizes the size of the release orifice as a Hole. Alternatively, R stands for rupture.
- The final letters, which do not begin to appear in the scenario dimensions until the consequence analysis part of the risk analysis process begins (Chapter 4), characterize the meteorological stability conditions of the release. In this case MN signifies Neutral. The other two principal conditions are MU for Unstable and MS for Stable.

3.3 Natural Gas Composition

The typical gas composition for the process gas in the Project, provided by [32], is shown in Table 3.1.

Table 3.1
Produced Gas Composition

Component	Value Mole % or ppm
Water	7.06%
Carbon Dioxide (estimate)	4.50%
Methane	86.34%
Ethane	1.86%
Propane	0.08%
i-Butane	0.05%
n-Butane	0.03%
i-Pentane	0.02%
n-Pentane	0.00%
Hexane+	0.06%
Hydrogen Sulfide	6.00 ppm

3.4 Phase 2 Release Scenarios

For the drilling and test phase, Phase 2, the release scenarios are subdivided into process segments and the interconnecting pipes, based on the information provided [32]. Table 3.2 summarizes the subdivision of the Phase 2 operation into the isolatable segments. The table provides the entire potential release volume in standard cubic feet, as well as the pressure and temperature. In the case of Segment 1, where potential releases would be dominated by blowouts potentially occurring during the drilling phase. In the instance of a blowout a continuous release of fluids would occur, with a resultant initial maximum gas release of approximately 6 pounds of natural gas per minute rapidly depleting to zero. As will be noted in Sections 5.6 and 6.4, such a release rate would have no acute onsite or offsite damaging consequences. Because the total volume of the piping is relatively small, totaling 461 standard cubic feet as shown in Table 3.3, in the subsequent analysis, the piping has been considered as two segments, one high and one low pressure. This approximation is conservative, but considering the relatively small total volume, is inconsequential.

Table 3.2
Phase 2 Segments

MODULES	SEGMENT	SEGMENT DESCRIPTION			Volume SCF	Pressure PSIG	Temp. °F
WELLS	1	WELL DRILLING			n/a	n/a	n/a
OIL/WATER SEPARATION	4	FREE WATER KNOCKOUT			895.0	0.1	100
	7	INDUCED GAS FLOTATION UNIT			156.0	0.1	100
	8	INJECTION WATER FILTER			166.7	0.1	100
	13	WATER SURGE TANK			960.0	0.1	100
TANK FARM	9	DRAIN VESSEL			896.0	0.1	100
	11	SHIPPING TANK (7)			6,271.0	0.1	100
COMPRESSION EQUIPMENT	17	VRU SUCTION DRUM			17.0	0.1	99
	18	VRU DISCHARGE SCRUBBER			51.0	48.9	120
GAS COMBUSTER SYSTEM	19	KNOCKOUT DRUM			51.0	0.1	100
LINE 1	L1	Module 1: Wells to Test	to	Module 2, Test Station	44.5	65.0	100
LINE 2	L2	Module 2: Test Station	to	Module 3, Junction, Prodn Header	7	65.0	100
LINE 3	L3	Module 1: Wells, Production	to	Module 3, Junction, Prodn Header	158.5	65.0	100
LINE 4	L4	Module 3, Junction, Prodn Header	to	Module 4: FWKO	16.7	14.8	100
LINE 5	L5	Module 4: FWKO Gas Outlet	to	Module 5, Junct with IGF Gas	11.8	14.8	99
LINE 6	L6	Modules 7 & 8, IGF Gas	to	Module 5, Junct with FWKO Gas	3.0	14.8	100
LINE 7	L7	Module 5, Junct, IGF and FWKO Gas	to	Module 6, junct with VRU Suct hdr	12.1	14.8	99
LINE 8	L8	Module 9, Drain Sump	to	Module 10, Junct Drain Tk Gas w/Hdr	0.2	14.8	
LINE 9	L9	Module 11, Shipping Tanks	to	Module 12, Junct Ship Tk Gas w/ Hdr	7.1	14.8	99
LINE 10	L10	Module 13, Water Surge Tank	to	Module 14, Junct w/VRU Suct Hdr	8.8	14.8	
LINE 11	L11	Module 15, Truck Loading Rack	to	Module 16, Loading Rack Gas w/Hdr	5.8	14.8	98
LINE 12	L12	Multiple Junctions	to	Module 17, VRU Suction Drum	26.3	14.8	100
LINE 13	L13	Module 17, VRU Suction Drum	to	Module 18, VRU Disch Drum	37.0	63.6	120
LINE 14	L14	Module 18, VRU Disch Drum	to	Module 19, Combustor KO Drim	100.2	63.6	120
LINE 15	L15	Module 19, Combustor KO Drim	to	Module 20, Gas Combustor	34.2	14.8	100

Table 3.3
Phase 2 Piping Summary

Category	Length (ft)	SCF
4 in and smaller	1,012	261
6 in and larger	245	199
Total	1,257	461

3.5 Phase 4 Release Scenarios

The contiguous isolatable segments providing a basis for release scenarios for Phase 4, are presented in Table 3.4 [32]. As can be seen, some of the segments include the interconnecting piping, unlike Phase 2, where interconnecting piping was considered to comprise individual isolatable segments. Table 3.4 provides both the static and dynamic volumes in standard cubic feet (SCF), as well as the total volumes per segment.

There are basically 30 onsite segments in Phase 4, and the pipeline from the property comprises number 31, which is treated separately because it is a pipeline with linear rather than concentrated characteristics. Wells are not shown, as they are treated separately in Sections 4.2.2, 5.6, and 6.4.

Table 3.4
Phase 4 Release Segments

MODULE	SEGMENT NUMBER	SEGMENT DESCRIPTION	FREQUENCY CATEGORY	STATIC VOLUME, ACF	PRESSURE, PSIA	TEMPER-ATURE, °F	STATIC VOLUME, SCF	DYNAMIC VOLUME, SCF	TOTALSCF PER SEGMENT	TOTAL SCF PER SEGMENT
VRU Compressor Inlet Piping	1	PIPING, 4-INCH AND SMALLER	PIPING	9.6	14.8	120	8.7	29.3	38.0	44.1
		GLYCOL KO DRUM, V-923	VESSEL	6.7	14.8	120	6.0		6.0	
Equipment Venting to VRU Compressor	2	DRAIN VESSEL, V-104B	VESSEL	389.9	14.8	111	357.6		357.6	357.6
	3	DRAIN VESSEL, V-104A	A TANK	389.9	14.8	111	357.6		357.6	357.6
	4	SHIPPING TANK, 140A	A TANK	4,466.1	14.8	120	4,032.2		4,032.2	4,032.2
	5	SHIPPING TANK, 140B	VESSEL	4,466.1	14.8	120	4,032.2		4,032.2	4,032.2
	6	INDUCED GAS FLOTATION, V-102	VESSEL	142.1	15.2	100	136.5		136.5	136.5
	7	INJECTION WATER FILTER, V-103	VESSEL	140.3	19.7	100	174.6		174.6	174.6
	8	CLARIFIER, T-141	VESSEL	4,466.1	14.8	100	4,176.3		4,176.3	4,176.3
	9	WATER SURGE TANK, T-143	A TANK	2,414.0	14.8	100	2,257.3		2,257.3	2,257.3
	10	WATER SURGE TANK, T-142	A TANK	2,414.0	14.8	100	2,257.3		2,257.3	2,257.3
	11	HEATER TREATER	VESSEL	718.4	15.2	130	654.8		654.8	654.8
VRU Suction Design	12	VRU SUCTION DRUM, V-450	VESSEL	17.9	14.8	99	16.8		16.8	16.8
VRU Internal Piping	13	PIPING, 4-INCH AND SMALLER	PIPING	5.8	45	100	16.5	10.1	26.6	987.8
		VRU DISCH DRUM, V-453	VESSEL	13.2	45	120	36.2		36.2	
Piping to Main Compressor Plus Flare		PIPING, 4-INCH AND SMALLER	PIPING	2.0	45	120	5.6	7.7	13.3	
		PIPING, 6-INCH AND LARGER	PIPING	83.3	45	120	123.4	788.3	911.7	
V-101	14	FREE WATER KNOCKOUT, V-101	VESSEL	718.4	45	130	1,938.6		1,938.6	1,938.6
V-921	15	AMINE FLASH TANK, V-921	P TANK	9.0	45	156	23.3		23.3	23.3
V-932	16	3-PHASE SEPARATOR, V-932	VESSEL	16.3	457	70	498.2		498.2	498.2
V-901A	17	COMPR SUCTION DR, V-901A	COMPRESSOR	7.3	45	120	20.0		20.0	20.0
V-901B	18	COMPR SUCTION DR, V-901B	COMPRESSOR	7.3	45	120	20.0		20.0	20.0
Int Piping "A"	19	PIPING, 4-INCH AND SMALLER	PIPING	19.0	165	120	191.0	101	292.0	1,085.1
Int Piping "B"		PIPING, 4-INCH AND SMALLER	PIPING	19.0	165	120	191.0	101	292.0	
V-902A		1ST STG DISCHG DRUM, V-902A	COMPRESSOR	7.3	165	120	73.8		73.8	
V-902A		1ST STG DISCHG DRUM, V-902B	COMPRESSOR	7.3	165	120	73.8		73.8	
COMPR TO M22		PIPING, 4-INCH AND SMALLER	PIPING	6.5	165	120	65.0	288.5	353.5	

Table 3.4: Phase 4 Release Segments ~ Continued ~

MODULE	SEGMENT NUMBER	SEGMENT DESCRIPTION	FREQUENCY CATEGORY	STATIC VOLUME, ACF	PRESSURE, PSIA	TEMPER-ATURE, °F	STATIC VOLUME, SCF	DYNAMIC VOLUME, SCF	TOTALSCF PER SEGMENT	TOTAL SCF PER SEGMENT
SULFA SCRUB	20	SULFASCRUB VESSEL, V-923A	VESSEL	180.5	165	120	1,816.8		1,816.8	1,816.8
M23 TO M24	21	PIPING, 4-INCH AND SMALLER	PIPING	1.8	165	120	17.8	144.3	162.1	162.1
SULFA SCRUB	22	SULFASCRUB VESSEL, V-923B	VESSEL	180.5	14.8	120	163.0	0	163.0	163.0
ABSORBER TO 2ND STG SUCTION	23	AMINE ABSORBER	VESSEL	101.1	165	156	958.1		958.1	1,295.4
		PIPING, 4-INCH AND SMALLER	PIPING	5.8	165	156	55.3	282	337.3	
Residue Gas to Inject	24	PIPING, 4-INCH AND SMALLER	piping	3.7	20	100	4.7	6.8	11.5	11.5
2ND STG SUCT DRUM, V-903A	25	2ND STG SUCT DRUM, V-903A	VESSEL	7.3	165	130	72.2		72.2	72.2
2ND STG SUCT DRUM, V-903B	26	2ND STG SUCT DRUM, V-903B	VESSEL	7.3	165	130	72.2		72.2	72.2
2nd Stg Int Piping, "A"	27	PIPING, 4-INCH AND SMALLER	PIPING	19.0	477.8	120	553.1	96.3	649.4	862.2
		2nd STG DISCH DRUM, V-904A	VESSEL	7.3	477.8	120	212.8		212.8	
2nd Stg Int Piping, "B"	28	PIPING, 4-INCH AND SMALLER	PIPING	19.0	477.8	120	553.1	96.3	649.4	862.2
		2nd STG DISCH DRUM, V-904A	VESSEL	7.3	477.8	120	212.8		212.8	
Gas Line to Lts	29	PIPING, 4-INCH AND SMALLER	PIPING	9.1	477.8	100	274.9	276.2	551.1	1,096.8
		COLD SEPARATOR	VESSEL	16.3	477.8	45	545.7		545.7	
PL to Property Line	30	PIPING, 4-INCH AND SMALLER	PIPING	20.3	477.8	100	613.8	137.6	751.4	751.4
PL from Property	31	PIPING, 4-INCH AND SMALLER	PIPING	233.4	477.8	100	7,045.3	275.3	7,320.6	7,320.6

CHAPTER 4

FREQUENCY ANALYSIS

4.1 General Description of Spill Occurrence Frequency Analysis

When and how often will the spill event happen? The next step, the frequency analysis, involves an estimation of the likelihood of occurrence of each of the different types of hazard scenarios identified. In frequency analysis, it is customary to characterize frequencies of occurrence either on an annual basis, or on an incident basis. An example of an annual frequency of occurrence is 1 major storage tank spill per 100 years or one pipeline spill per year per 10 million pipeline kilometers. An example of an event frequency of occurrence is that 95% containment failures are minor leaks. Frequencies from publicly available sources [3, 4, 7, 25, 26, 27, 28] were used here for the frequency analysis.

If the frequency for the type and conditions of the event being studied is not directly available from the published statistics, it can be evaluated utilizing analytical techniques such as fault tree analysis [4, 12]. In fault tree analysis, the frequency of occurrence of a specific event can be derived by considering the probabilistic relationships of more basic events that lead to its occurrence. For the current analysis, failure frequencies for facilities and components were directly available from appropriate statistics, and therefore were derived without the application of fault trees except for well blowout frequencies.

It should be noted that "failure" in the context of the present QRA means a loss of containment (LOC) translating into a hydrocarbon release, namely natural gas, to atmosphere, as all facility oil spills are contained onsite. Offsite trucking and oil pipeline spills are discussed in Chapter 7. Other failures, such as malfunctions without losses of containment or minor leaks are not relevant within the context of this QRA, as they lead primarily to operational disruptions, and therefore, are not considered. Failure frequencies to support this QRA were generated for all facility, well, and pipeline components. Generally, the failure frequencies developed should be considered conservative as they do not explicitly include consideration of all safety measures proposed by E&B [24], but rather are based on western contemporary facility data.

4.2 Loss of Containment Frequencies

4.2.1 Process Equipment and Piping

The most comprehensive and current public database for piping and facility loss of containment (LOC) or failure frequencies published by the Dutch VROM [27] was used for a majority of these facility component failure frequencies. These frequencies are based on western world, or developed country, including incident statistics collected up to the present. Table 4.1 summarizes the LOC or failure frequencies for the principal categories of components. As can be seen, these include pressurized and atmospheric tanks, pressurized vessels, compressor components, above-grade process piping of less than 6-inch and greater than or equal 6-inch diameter including fittings, and the natural

gas 4-inch diameter pipeline. Frequencies for holes and ruptures are provided. Generally, holes refer to loss of containment orifices of roughly 10% diameter of the largest associated pipe in the case of the vessel, and for the case of the pipes, 10% of the flow area itself. Ruptures, in the case of equipment, are instantaneous releases of the full contents of the vessel, together with the dynamic component of flow until isolation occurs.

For the case of pipelines, frequencies published by the California State Fire Marshal (CSFM) [13, 21], the Alberta Energy and Utilities Board (AEUB) [3], and the Pipelines and Hazardous Materials Safety Administration [33] for relevant pipelines were considered. The 2006 AEUB frequencies were used as they provide more detail than the similar PHMSA [33] statistics, and values more current than the latest (1997) CSFM [33] statistics.

Table 4.1
Equipment and Piping LOC Frequencies

SCENARIO	Unit	HOLE	RUPTURE
		10% Diameter	Full Instantaneous
Pressurized Tanks	PER YEAR	1.00E-05	5.00E-07
Atmospheric Tanks	PER YEAR	1.00E-04	5.00E-06
Pressurized Vessel	PER YEAR	1.00E-04	5.00E-06
Centrifugal Compressor	PER YEAR	2.50E-04	3.50E-05
Process Piping < NPS6	PER FT-YEAR	6.10E-07	9.14E-08
Process Piping >= NPS6	PER FT-YEAR	1.52E-07	3.05E-08
Gas Pipeline NPS4	PER MILE-YEAR	1.27E-04	4.17E-05

4.2.2 Wells

Numerous databases on oil and gas well blowouts are available, including the Energy Resources Conservation Board (ERCB) data [22], and the International Association of Oil and Gas Producers (OGP) [25] databases. Both of these databases, however, provide blowout frequency data for a large and diverse population of oil and gas wells, rather than only the types of wells that are under consideration here. In addition, it is anticipated that the oil and gas emulsion which would be produced is highly viscous, requiring downhole pumps in order to produce the reservoir fluids to surface, reducing the likelihood of any kicks from the reservoir. And finally, during the drilling phase, the blowout preventer (BOP) used is Class III BOP equipped with shear rams, of a significantly higher specification and capability [20] than what is commonly used in heavy oil onshore drilling operations. Accordingly, the data published on the basis of standard oil and gas drilling operations requires some adjustments to more accurately reflect the type of operation proposed for the present Project.

OGP [25] recommends a value of 4.95 per 10,000 wells drilled as a full blowout frequency. This is somewhat more conservative than that derived by Bercha [6], so is used here. However, based on Bercha's study of blowouts [6], a well drilling blowout fault tree consists of two primary branches, as shown in Figure 4.1. What this fault tree depicts, is that in order to have a well blowout, meaning an uncontrolled flow of well fluids to the atmosphere, two conditions need to occur; namely, (1) a kick or an exceedance of atmospheric pressure fluids at the wellhead needs to occur, and (2) a failure to control the kick also needs to occur. These two events are joined through what

is called an "and gate" [4], which indicates that both events have to co-occur so that the probabilities of their occurrences need to be multiplied together to give their joint occurrence probability. The loss of control can occur in one of two ways; namely (1) the wellhead control equipment, the blowout preventer, could fail, or (2) the flow of fluids could occur outside the casing so that it cannot be controlled by the blowout preventer.

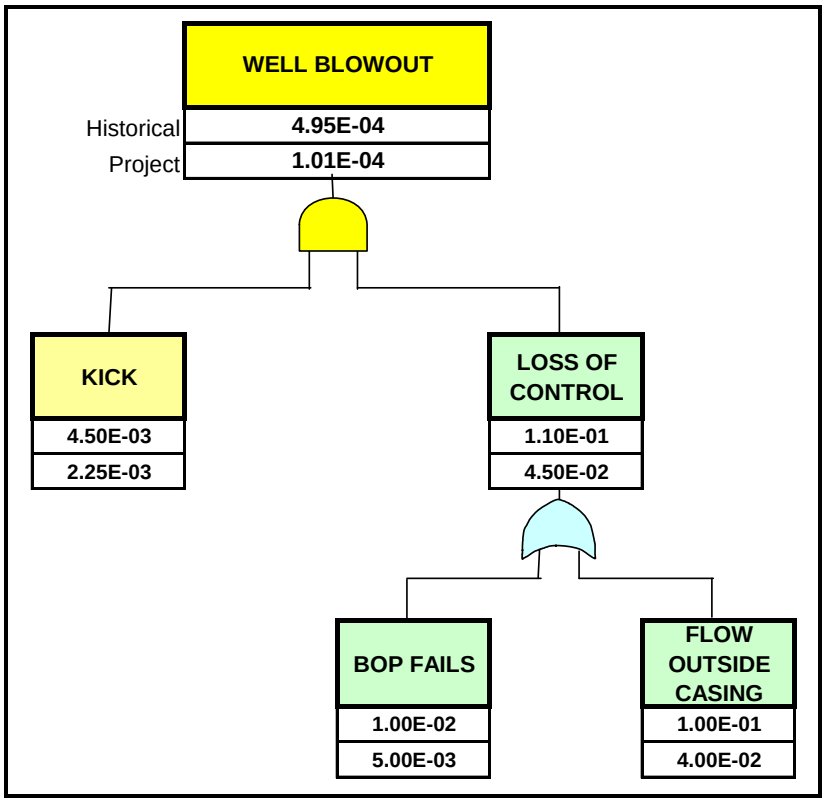


Figure 4.1
Well Blowout Fault Tree

Table 4.2 displays the likely appropriate adjustments based on the historical value for blowouts for each of the primary base events, considering the type of equipment, reservoir, and well fluids for the proposed Project. First of all, we consider the kick. Because the reservoir fluids are likely to be heavy, and downhole pumps are required to bring them to surface, it is unlikely that surface overpressure from kick situations would occur. A conservative reduction of 50% of the historical frequency has been used. The two events leading to loss of control – the failure of the BOP and flow outside of the casing – have been similarly adjusted. The BOP failure rate has been taken to be 50% of the historical value, while the probability that reservoir fluids would flow outside the casing has been reduced by 60%, leaving a value of 40% of the historical estimate. The resultant value of the drilling blowout frequency for the proposed Project is 1.0 per 10,000 wells drilled.

Table 4.2
Well Blowout Frequency per Well Drilled

Event	Historical Frequency	Project	
		% of Historical	Frequency
Well Blowout	4.95E-04	20	1.01E-04
Kick	4.50E-03	50	2.25E-03
Loss of Control	1.10E-01	41	4.50E-02
BOP Fails	1.00E-02	50	5.00E-03
Flow Outside Casing	1.00E-01	40	4.00E-02

Then, using a similar approach to the adjustment of historical producing well and workover blowouts from OGP [25], one can arrive at the unit blowout frequencies summarized in Table 4.3. Both the historical [25] and Project frequencies applicable here are given in this table.

For this project, a production well blowout annual probability is further reduced by a factor of 14/365 or 0.038, in addition to the 50% reduction resulting in a value of 1.9% of historical. Production wells, according to E&B [20], using data from the offset analogous project in Redondo Beach, could flow for a maximum of 14 days immediately after start of production, so that any workovers, which would only occur significantly later than 2 weeks after the start of production; work would not be subject to flow, so that a workover blowout could never occur.

Table 4.3
Blowout Frequency Summary

Events	Units	Historical	% Historical	Project
Drilling Blowout	per well drilled	4.95E-04	20	1.01E-04
Completion	per well completed	1.40E-04	50	7.00E-05
Producing Well Blowout	per well-year	3.90E-05	1.9	7.41E-07
Workover Blowout	per workover	2.60E-04	0	0.0

As will be seen in the next chapter, the consequence analysis, these blowout frequencies are somewhat academic, because of the very low anticipated absolute open flow (AOF) rates, which are not able to produce any offsite hazardous consequences.

4.3 Phase 2 Segment LOC Frequencies

The loss of containment (LOC) frequencies are obtained by combining the appropriate unit frequencies provided in Section 4.2 with the appropriate number of units or length of pipe. In the case of wells, as three wells would be drilled in the first year, a frequency of three times the individual well blowout value from Table 4.3 was utilized. Table 4.4 provides the facility segment LOC frequencies, while Table 4.5 provides these for the pipe segments.

Table 4.4
Phase 2 Segment LOC Frequencies

MODULES	Segment	Segment Number	SEGMENT DESCRIPTION	Release Frequency per Year	
				Hole	Rupture
WELLS	1	01	WELL DRILLING – 3 wells	n/a	3.03E-04
OIL/WATER SEPARATION	4	04	FREE WATER KNOCKOUT	1.00E-04	5.00E-06
	7	07	INDUCED GAS FLOTATION UNIT	1.00E-04	5.00E-06
	8	08	INJECTION WATER FILTER	1.00E-04	5.00E-06
	13	13	WATER SURGE TANK	1.00E-04	5.00E-06
TANK FARM	9	09	DRAIN VESSEL	1.00E-04	5.00E-06
	11	11	SHIPPING TANK (7)	7.00E-04	3.50E-05
COMPRESSION EQUIPMENT	17	17	VRU SUCTION DRUM	1.00E-04	5.00E-06
	18	18	VRU DISCHARGE SCRUBBER	1.00E-04	5.00E-06
GAS COMBUSTER SYSTEM	19	19	KNOCKOUT DRUM	1.00E-04	5.00E-06

Table 4.5
Phase 2 Piping LOC Frequencies

Line #	Segment	NPS	Length	Release Frequency per Year	
			ft	Hole	Rupture
1	L1	3	195	1.19E-04	1.75E-06
2	L2	3	15	9.14E-06	1.35E-07
3	L3	6	180	2.74E-05	2.15E-06
4	L4	6	35	5.33E-06	4.19E-07
5	L5	3	33	2.01E-05	2.96E-07
6	L6	3	16	9.75E-06	1.44E-07
7	L7	3	36	2.19E-05	3.23E-07
8	L8	2	10	6.10E-06	3.99E-08
9	L9	3	70	4.27E-05	6.28E-07
10	L10	3	150	9.14E-05	1.35E-06
11	L11	3	75	4.57E-05	6.73E-07
12	L12	4	140	8.53E-05	2.23E-06
13	L13	3	22	1.34E-05	1.97E-07
14	L14	4	250	1.52E-04	3.99E-06
15	L15	8	30	4.57E-06	6.38E-07

4.4 Phase 4 Segment LOC Frequencies

More detailed description of the segment frequency evaluation is provided for the segment release frequencies for Phase 4. Table 4.6 provides these frequencies, and shows the appropriate combinations of unit and length quantities to arrive at the segment hole and rupture frequencies.

The well blowout frequencies for well drilling, producing wells, and well workovers were dealt with separately for Phase 4, and are reported in Section 4.5.

Table 4.6
Phase 4 Segment LOC Frequencies

Segment #	Segment Description	VESSEL			PRESS. TANK			COMPRESSOR			PROCESS PIPING < NPS6			PROCESS PIPING >= NPS6			Release Frequency per year for Segment	
		#	Release Frequency per year		#	Release Frequency per year		#	Release Frequency per year		Length (ft)	Release Frequency per year		Length (ft)	Release Frequency per year			
			Hole	Rupture		Hole	Rupture		Hole	Rupture		Hole	Rupture		Hole	Rupture	Hole	Rupture
1	PIPING, 4-INCH AND SMALLER GLYCOL KO DRUM, V-923	1	1.00E-04	5.00E-06							414	2.52E-04	3.79E-05				3.52E-04	4.29E-05
2	DRAIN VESSEL, V-104B	1	1.00E-04	5.00E-06													1.00E-04	5.00E-06
3	DRAIN VESSEL, V-104A	1	1.00E-04	5.00E-06													1.00E-04	5.00E-06
4	SHIPPING TANK, 140A				1	1.00E-05	5.00E-07										1.00E-05	5.00E-07
5	SHIPPING TANK, 140B				1	1.00E-05	5.00E-07										1.00E-05	5.00E-07
6	INDUCED GAS FLOTATION, V-102	1	1.00E-04	5.00E-06													1.00E-04	5.00E-06
7	INJECTION WATER FILTER, V-103	1	1.00E-04	5.00E-06													1.00E-04	5.00E-06
8	CLARIFIER, T-141	1	1.00E-04	5.00E-06													1.00E-04	5.00E-06
9	WATER SURGE TANK, T-143				1	1.00E-05	5.00E-07										1.00E-05	5.00E-07
10	WATER SURGE TANK, T-142				1	1.00E-05	5.00E-07										1.00E-05	5.00E-07
11	HEATER TREATER	1	1.00E-04	5.00E-06													1.00E-04	5.00E-06
12	VRU SUCTION DRUM, V-450	1	1.00E-04	5.00E-06													1.00E-04	5.00E-06
13	PIPING, 4-INCH AND SMALLER VRU DISCH DRUM, V-453 PIPING, 4-INCH AND SMALLER PIPING, 6-INCH AND LARGER	1	1.00E-04	5.00E-06							87	5.30E-05	7.96E-06	294	4.48E-05	8.96E-06	1.98E-04	2.19E-05
14	FREE WATER KNOCKOUT, V-101	1	1.00E-04	5.00E-06													1.00E-04	5.00E-06
15	AMINE FLASH TANK, V-921				1	1.00E-05	5.00E-07										1.00E-05	5.00E-07
16	3-PHASE SEPARATOR, V-932	1	1.00E-04	5.00E-06													1.00E-04	5.00E-06
17	COMPR SUCTION DR, V-901A							1	2.50E-04	3.50E-05							2.50E-04	3.50E-05
18	COMPR SUCTION DR, V-901B							1	2.50E-04	3.50E-05							2.50E-04	3.50E-05
19	PIPING, 4-INCH AND SMALLER PIPING, 4-INCH AND SMALLER 1ST STG DISCHG DRUM, V-902A 1ST STG DISCHG DRUM, V-902B PIPING, 4-INCH AND SMALLER							2	5.00E-04	7.00E-05	339	2.07E-04	3.10E-05				7.07E-04	1.01E-04
20	SULFASCRUB VESSEL, V-923A	1	1.00E-04	5.00E-06													1.00E-04	5.00E-06
21	PIPING, 4-INCH AND SMALLER										20	1.22E-05	1.83E-06				1.22E-05	1.83E-06
22	SULFASCRUB VESSEL, V-923B	1	1.00E-04	5.00E-06													1.00E-04	5.00E-06
23	AMINE ABSORBER PIPING, 4-INCH AND SMALLER	1	1.00E-04	5.00E-06							66	4.02E-05	6.04E-06				1.40E-04	1.10E-05
24	PIPING, 4-INCH AND SMALLER										160	9.75E-05	1.46E-05				9.75E-05	1.46E-05
25	2ND STG SUCT DRUM, V-903A	1	1.00E-04	5.00E-06													1.00E-04	5.00E-06
26	2ND STG SUCT DRUM, V-903B	1	1.00E-04	5.00E-06													1.00E-04	5.00E-06
27	PIPING, 4-INCH AND SMALLER 2nd STG DISCH DRUM, V-904A	1	1.00E-04	5.00E-06							120	7.32E-05	1.10E-05				1.73E-04	1.60E-05
28	PIPING, 4-INCH AND SMALLER 2nd STG DISCH DRUM, V-904A	1	1.00E-04	5.00E-06							120	7.32E-05	1.10E-05				1.73E-04	1.60E-05
29	PIPING, 4-INCH AND SMALLER COLD SEPARATOR	1	1.00E-04	5.00E-06							103	6.28E-05	9.42E-06				1.63E-04	1.44E-05
30	PIPING, 4-INCH AND SMALLER										230	1.40E-04	2.10E-05				1.40E-04	2.10E-05

4.5 Phase 4 Well Blowout Frequencies

Section 4.2.2 presented the well blowout unit frequencies; this section gives the annual well blowout frequencies for each operation.

Table 4.7 summarizes these for each Phase and Operation type. Only the maxima are given. As will be seen, these frequencies are of academic interest only, as their associated consequences of blowouts are negligible, due to the very low absolute open flow (AOF) at surface.

Table 4.7
Well Operation Blowout Frequency Summary

Phase	Well Operation	Unit Frequency	Number Units per Year	BO per Year
2	Drilling	1.01E-04	3	3.03E-04
4	Drilling maximum per year	1.01E-04	12	1.21E-03
	Completions maximum per year	7.00E-05	12	8.40E-04
	Producing maximum per year	7.41E-07	30	2.22E-05

CHAPTER 5

CONSEQUENCE ANALYSIS

5.1 Consequence Analysis: Approaches and Methodology

5.1.1 General Description of Consequence Analysis

What happens after the initial accidental release? What consequences evolve? Are these consequences fires, explosions or toxic clouds? What are their relative chances of occurrence? These questions are answered through consequence analysis [4, 8, 12].

The primary contributions to consequence analysis come from dispersion models, fire and explosion models, and effect or damage models. Source and dispersion models provide quantitative information on release rates and vapor cloud concentrations or spill characteristics and geometries. The ground-level concentration characteristics of toxic components of a gas cloud are used as a basis for toxic hazard evaluation. Fire and explosion models convert the geometric and flammability data into hazards such as thermal radiation and explosion overpressure levels. Effect or damage criteria are applied to incident-specific results to estimate casualty levels for workers or the public. Additional accuracy can be added by including consideration of mitigating factors, such as sheltering, evacuation, and protective gear, which reduce the magnitude of potential effects for the incidents considered.

Combining the results of consequence and frequency analyses leads to the quantification of risks, as discussed in the next chapter. Various measures of risk may be utilized, ranging from annual risk to specific individuals to total project risk spectra characterizing potential for groups of different numbers of people.

5.1.2 Consequence Evolution

A schematic of the sequence of events associated with different hazard scenarios for a hydrocarbon release is presented in Figure 5.1 [4, 12]. As may be seen, all hazard scenarios begin with the release of a flammable hydrocarbon which can be a gas, liquid, or a mixture of both. Liquid releases have been differentiated into high vapor pressure NGLs and low vapor pressure condensates because each class of liquid hydrocarbon behaves differently when released to the atmosphere. Clearly, in this QRA, only natural gas releases are relevant, as the crude oil effects are restricted to within the facility site. The next event shown in the hazard scenario schematic involves releases that do not ignite, but can pose acute toxic or environmental hazard. Because of the characteristics of the materials handled, acute toxic effects are also not relevant here [16, 23, 29]. Environmental impacts are discussed only for offsite releases in Chapter 7, as no onsite releases of liquids would flow offsite.

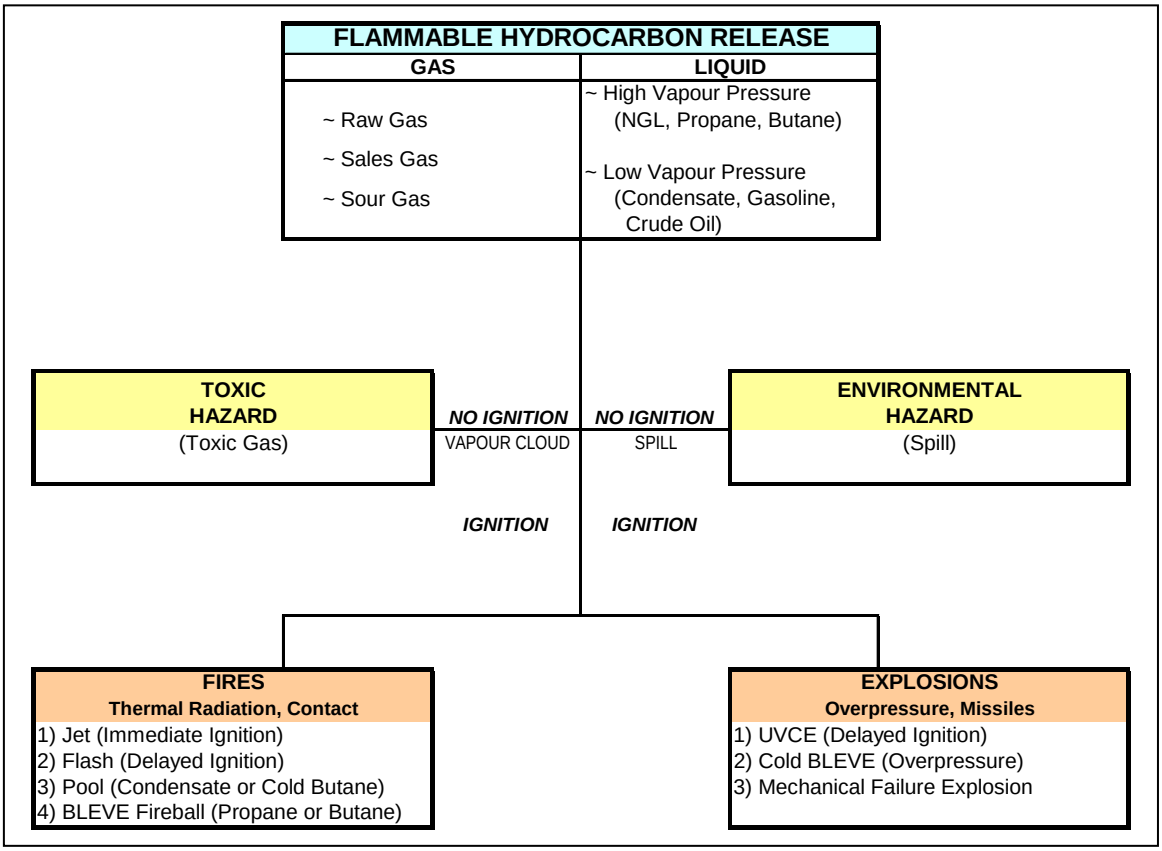


Figure 5.1
Consequence Scenarios

5.1.3 Consequence Evolution Modeling

Event trees are logic networks that illustrate and characterize the evolution of consequences from a given event. They are the opposite of fault trees, which illustrate and characterize the convergence of events leading to a given resultant. A typical event tree showing possible outcomes of a light hydrocarbon liquid release is shown in Figure 5.2. As may be seen, the trunk of the event tree on the left side gives the initiating event, the occurrence of an accidental rupture. Following this initial event, moving toward the right, a series of bifurcations show alternative consequences together with their relative probability of occurrence given as a decimal fraction.

On the far right side is given the ratio of occurrence (ROO) for each of the possible outcomes. The ratio of occurrence is obtained by sequentially multiplying the conditional probabilities of occurrence along the path leading to the outcome under consideration. For example, given that the rupture occurs, the relative likelihood of a pool fire or an unignited spill is 0.10 and 0.9, respectively. The explosion is very unlikely at a ROO of 0.008. Because the quantitative consequence evolution results from direct inputs to the risk assessment, they are specified for this project in Chapter 6, Section 6.5.

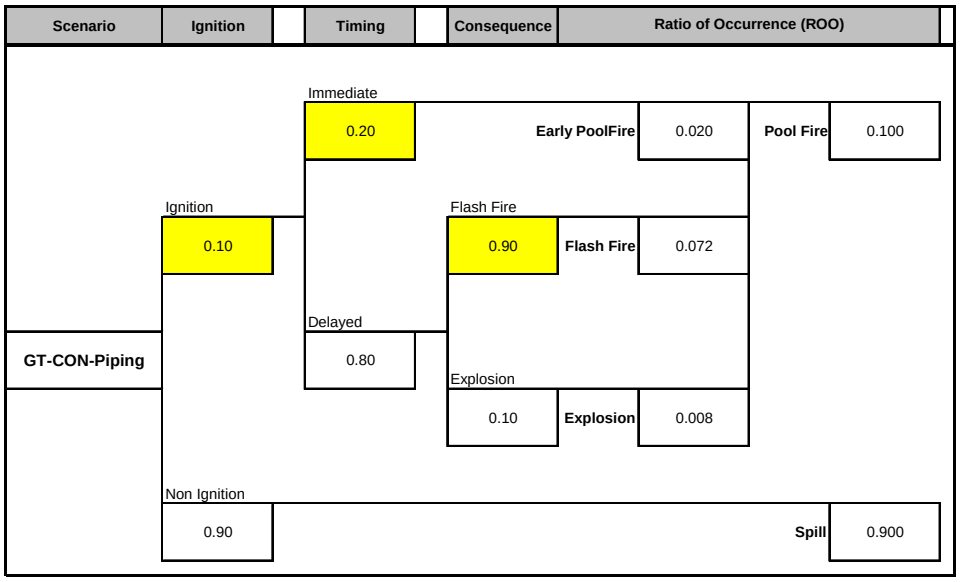


Figure 5.2
Typical Pipe Rupture Event Tree

5.1.4 Fire and Explosion Damage Criteria

Thermal radiation hazards vary with distance near a pool fire. A summary of selected effects of thermal radiation is given in Table 5.1 from [4]. "Casualties" are defined as fatalities or severe injuries. For example, the graph in Figure 5.3, based on experimental data on thermal radiation hazards was used, and shows that a thermal radiation level of 37.5 kW/m^2 is sufficient to cause 95% fatality within 30 seconds.

Direct contact with a fire, for example inside a vapor cloud flash fire, will often result in fatality. A probability of fatality of 50% was used for locations within a flash fire. For pool fire thermal radiation, the fatality levels associated with 30 second exposure based on Opschoor [30] (as shown in Figure 5.3) are normally used.

Explosion effects on people involve either direct exposure to overpressures or impact by flying debris or collapsing objects resulting from the explosion. Empirical data on blast overpressure damage is used to estimate human effect criteria for vapor cloud explosions. A summary of effects for explosion overpressures from [4] is given in Table 5.2. 60 to 100% fatality may be expected from direct human exposure to 100 kPa (15 psi) blast overpressures. Buildings, however, can be damaged if exposed to 20 kPa (2.8 psi) overpressures and therefore people inside such buildings could be harmed as a result of structural collapse. Figure 5.4 [30] gives the graph of direct overpressure fatality potential from explosions.

It should be noted that damage criteria used, together with the fatality probabilities assigned, represent worst-case conditions of exposure and effect concentration. Lesser average fatality probabilities can be expected for randomly distributed individuals in an urban landscape, due to the mitigating effects of building shields, wake effects, funneling and lateral channel flows, and other localized effects.

Table 5.1
Effects of Thermal Radiation

RADIATION INTENSITY (kW/m²)	RADIATION INTENSITY (BTU/ft²hr)	OBSERVED EFFECT	% FATALITIES AFTER 30 SECONDS
1.9	600	Will cause no discomfort for long exposure.	0
3.0	950	Severe discomfort after 60 s; 1% fatality after 240 s; 0.1% fatality after 30 s.	0.1
6.3	2000	Sufficient to cause pain to personnel if unable to reach cover within 20 s; however blistering of the skin (second degree burns) is likely; 0.5% fatality after 30 s.	0.5
9.5	3000	Pain threshold reached after 8 s; second degree burns after 20 s; 1% fatality after 30 seconds	1
12.5	3960	Melting of plastic tubing. 10% fatality after 30 seconds.	10
25	7925	Minimum energy required to ignite wood. 50% fatality after 30 seconds	50
37.5	11887	Sufficient to cause damage to process equipment. 95 % fatality after 30 seconds.	95

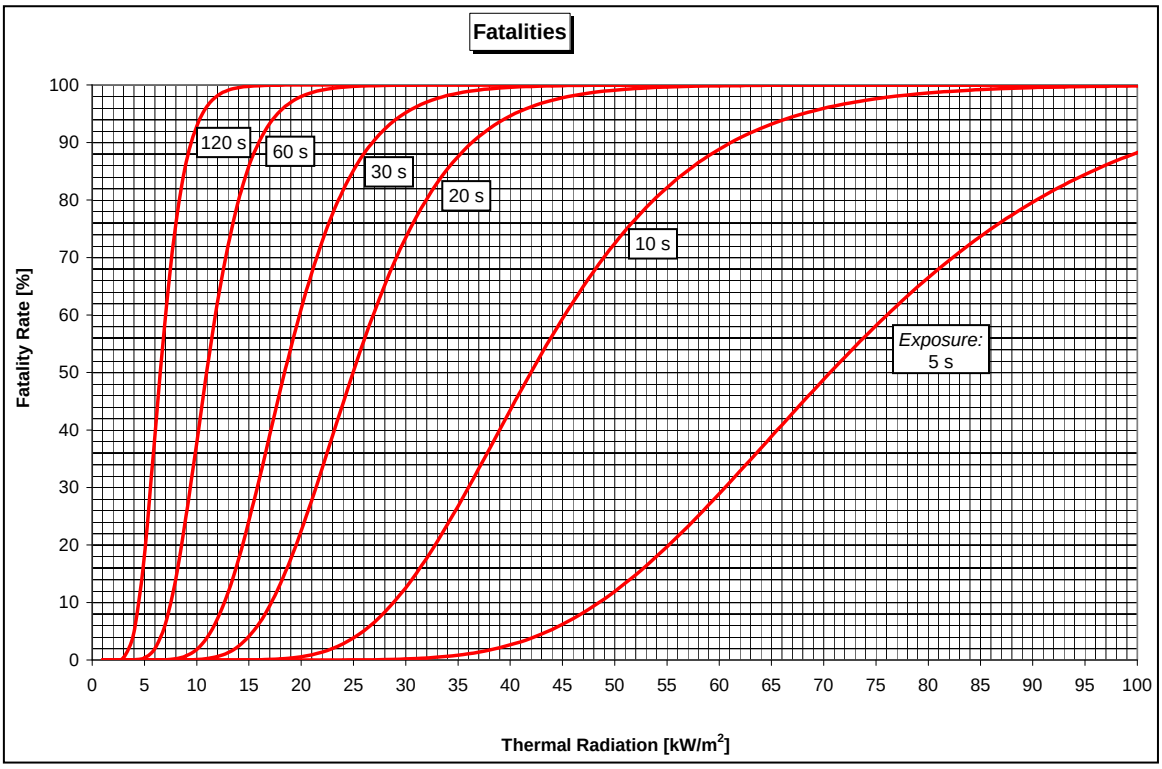


Figure 5.3
Thermal Radiation Fatality-Exposure Graph [28]

Table 5.2
Effects from Explosion Overpressures

OVERPRESSURE			OBSERVED EFFECT	% FATALITIES
(Bars)	(kPa)	(psi)		
.02	2	.3	Typical pressure for 10% glass failure. Safe distance.	0
.07	7	1.0	Damage to houses; 100% glass breakage	0
.2	20	2.8	Non-reinforced concrete or cinder block walls destroyed. (1% fatality); wood frame partial collapse	1
.25	25	3.5	Steel buildings collapse (90% eardrum rupture) (5% fatality)	5
.35	35	5.0	Wooden utility poles snapped; buildings destroyed (10% fatality)	10
1.0	100	15.0	60 to 100% fatalities among exposed populations due to direct blast effects.	60 - 100

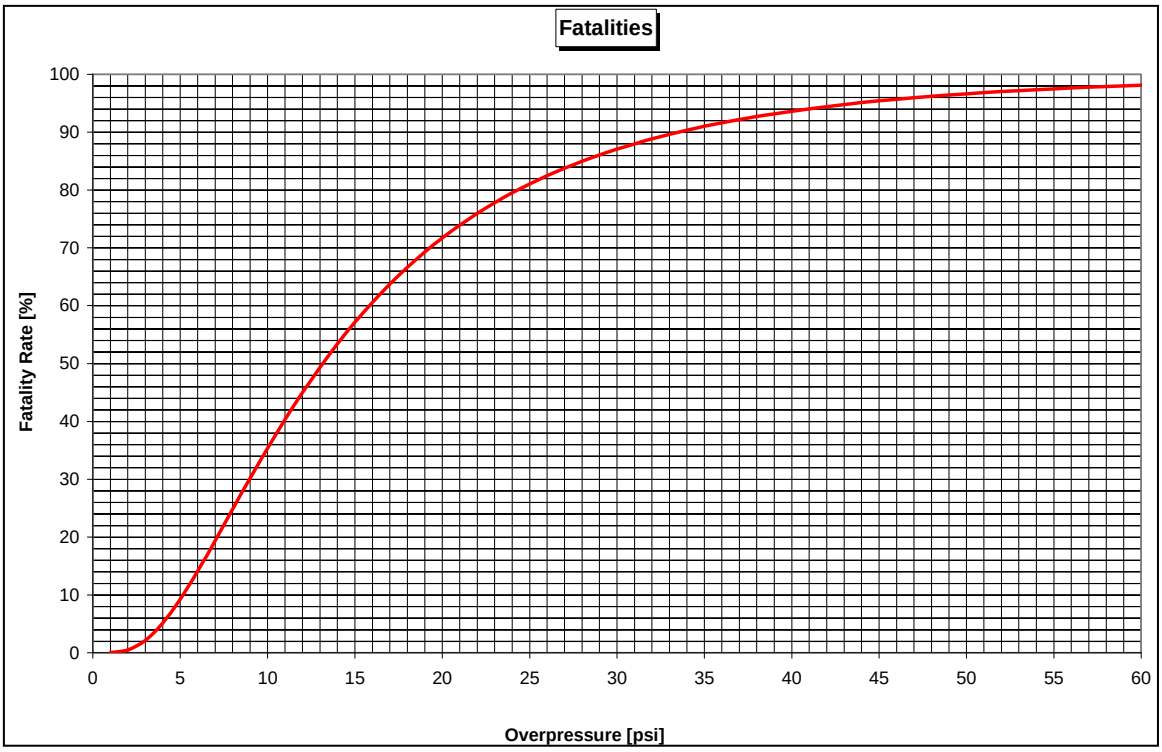


Figure 5.4
Explosion Overpressure Fatality Graph

5.1.5 Hydrogen Sulfide (H_2S) Toxicity

Acute toxic effects of H_2S occur only for relatively high concentrations, generally exceeding several hundred parts per million (ppm). As was indicated in Chapter 2, it is expected that H_2S concentrations, if any, are estimated to be a maximum of 6 ppm (Table 3.1) and the facility is conservatively designed to remove up to 100 ppm of H_2S from any produced fluids. However, in order to provide a toxicity criterion similar to those that were provided for fires and explosions, the standard probit equation for effects of H_2S toxicity at the ground level of the recipient is prevented. Specifically, the triple-shifted Rijnmond probit equation [1, 2] has generally been used to evaluate the toxic effects of higher concentrations of H_2S. Figure 5.5 shows the plot of the probit equation [1]. It can be seen that exposures of 30 minutes show 0% lethality potential for ground level concentrations of over 100 ppm. As will be shown at the end of this chapter, possible concentrations – even if produced fluids contain 100 ppm H_2S – would not exceed even 1 ppm offsite, and hence are not hazardous.

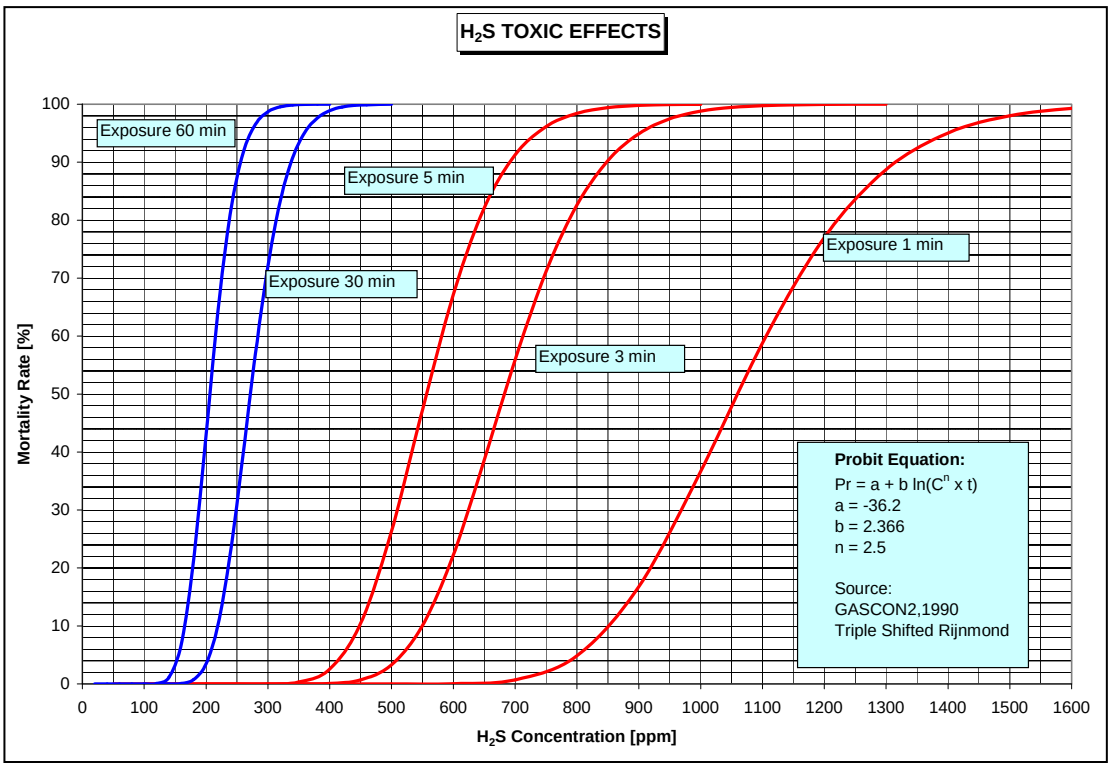


Figure 5.5
Probability of Lethality Based on Triple-Shifted Rijnmond Probit Equation for Selected Exposure Times to H_2S Concentration

5.1.6 Consequence Modeling Process

The consequence modeling process results in the quantitative description of the spatial and temporal distribution of the hazard footprint [4, 8, 12]. Hazard footprints, as indicated above, are the geometric mappings of zones in the vicinity of the hydrocarbon release associated with different levels of lethality. For example, in the case of an explosion, the limit of the 35 kPa (5 psi) overpressure zone can be depicted as a circle of a given radius (determined by the consequence model) within which a 10% casualty rate may be expected for individuals that are outdoors, and unprotected.

The spatial and temporal distribution and the characteristics of these hazard zones are assessed utilizing a consequence model. Numerous consequence models are currently available [8], both proprietary and public domain ones. Proprietary models include Chems Plus, PHAST, TRACE [34], GASCON [1], and SLAB, while perhaps the most commonly known consequence model in the public domain is ARCHIE [38], provided by the US EPA.

In this study, consequence thermal effects were modeled using TRACE [34]. This multipurpose model includes the following composite capabilities:

- Estimating the discharge rate and duration of a gas and/or liquid release from a vessel or pipeline.
- Estimating the size of any liquid pools that may form on the ground.
- Estimating the rate at which a liquid pool will evaporate or boil and the duration of these phenomena until the point in time that the pool is depleted or ignited.
- Estimating the size of the downwind hazard zone within the facility topology or on terrain for given wind and atmospheric parameters.
- The thermal radiation hazards resulting from an ignition of a flammable cloud or combustible pool of liquid.
- The size and geometry of the downwind area that may be subjected to flammable, explosive, or toxic concentrations of gases or vapors in air due to the release of a gas or vapor.
- The maximum weight of potentially explosive gas or vapor in air that occurs during a release incident.
- The consequences of an explosion arising from the internal overpressurization of a sealed or inadequately vented tank due to external heating or internal reaction.
- The consequences of an explosion arising from ignition of a true explosive material in the solid or liquid state.
- Full dispersion modeling capability including inertia, buoyancy, and multi-component gas or fluid mixtures.
- Isopleths for selected damage criteria for toxic, thermal, or overpressure effects.

5.2 Thermal Consequence Modeling Methodology

The consequence model utilized provides comprehensive results in both a tabular and graphic form for simulated release scenario consequences. Some examples of dispersion and thermal simulations are given below.

Figure 5.6 shows the natural gas dispersion isopleths for the Project NPS 4 natural gas pipeline rupture scenario (PL-R-MN), 10 seconds following a full bore rupture. One can see the extent of the Upper Flammability Limit (UFL) of 150,000 ppm and the Lower Flammability Limit (LFL) of 50,000 ppm out to 189 feet. Figure 5.7(a) shows the explosion overpressure isopleths associated with a possible natural gas explosion, which could only occur under special containment conditions. Figure 5.7(b) shows jet fire thermal levels. Such simulation products in graphic or tabular form provide the basis for the consequence analysis results described in the next sections.

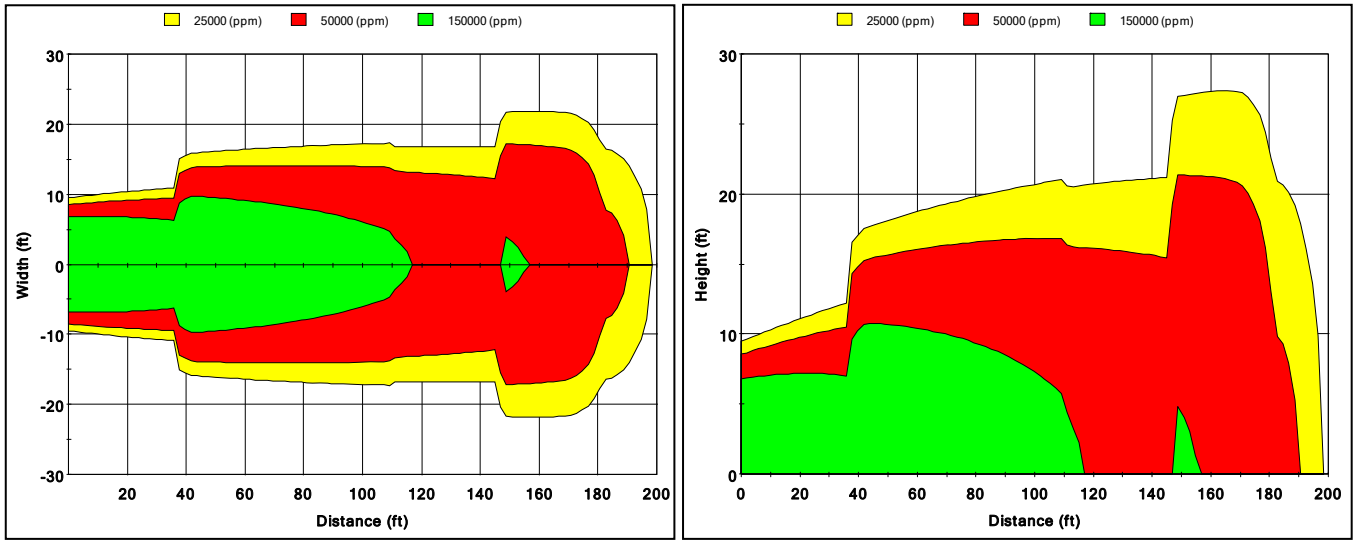
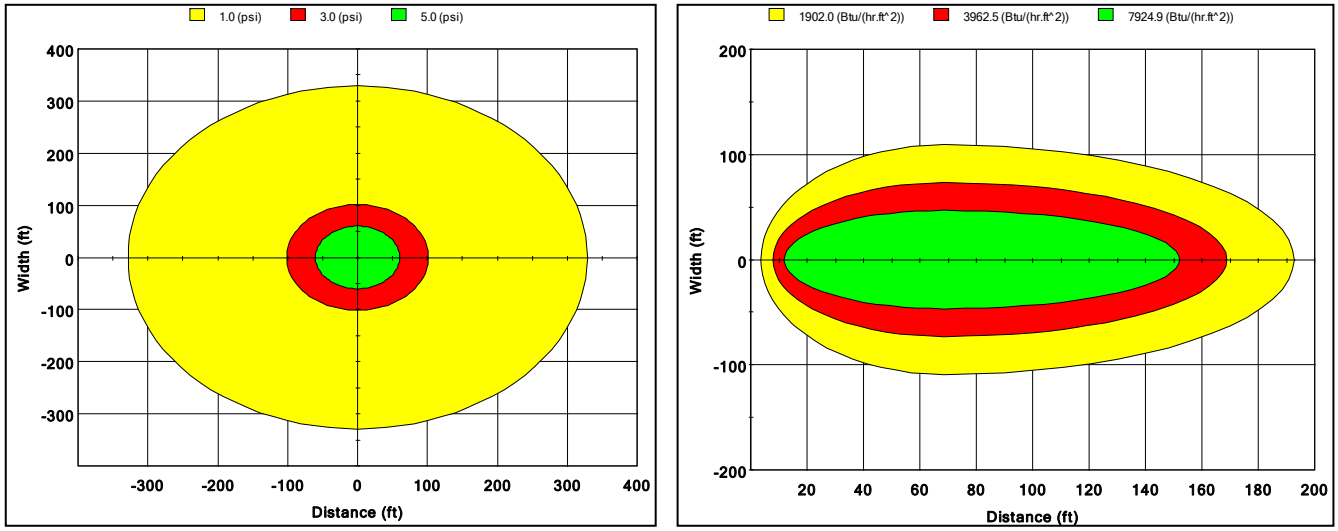


Figure 5.6
Release Cloud Dispersion Snapshots



(a) Scenario PL-R-MN Explosion **(b) Scenario PL-R-MN Jet Fire**

Figure 5.7
Natural Gas Explosion Overpressure and Jet Fire Thermal Isopleths

5.3 Phase 2 Consequence Modeling Results

Principal consequence modeling results for Phase 2 are those associated with flash fires and explosions. Pool fires, which could result in the unlikely case that an oil spill becomes ignited, would be entirely contained within the site perimeter, and accordingly, have no offsite impact. Consequence analyses were carried out for each segment for both holes and ruptures for each of three meteorological stability cases. Here, only the maximum extents which were associated with the neutral atmospheric stability condition or Pasquil stability class are summarized in Table 5.3, covering all facility and line segments as shown. For Phase 2, all Scenario acronyms are preceded by HB-P2. As can be seen, some of the results such as S07-R-MN show no onsite or offsite effect. For example, Segment 7 in scenario S07-R-MN indicates that the results of a rupture of the induced gas flotation unit, due to what is essentially atmospheric pressure at 0.1 psig, will not generate a sufficient natural gas concentration to create either an explosion or a flash fire. On the other hand, Segment 11 (the tank system), although still at low pressure, will not create a flash fire, but can generate an explosion due to the relatively large volume of natural gas that could be released into the atmosphere. In summary then, Table 5.3 gives representative worst case consequence modeling results for each of the Phase 2 segments.

Table 5.3
Typical Phase 2 Consequence Modeling Results

Segment	Consequence Scenario (HB-P2)	Maximum Isopleth Distance (ft)			
		Flash Fire LEL (ppm)	Explosion Overpressure (psi)		
		50000	1	3	5
S 4, 9, 13	S04-R-MN	0	194	60	36
S 7, 8	S07-R-MN	0	0	0	0
S 11	S11-R-MN	0	194	60	36
S17	S17-R-MN	0	0	0	0
S18	S18-R-MN	123	0	0	0
S19	S19-R-MN	0	0	0	0
L1, 2, 3, 13, 14	L01-R-MN	66	0	0	0
L 4-12, 15	L02-R-MN	0	0	0	0

5.4 Phase 4 Consequence Modeling Results

On the same basis as the results for Phase 2, the Phase 4 representative worst case results are presented in Table 5.4; again consequence analyses were carried out for each segment for both holes and ruptures for each of three meteorological stability cases, and integrated into the final results. All Phase 4 scenario acronyms are preceded by HB-P4. Comments similar to those relating to Phase 2 can be made here in regard to the variable effects of the different segments. Again, one can see that low pressure, low volume segments will have no onsite or offsite impact, while the higher pressure or higher volume segments have a potential offsite impact. In general, it can be seen that because of the larger volumes of fluids handled in Phase 4, the hazard or maximum isopleth distances extend out further than those for Phase 2. In the case of explosion overpressures, one can see maximum extents of the 1 psi isopleth out to 398 feet, while maximum reach for this

isopleth for Phase 2 is 194 feet. Finally, flash fires can occur out to over 250 feet, whereas for Phase 2, these only extend to roughly 120 feet.

Table 5.4
Typical Phase 4 Consequence Modeling Results

SEGMENT	Consequence Scenario (BH-P4)	Maximum Isopleth Distance (ft)			
		Flash Fire LEL (ppm)	Explosion Overpressure (psi)		
		50000	1	3	5
1	S01-R-MN	0	0	0	0
2	S02-R-MN	0	0	0	0
3	S03-R-MN	0	0	0	0
4	S04-R-MN	0	393	121	72
5	S05-R-MN	0	393	121	72
6	S06-R-MN	0	0	0	0
	S07-R-MN	71	0	0	0
8	S08-R-MN	0	398	123	73
9	S09-R-MN	0	324	100	59
10	S10-R-MN	0	324	100	59
11	S11-R-MN	0	214	66	39
12	S12-R-MN	0	0	0	0
13	S13-R-MN	105	214	66	39
14	S14-R-MN	100	269	83	49
15	S15-R-MN	55	0	0	0
16	S16-R-MN	207	0	0	0
17	S17-R-MN	53	0	0	0
18	S18-R-MN	53	0	0	0
19	S19-R-MN	205	207	64	38
20	S20-R-MN	205	246	76	45
21	S21-R-MN	97	0	0	0
22	S22-R-MN	0	0	0	0
23	S23-R-MN	185	220	68	40
24	S24-R-MN	78	0	0	0
25	S25-R-MN	78	0	0	0
26	S26-R-MN	78	0	0	0
27	S27-R-MN	251	205	63	37
28	S28-R-MN	251	205	63	37
29	S29-R-MN	251	205	63	37
30	S30-R-MN	251	205	63	37

5.5 Natural Gas Pipeline Consequence Modeling Results

The natural gas pipeline, an NPS 4 line, following blowdown calculations for holes and full ruptures, was modeled for flash fires, explosions, as well as jet fires. In the case of the facilities, due to the perimeter wall, it was concluded that jet fires would have no offsite impact, whereas for the pipeline, in the instance of a hole or rupture with either auto-ignition or near immediate ignition, a jet fire would result. Table 5.5 gives flash fire, jet fire, and explosion overpressure isopleths for the natural gas pipeline, for both holes and full ruptures, for each of the three atmospheric stability classes. Again, scenario acronyms start with HB-NG for the natural gas pipeline.

Table 5.5
Natural Gas Pipeline Consequence Modeling Results

Scenario (HB-NG)		Maximum Isopleth Distance (ft)						
		Flash Fire LEL ppm	Jet Fire Thermal Radiation (Btu/hr ft^2)			Explosion Overpressure (psi)		
		50000	1902	3963	7925	1	3	5
Hole	PL-H-MU	76	61	54	50	226	70	41
	PL-H-MN	46	51	45	40	226	70	41
	PL-H-MS	89	64	57	53	226	70	41
Full Rupture	PL-R-MU	168	224	200	183	329	101	60
	PL-R-MN	189	193	167	152	329	101	60
	PL-R-MS	166	235	211	193	329	101	60

5.6 Sour Gas Release Consequence Modeling Results

In order to demonstrate the effects of a possible blowout or uncontrolled flow from one of the exploration, production, or workover wells, consequence modeling was carried out for the worst case scenario. According to E&B Resources [20], the maximum absolute open flow (AOF) at surface for a well would be a rate of approximately 460 bbl of oil per day with a maximum natural (sour) gas rate of 139,840 standard cubic feet per day (SCFD), but over the blowout period of 14 days, averaging approximately 40,000 SCFD. Once again, it is the gas that is of concern. Assuming that the natural gas had an H_2S content of 100 ppm (the limit of the facility sweetening capability), the AOF was modeled to provide ground level H_2S concentrations at various distances for each of the three atmospheric stability classes. The results of the model giving ground level H_2S concentrations are presented in Figures 5.8, 5.9, and 5.10. It must be emphasized that the concentrations shown in these concentration graphs are in parts per billion (ppb), and not parts per million (ppm). That is, they are one thousand times less than the equivalent concentrations in parts per million. All graph scales are kept the same for easy comparison. For the largest extent of the dispersion isopleth, such as that shown in Figure 5.10, for stable atmospheric conditions, it can be seen that the 100 ppb extends out to approximately 280 feet. Translating this into parts per million, this indicates that an H_2S concentration of 0.1 ppm could occur out to 280 feet. This concentration is well below any lethality limit, as well as below the offensive odor threshold, which is 1 ppm. Clearly, the expected concentrations of roughly 6 ppm at the source – rather than 100 ppm as has been modeled here – would give much lower, but equally Insignificant H_2S ground level concentrations offsite. The expected maxima of 6 ppm H_2S also would classify the natural gas as sweet, and not sour (which requires concentrations greater than 50 ppm).

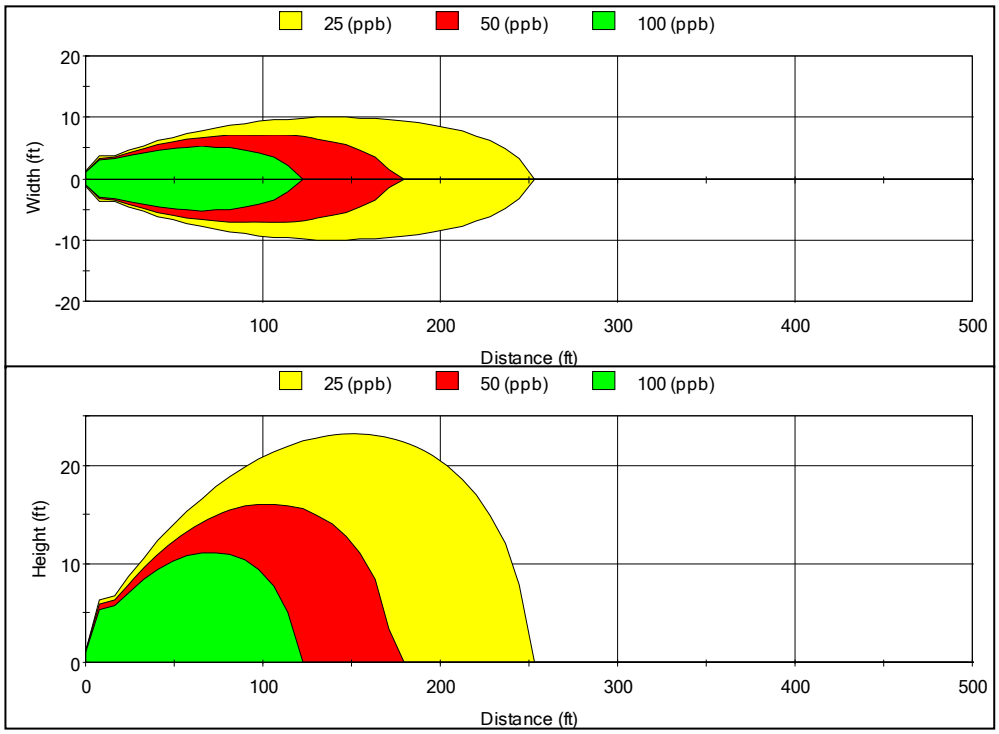


Figure 5.8
Well Blowout Steady State Release Isopleth – Unstable Atmosphere

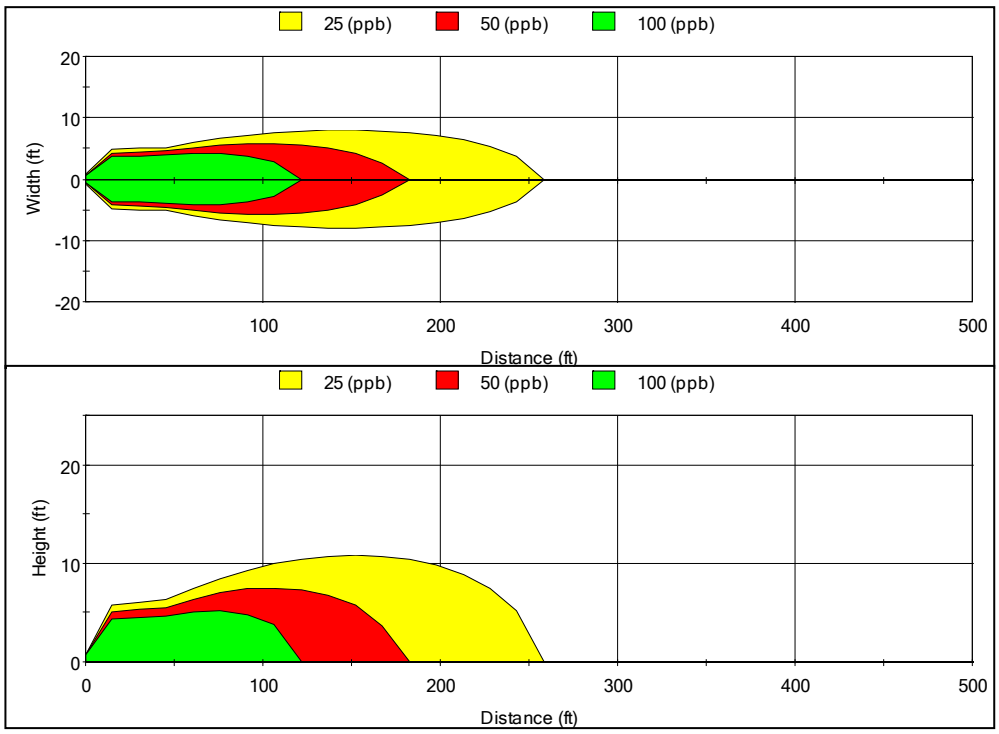


Figure 5.9
Well Blowout Steady State Release Isopleth – Neutral Atmosphere

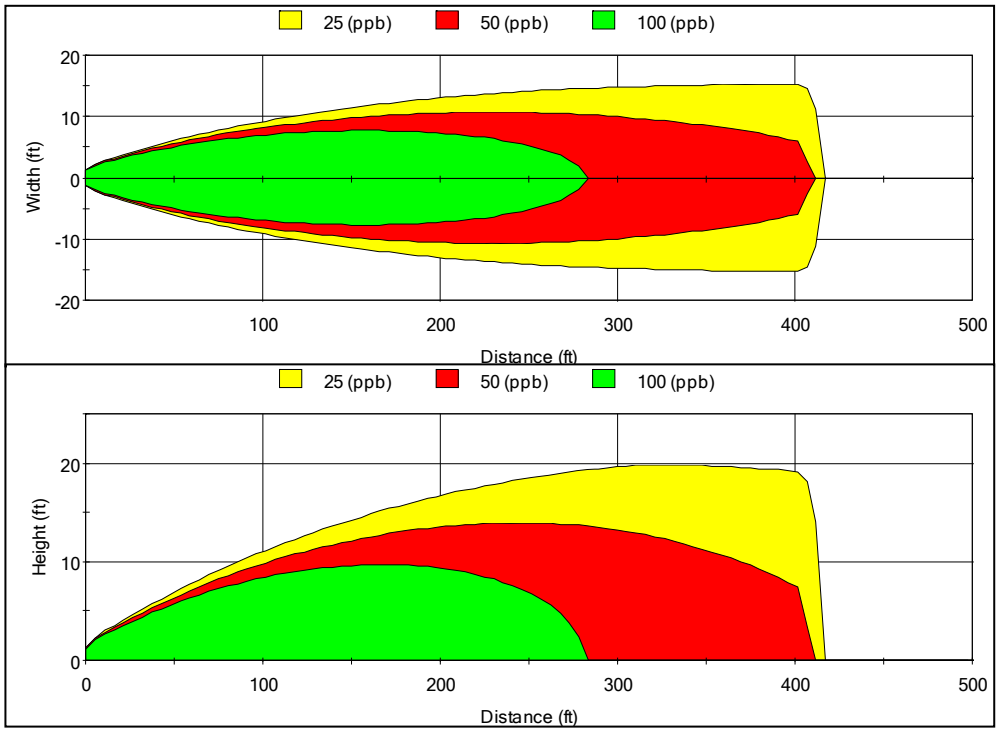


Figure 5.10
Well Blowout Steady State Release Isopleth – Stable Atmosphere

CHAPTER 6

RISK ASSESSMENT

6.1 Approaches to Risk Assessment

In the previous three chapters, the assessments of hazards, frequencies, and consequences were described. This preceding work was done without regard to specific population distributions and the likelihood that they would be indoors or outdoors. In this chapter, the results of the frequency and consequence analyses are integrated with an estimate of the likely population exposure to provide measures of public risk.

Both individual and collective risks for the proposed Project are quantified herein. The measure of individual risk used in this QRA is Individual Specific Risks (ISR) at a specific location. Individual Specific Risks or ISR are the actual risks to a specific individual at a given location resulting from the Project's operation over a one-year period [4, 7, 12]. ISR takes into account both the amount of time the individual spends at the location within the zone of influence of the Project and the proportion of time that the individual is outdoors and indoors. ISRs can be expressed as risk transects, which illustrate the variation in ISR magnitude with distance from the risk source. Collective risks, also quantified here, give the risks to any number of individuals in the Project hazard zone, but still consider their presence and exposure.

6.2 Public Risk

6.2.1 Individual Risk

Individual Risk Intensity (IRI) for a given location is defined as the probability that a normal adult individual will become a casualty if that individual remains outdoors continuously (24 hours a day, 365 days per year) at that location for one year. IRI, sometimes also called the Individual Risk Field, thus defined forms an upper bound to other measures of individual risk such as Individual Specific Risk (ISR) or Average Individual Risk (AIR). Any other measure of individual risk for similar individuals is likely to be lower due to the introduction of mitigating factors such as reduction in time spent at the location, sheltering through indoor residence, use of protective gear, or evasive action. The upper bound IRI quantified herein, has the advantage that it is a clearly defined quantity which can be used as a basis for computation of any other measure of individual risk without major factoring or manipulation**. Individual Specific Risk (ISR) for a given location is defined as the probability that a normal adult individual will become a casualty considering the actual proportion of time spent outdoors and indoors at the location.**

Computation of individual risk can be conducted for two different types of sources; namely, point sources and linear sources.

For point sources, such as production wells, the Individual Risk Intensity (IRI) is computed as follows:

$$IRI_p = P_R \cdot P_S \cdot P_F \cdot P_D \qquad \textbf{(6.1)}$$

where,

IRI_p = IRI for point source
P_R = probability of release per year
P_S = conditional probability of scenario occurrence (ROO from event trees)
P_F = probability of fatality
P_D = probability of hazard occurring in direction D

For linear sources, such as pipelines, on the other hand, the IRI is computed by:

$$IRI_L = P_R \cdot P_S \cdot P_F \cdot P_D \cdot L_I \quad \textbf{(6.2)}$$

where,

$$L_I = 2\,(H^2 - X^2)^{1/2} \quad \textbf{(6.3)}$$

where,

IRI_L = Individual Risk Intensity for a linear source
P_R = linear probability of release per km-yr
P_S = conditional probability of scenario occurrence (ROO)
P_F = probability of fatality
P_D = probability of hazard occurring in direction D
L_I = interaction length of pipeline
H = extent of hazard footprint from location of release at pipeline
X = distance to receptor, perpendicular to pipeline centreline

For either linear or point sources, the ISR, the actual risk to which a specific individual is subjected, is computed as follows:

$$ISR = IRI \cdot P_L\,(P_O + R_I \cdot P_I) \quad \textbf{(6.4a)}$$
$$= IRI \cdot ISRF \quad \textbf{(6.4b)}$$

where,

P_L = Probability of being at location
P_O = Probability of being outdoors (exposed)
P_I = Probability of being indoors
R_I = Reduction of exposure due to being indoors
ISRF = Individual Specific Risk Factor

The above formulas are embedded in spreadsheets to generate base data for plotting individual risk transects.

The spreadsheet approach, embedding Equation 6.1, is used for the computation of individual risk from facility equipment sources; Equation 6.2 is used for pipeline sources. This facilitates calculation of individual risk at various distances for each of the consequence scenarios associated with each system. The appropriate representation of risk for either a point or linear source is a risk transect, showing the variation in risk with the distance on either side of the source, as illustrated in Figure 6.1. Representative values of the risk transects can be plotted as representative risk contours in a facility plan view, as will be shown later.

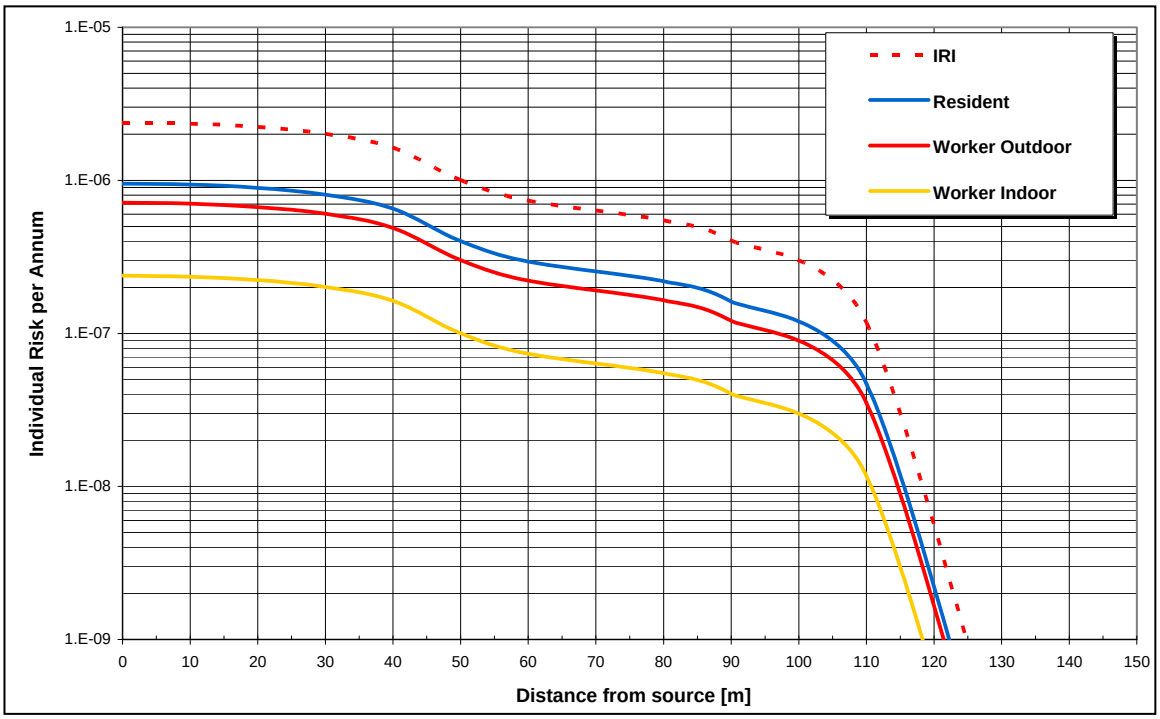


Figure 6.1
Typical Individual Risk Transect

6.2.2 Collective Risk

Collective or group risk results are usually represented as risk spectra. A risk spectrum is a graph of the frequency of occurrence and the number, N, of individuals involved in the occurrence, with the frequency given on the vertical axis and the number of individuals on the horizontal axis. Specifically, the graph represents the probability that N or more (or at least N) individuals will become casualties in any given situation [4, 12].

6.3 Public Safety Risk Thresholds

Risk is a combined measure of the probability and magnitude of adverse effect. Risk thresholds are a term generally used to designate the levels of risk which are acceptable in certain situations. Possible measures of risk include individual risk, risk expectations, and risk spectra. Individual risk is simply the probability that a given individual will become a casualty as a result of the Project over a period of exposure of 1 year. Collective Risk expectation can be described by the use of a risk matrix which relates various discrete levels of likelihood of occurrence and severity of consequences to people or the environment. A more rigorous assessment of collective risk, a risk spectrum, gives a continuous relationship between the probability of occurrence and a quantitative measure of the severity of consequences, such as the number of people affected.

6.3.1 Individual Specific Risk Thresholds

Individual risk is usually expressed in terms of an annual probability of death for the exposed person. This individual risk measure is termed Individual Specific Risk (ISR). An annual probability (or chance) of death of 1 in 1,000,000 is often taken as an acceptable level [12]. A distinction is often made between voluntary and involuntary risk; voluntary risk is considered to emanate from activities we undertake by choice such as motor vehicle driving; involuntary risks are those from sources over which we have no control such as tornadoes or living next to an industrial facility. The distinction is somewhat academic, however, as often we have no choice in taking a voluntary risk such as driving, as we need to incur it to make a living; similarly, technically, we have the choice of moving to where there are no tornadoes. Figure 6.2 summarizes accidental ISR for a typical North American resident from common everyday sources and activities [12]. It is somewhat surprising that unnecessary medical error risks in North America [39] surpass those associated with motor vehicle accident risks.

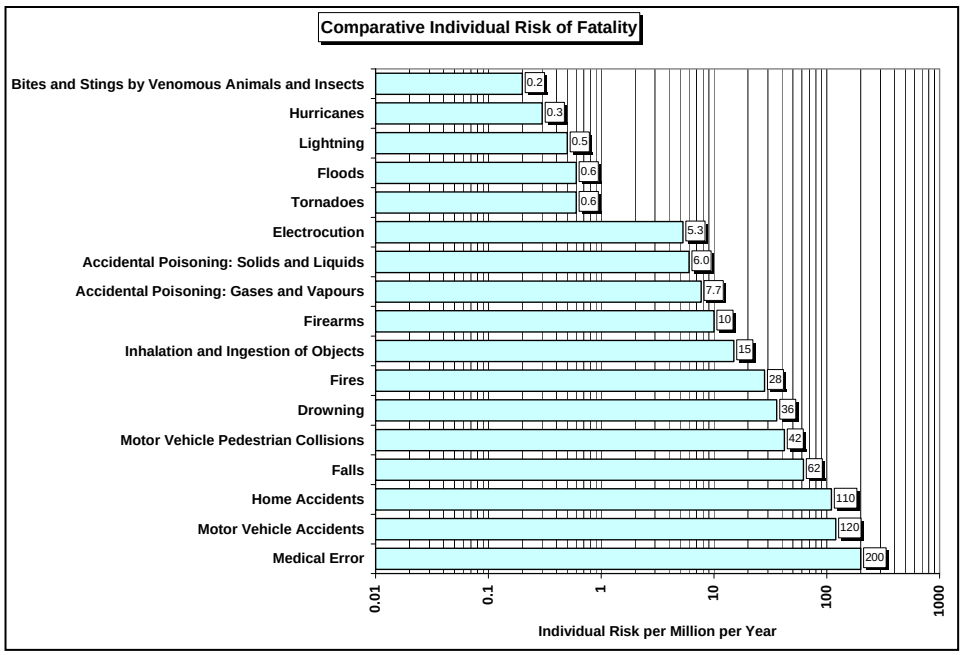


Figure 6.2
Comparative Individual Risks of Fatality

A workable set of guidelines for individual risk thresholds is based on Individual Specific Risks (ISR) – the actual risks to which specific individuals are subjected considering time spent at a given location and the proportion of that time spent indoors [4, 7, 12, 35, 36]. There are three principal regions within which public risks are designated, depending on their level or intensity. The highest region is the Unacceptable region, which is simply intolerable. The next region is the Grey region, in which risks should be reduced in accordance with optimal risk-beneficial activities and subject to regulatory discretion. And finally, there exists the Insignificant risk region, in which risks are always considered acceptable. The following hierarchy of Individual Specific Risk (ISR) levels is proposed herein for third party or public risks:

- Unacceptable: ISR $\geq 10^{-4}$
- Grey: $10^{-4} > ISR > 10^{-6}$
- Insignificant: ISR $\leq 10^{-6}$

ISR levels of acceptability for Project employees are often up to one order of magnitude higher; that is, the Insignificant level could be ISR $\leq 10^{-5}$.

6.3.2 Risk Matrix Thresholds

The risk matrix is a semi-quantitative display of the severity and frequency of different adverse consequences with the areas of increasing significance in terms of risk depicted on Figure 6.3. Events within the shaded area are considered significant and should be mitigated, while those in the unshaded area are considered Insignificant. Numerous forms of the risk matrix have been used worldwide, based on the same principles as the County of Santa Barbara risk matrix, shown in the figure below [17, 18]. The matrix shown includes public safety criteria which were later (1997) superceded by the risk spectrum discussed in the next section.

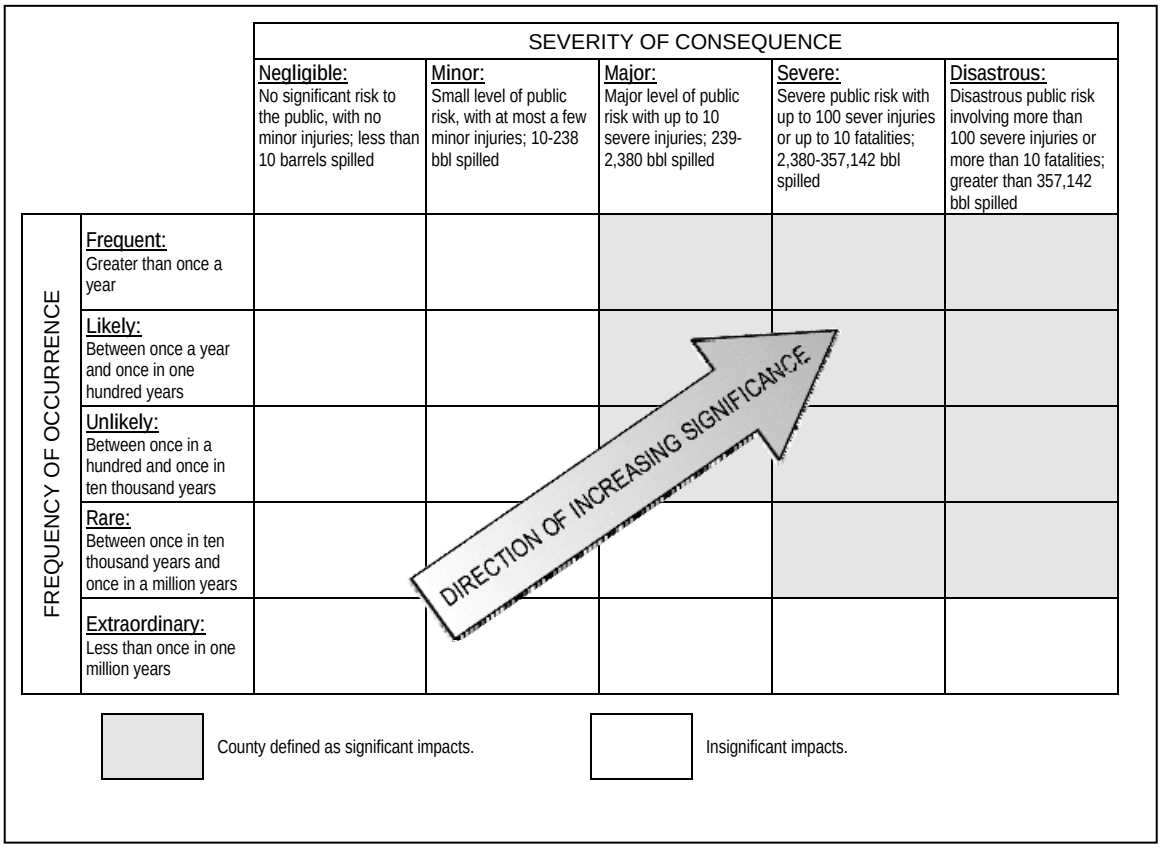


Figure 6.3
Santa Barbara Risk Matrix [17]

6.3.3 Collective Risk Spectrum Thresholds

A risk spectrum, relating the probability to the associated expected number of casualties, is often used as a measure of group risk. The risk spectrum is a convenient graphical display of the variation in probability with the magnitude of consequences for a given risk scenario. It is plotted on log-log paper with the vertical axis giving the probability and the horizontal axis, the associated **minimum** number of people affected; that is, the risk spectrum is a probability of exceedance graph giving the probability that *at least N people are at risk*.

Figure 6.4 shows the collective risk of fatality thresholds on an F-N curve or risk spectrum as adopted in the County of Santa Barbara [11], with a hypothetical project plotted to show how it is used. Note that the numbers on the vertical axis are presented in exponential notation, where, for example, 1.00E-03 = 10^{-3}, as described in Section 1.5 of Chapter 1. The registration of the risk spectrum assessed for a specific project as shown with respect to the above set of collective risk thresholds is an indication of the level of acceptability of project risks. Clearly, the example project is in the "Grey" region, where it's acceptability is subject to cost-benefit. A somewhat higher set of thresholds (up to one order of magnitude) is often used for project personnel.

Finally, either individual or collective risks for an entire project life cycle are called Life Cycle Cumulative Risks.

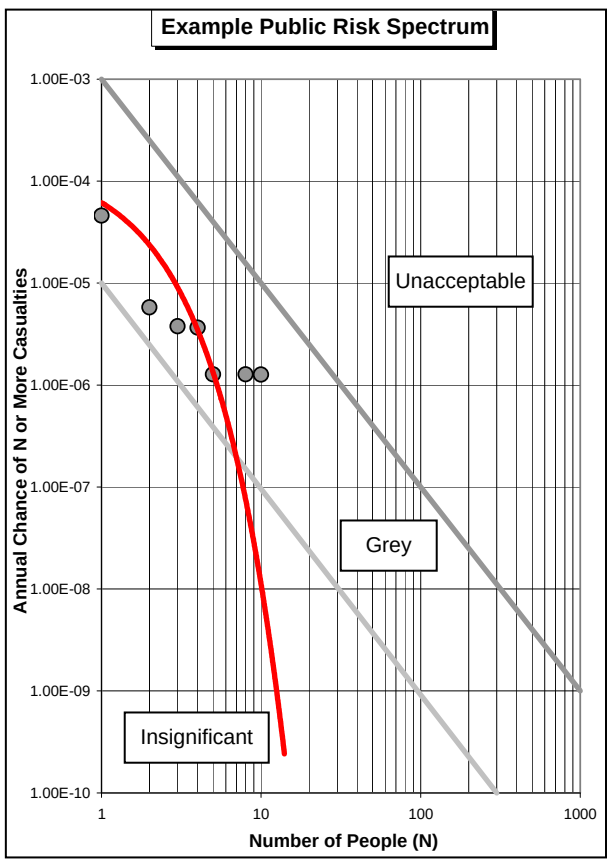


Figure 6.4
Typical Collective Risk Thresholds on a Risk Spectrum

6.4 Hydrogen Sulfide (H_2S) Risks

It has been reported by E&B that potential hydrogen sulfide (H_2S) in the order of 0.0 to 6.0 parts per million (ppm) are anticipated to be encountered in the natural gas produced from the subject reservoirs. However, in order to have the capability to treat higher levels, the proposed Project has been planned to routinely treat H_2S levels of 15 ppm, and has a maximum design capacity to treat H_2S levels of up to 100 ppm. To provide an assessment that addresses the worst-case scenario, an H_2S level of 100 ppm was considered here and modeled in Section 5.6. A summary of the background on risks associated with H_2S is provided in the balance of this section.

Hydrogen Sulfide (H_2S) gas is known to be physiologically damaging to humans when ingested usually through breathing in sufficient quantities. In the hydrocarbon industry, H_2S occurs naturally in reservoirs and is produced with methane or natural gas as well as crude oil in varying concentrations. When H_2S is present in a fluid in sufficient quantities, the fluid is termed "sour". Quantitative assessments of the damage from H_2S are available for acute or immediate lethality effects; long term or chronic effects are not completely understood and continue to be a subject of controversy worldwide. The current analysis was restricted to the analysis of acute effects of H_2S. The nature of the damage to a given individual due to exposure to a toxic gas depends on the dosage, which is the concentration and exposure time.

The effects of H_2S on exposed individuals vary depending on exposure time, concentration, and sensitivity of the person. General health effects of H_2S exposure to different concentrations of H_2S in air are summarized in Table 6.1.

Table 6.1
General Health Effects of H_2S

Concentration in Air (ppm)	Health Effects
0.01 to 0.3	Odour threshold, minimum concentrations one can smell
1 to 5	Moderate to strong offensive odour; may create nausea, tearing of the eyes, headaches, or loss of sleep following prolonged exposure - effects are moderate.
10	8-hour Occupational Exposure Limit
20	Ceiling Occupational Exposure Limit, and evacuation level
20 to 50	Slight eye and lung irritation - may cause eye damage after several days of exposure; may cause digestive upset and loss of appetite.
100	Eye and lung irritation after several days.
150	Kills sense of smell; severe eye and lung irritation after two days.
500	Serious damage to eyes within 30 minutes; severe lung irritation; unconsciousness and death within 4 to 8 hours.
1000	Fatality within 3 minutes.

The concentrations given in this table are the concentrations at the receptor location; that is they are the concentrations in air that the receptor contacts and inhales. They are not the source concentrations which can be significantly higher but become diluted as the H_2S mixes with air while traveling and dispersing toward the receptor. At low concentrations (0.01 to 0.3 ppm) at the receptor, H_2S creates a perceptible odour similar to that of rotten eggs, which becomes quite offensive if concentrations exceed 1 ppm; the odour prevails until concentrations of 150ppm. As concentration and/or exposure time increases, the severity of the health effects also increases. For example, an exposure to between 20 and 50 ppm may cause eye damage after several days but such a concentration is not considered sour. Concentrations of 200 ppm can cause injury after two or more days of exposure. Acute physiological damage, however, including serious eye damage, occurs for concentrations greater than 500 ppm over a period of approximately 30 minutes, with fatality after several hours of exposure. Concentrations of 1,000 ppm or greater are life-threatening for very short exposures.

To address the possible worst-case identified by the proponent, it was assumed that 100 ppm of H_2S could occur in the produced gas and any accidental releases would be short duration. Concentrations of H_2S at offsite locations would be much lower than 100 ppm, as they decrease with distance from the release point. As was rigorously shown in Section 5.6 of Chapter 5, in the case of a well blowout, the maximum offsite ground level concentration of H_2S would be in the order of 100 ppb or 0.1 ppm, well below the lethality level for any length of exposure time. From Table 6.1, it can be seen that short term exposure to H_2S concentrations of 100 ppm poses no risks of either lethality or injury from short durations of exposure, and 0.1 ppm is only within the odor threshold and poses no known lethality risk for any length of exposure. As was shown in Section 5.6, H_2S concentrations of potential releases would be well within non-lethal levels at the facility, and even lower offsite, never exceeding 1.00 ppm. Accordingly, no acute risk from H_2S exposure from the proposed Project is possible.

6.5 Consequence Evolution

As described in Section 5.1.3, consequence evolution modeling utilizing event trees is used to obtain the relative probabilities of different hazardous outcomes of a specific hazardous event. In this case, as was indicated earlier, the principal hazard results from the release of flammable gas from either the facility or the natural gas pipeline.

Figure 6.5 shows a consequence evolution event tree used for the proposed Project. As can be seen, potential outcomes include jet and flash fires, explosion and dispersion. As indicated earlier, jet fires are only considered to have offsite impacts if they occur in conjunction with a loss of containment with a natural gas pipeline; onsite, a jet fire if it occurred would not have effects outside the perimeter wall. The ratios of occurrence (ROO) calculated in the event tree are then input into the BRISC integration software [12], and permit the calculation of the risk associated with various segments and their integrated resultant.

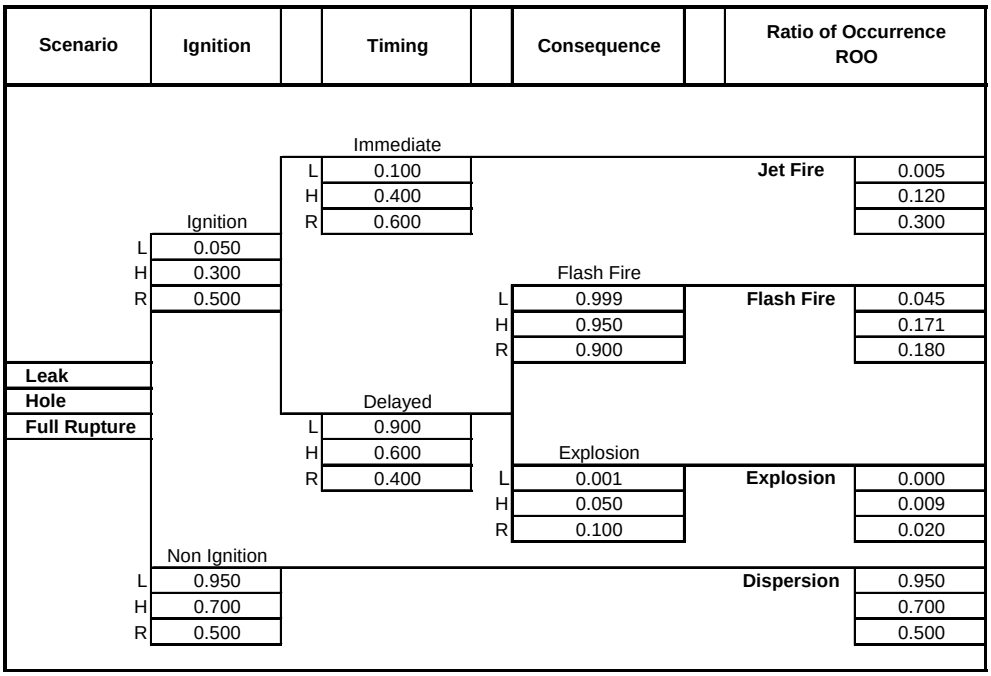


Figure 6.5
Consequence Evolution Event Tree

6.6 Phase 2 Risk Assessment

To define the integrated risks, the effects of each of the 25 segment releases for both holes and ruptures, for 3 meteorological cases and 4 wind directions were integrated to provide a measure of the variation of risk with distance from the facility center. Thus, a total of 450 scenarios were integrated to provide the risk transects, and later the risk spectrum. The integrated risk transects for all Phase 2 process segments and the interconnecting pipe segments are shown in Figure 6.6, as the best fit lines for each of the principal wind directions. It should be noted that the risk from a specified wind direction occurs in the opposite direction; thus, the westerly wind risks are exacerbated in the easterly direction. It should be noted that the transects shown are for the individual risk intensity or risk field, which is the maximum possible risk without considering onsite dwell time and exposure. A summary of the distances for the risk intensity and for the resident individual specific risks are given in Table 6.2 and 6.3 respectively. As the distances are measured from the risk centroid at the facility location, given the shortest distance to the perimeter of approximately 100 feet, one can see that offsite risks are significantly less than 1 in 1 million, commencing at roughly 100 feet in the westerly direction at a value of approximately 1 in 100 million or 1.00E-08. A plan of the risk contours is given in Figure 6.7. The resultant risk spectrum, considering the population distribution generally described in Section 2.4, augmented with the appropriate number of transient workers and other transients, is shown in Figure 6.8, with the probability vertical axis given as occurrences per million. Clearly, the entire risk spectrum for Phase 2 is in the Insignificant region.

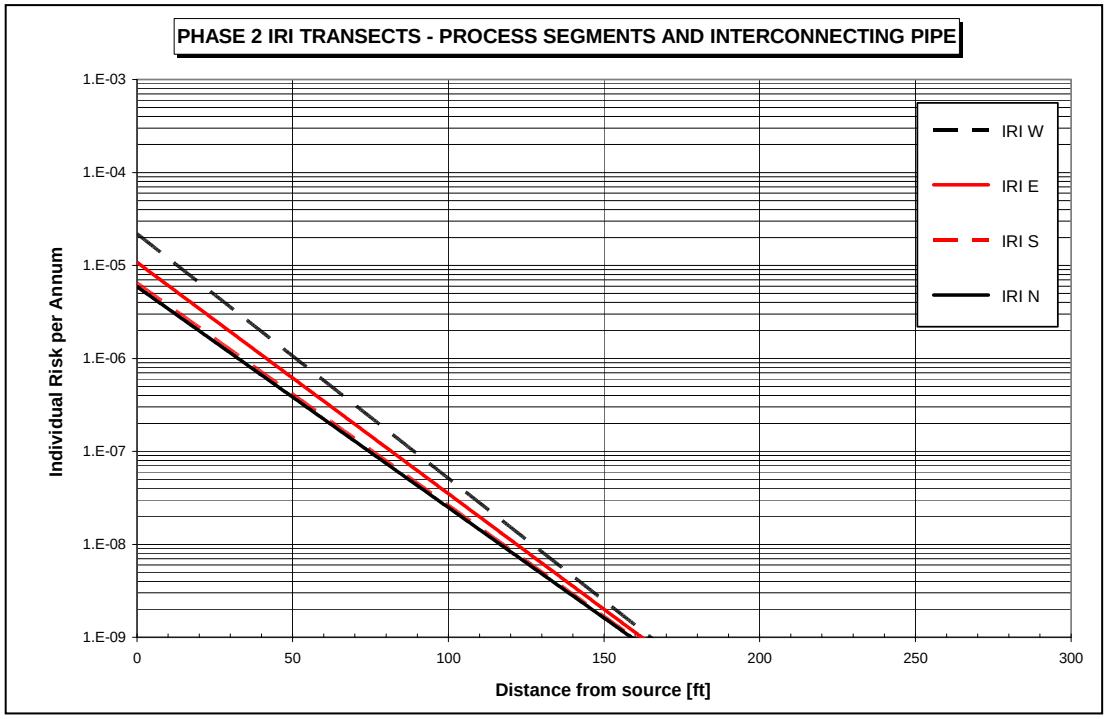


Figure 6.6
Phase 2 IRI Transect

Table 6.2
Phase 2 IRI Risk Distance

Wind Direction	IRI Risk Distance [ft]					
	1.00E-04	1.00E-05	1.00E-06	1.00E-07	1.00E-08	1.00E-09
N	0	0	32	75	117	159
E	0	1	42	82	122	162
S	0	0	34	76	118	159
W	0	13	51	89	127	165

Table 6.3
Phase 2 Resident ISR

Wind Direction	Resident ISR Risk Distance [ft]					
	1.00E-04	1.00E-05	1.00E-06	1.00E-07	1.00E-08	1.00E-09
N	0	0	0	36	81	125
E	0	0	3	46	88	130
S	0	0	0	38	82	126
W	0	0	15	55	95	135

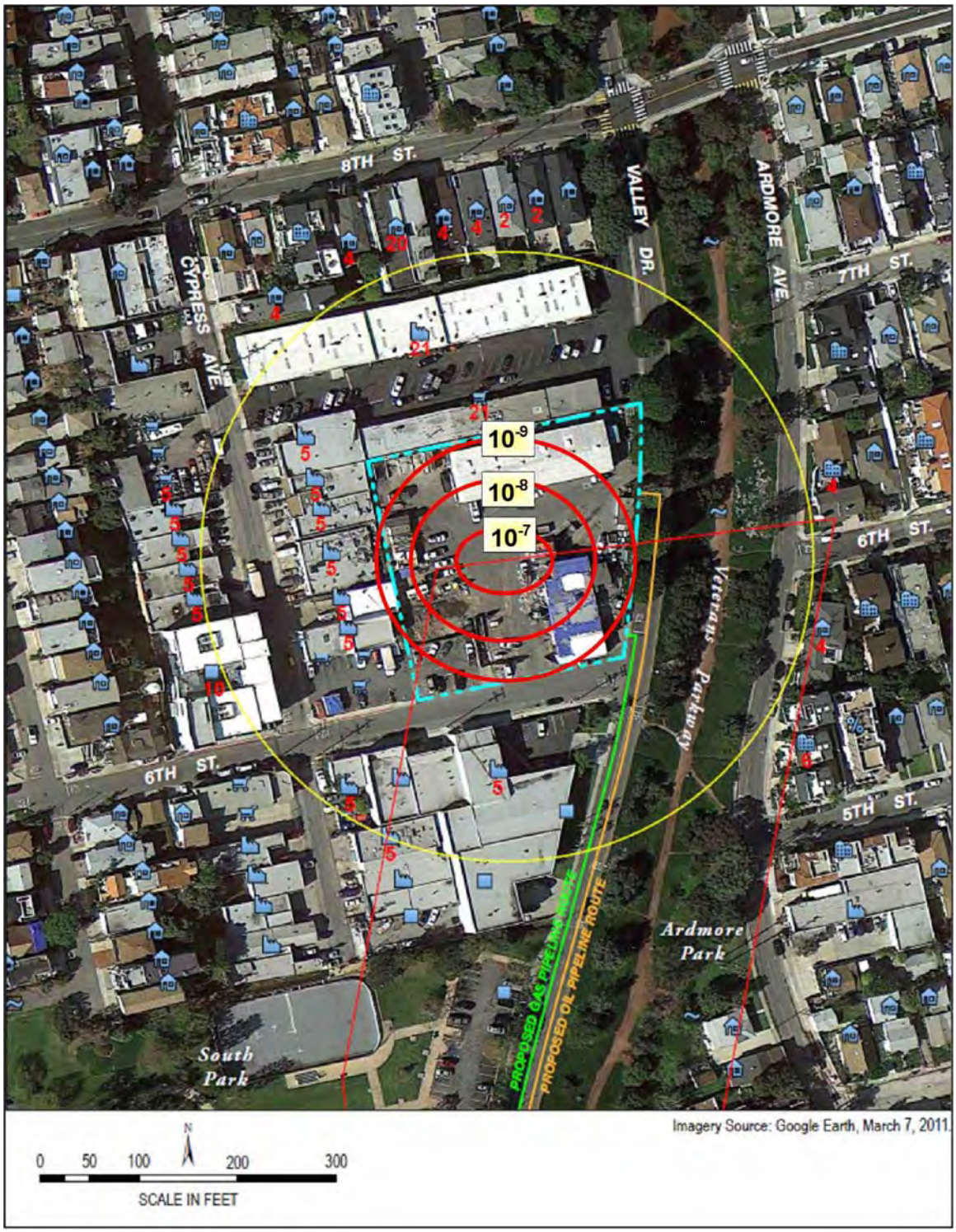


Figure 6.7
Phase 2 Resident Individual Specific Risk Contours

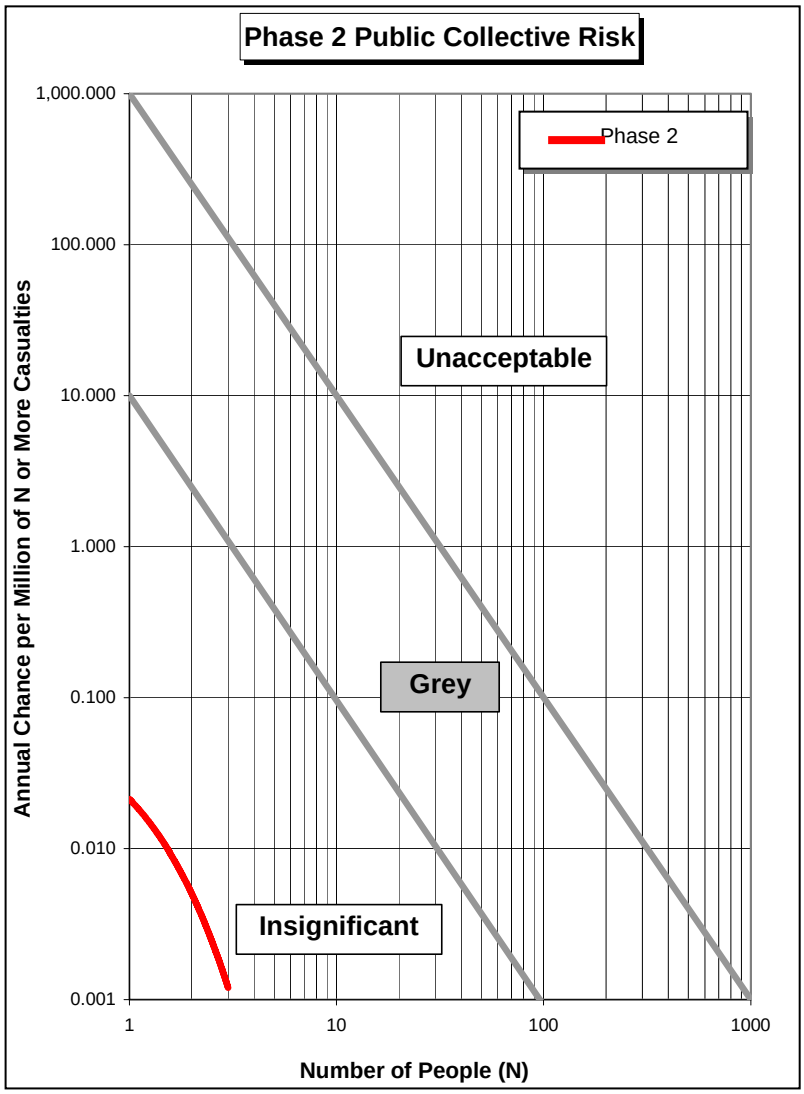


Figure 6.8
Phase 2 Public Collective Risk

6.7 Phase 4 Risk Assessment

6.7.1 Facility Risk Assessment

Again, both the individual and collective risks were assessed for this phase. The initial maximum risk, the individual risk intensity for this phase was calculated by integrating the risks from 30 seconds (again for both holes and ruptures) for each of 3 meteorological classes, and for 4 wind directions, giving a total of 720 risk scenarios. Risk transects resulting from the integration of these scenarios, in each of the 4 wind directions are shown in Figure 6.9. Tables 6.4 and 6.5 give a summary of the IRI and ISR distances, respectively. Again, clearly the risks in the direction downwind (eastwards) of the prevailing westerly winds, are the highest. As before, the risk distances for each of the wind directions are also tabulated, again, from the centroid of the facility which is approximately 100 feet from the nearest fence line, with the nearest residents at roughly 200 feet. As is evident in Table 6.5 and the plot of the isorisk contours shown in Figure 6.10, it can be seen that the resident individual specific risk contours of 1.00E-07 or 1 in 10 million are the highest resident risk values potentially impacting residences near the proposed facility. Finally, once again, a risk spectrum was developed for the process facility, and will be shown in conjunction with the pipeline risk spectrum discussed in the next subsection.

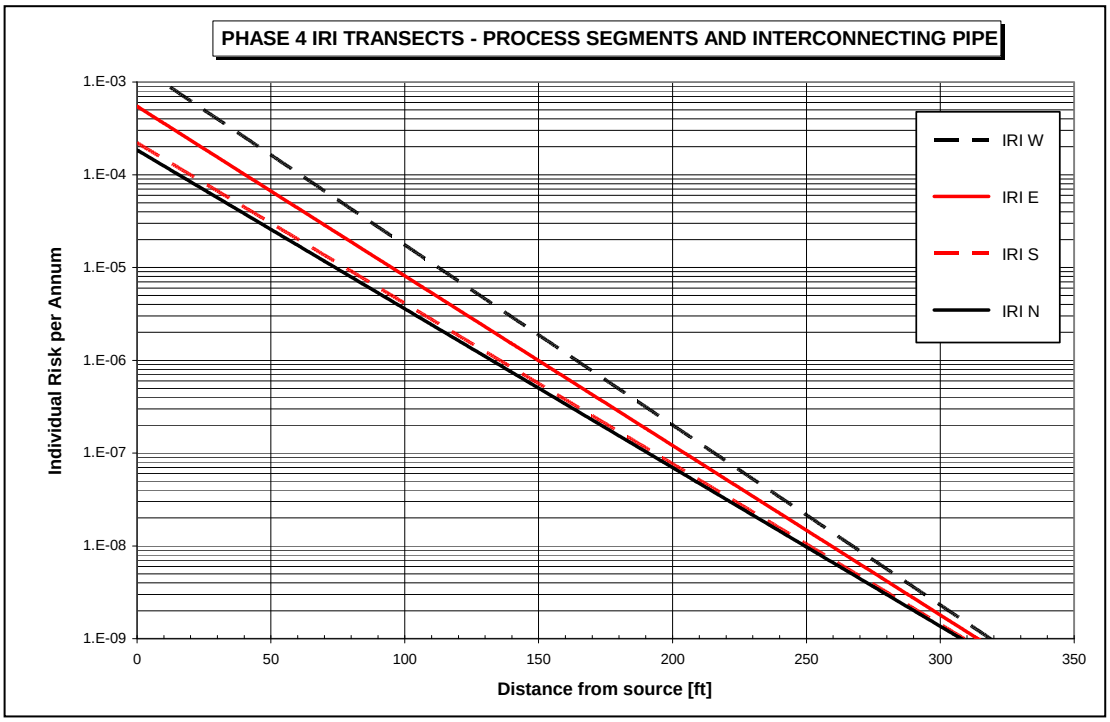


Figure 6.9
Phase 4 IRI Transect

Table 6.4
Phase 4 IRI Risk Distance

Wind Direction	IRI Risk Distance [ft]					
	1.00E-04	1.00E-05	1.00E-06	1.00E-07	1.00E-08	1.00E-09
N	16	74	132	191	249	308
E	40	95	150	205	259	314
S	20	78	135	193	251	309
W	61	113	164	216	267	319

Table 6.5
Phase 4 Resident ISR

Wind Direction	Resident ISR Risk Distance [ft]					
	1.00E-04	1.00E-05	1.00E-06	1.00E-07	1.00E-08	1.00E-09
N	-	19	80	142	204	266
E	-	45	102	160	217	275
S	-	23	84	145	206	267
W	12	66	120	174	228	282

Figure 6.10
Phase 4 Resident Individual Specific Risk Contours

6.7.2 Gas Pipeline Risk Assessment

The natural gas pipeline, an NPS 4 pipeline segment extending approximately ½ mile from the facility along Valley Drive, was carried out by integrating risks calculated utilizing the linear risk algorithm for each of the release size, climate and climate condition scenarios. Thus, a total of 6 scenarios were integrated in assessing the pipeline risk. Figure 6.11 shows the risk transects associated with the gas pipeline. Because of the small diameter and relatively low pressure of the pipeline, one can see that the individual risk intensity barely reaches a maximum of 1 in 10 million, while the individual specific risks to residents reach a maximum of approximately 1 in 100 million at the pipeline, and quickly decay below that outside of 50 feet. Again, the collective risks associated with the gas pipeline, which runs in the proximity of a medium density residential area, were also calculated and registered on the risk spectrum described in the next subsection.

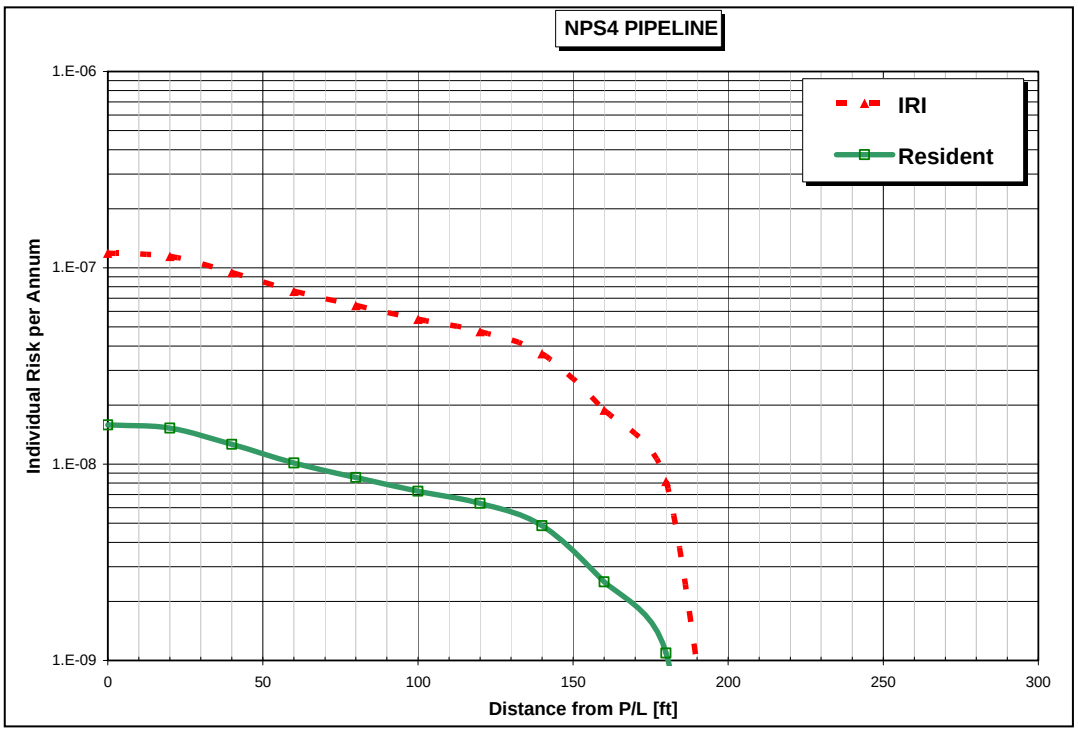


Figure 6.11
Phase 4 Gas Pipeline Risk Transects

6.7.3 Integrated Phase 4 Risk

The collective risks associated with Phase 4 have been integrated into a risk spectrum. This spectrum, shown in Figure 6.12, provides both the collective risk of both the Phase 4 process facility and the natural gas pipeline. Individual risks for each of these would not be integrated as individual risks are location specific, and of course, the pipeline and the facility (except for a very short extent) do not coincide in space. Figure 6.12 shows the collective risk for both the process facility and the pipeline, and their Integrated resultant. All collective risks are in the Insignificant region.

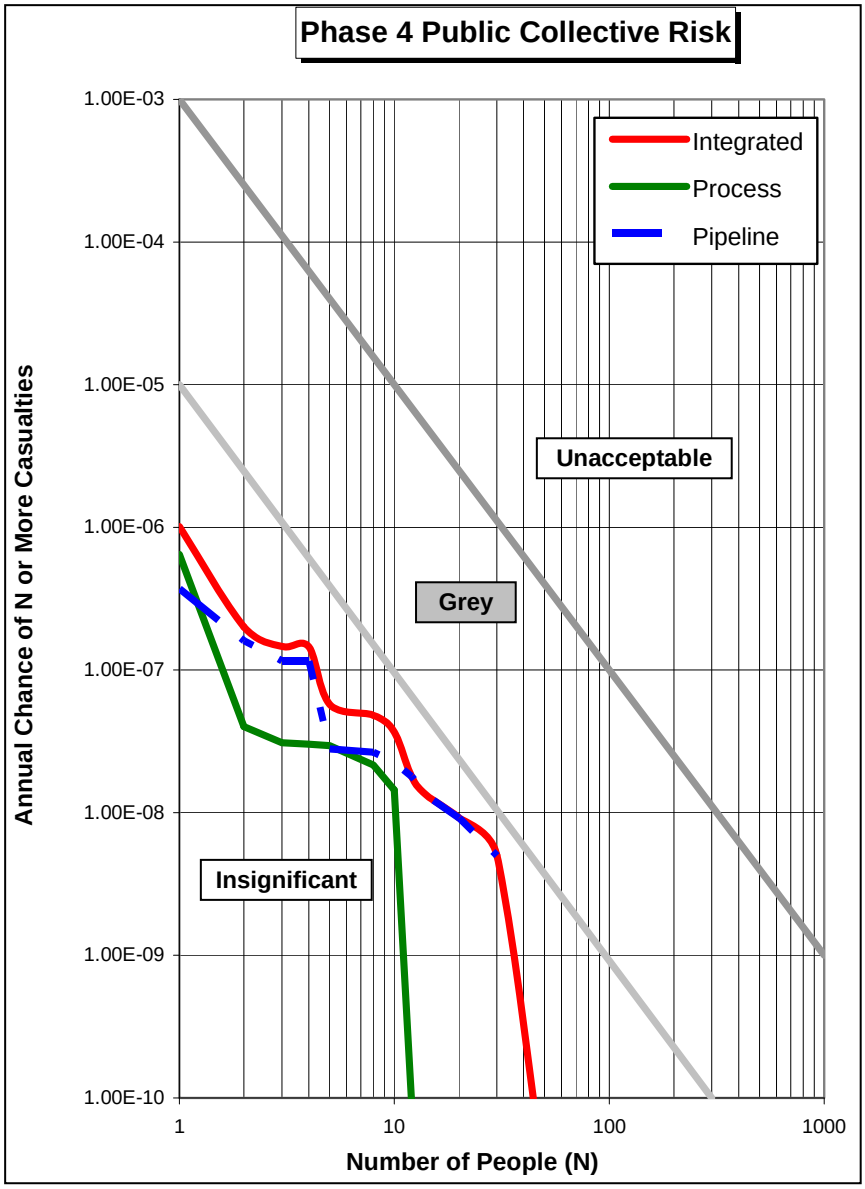


Figure 6.12
Phase 4 Public Collective Risk

CHAPTER 7

ENVIRONMENTAL RISK

7.1 Introduction on Environmental Risks

Environmental spill risks from the Project would only occur as a result of offsite oil transportation. All onsite spills with potential for environmental impact would be contained within the site area. Crude oil offsite risks can only result from spills associated with the Phase 2 crude oil trucking and the Phase 4 oil pipeline, which runs approximately 3.55 miles offsite. Oil spills from neither of these sources pose acute risks to the public; only possible environmental impacts.

7.2 Environmental Risk Matrix Thresholds

The Santa Barbara risk matrix was described in Section 6.3.2, and is repeated here for environmental impacts only as Figure 7.1.

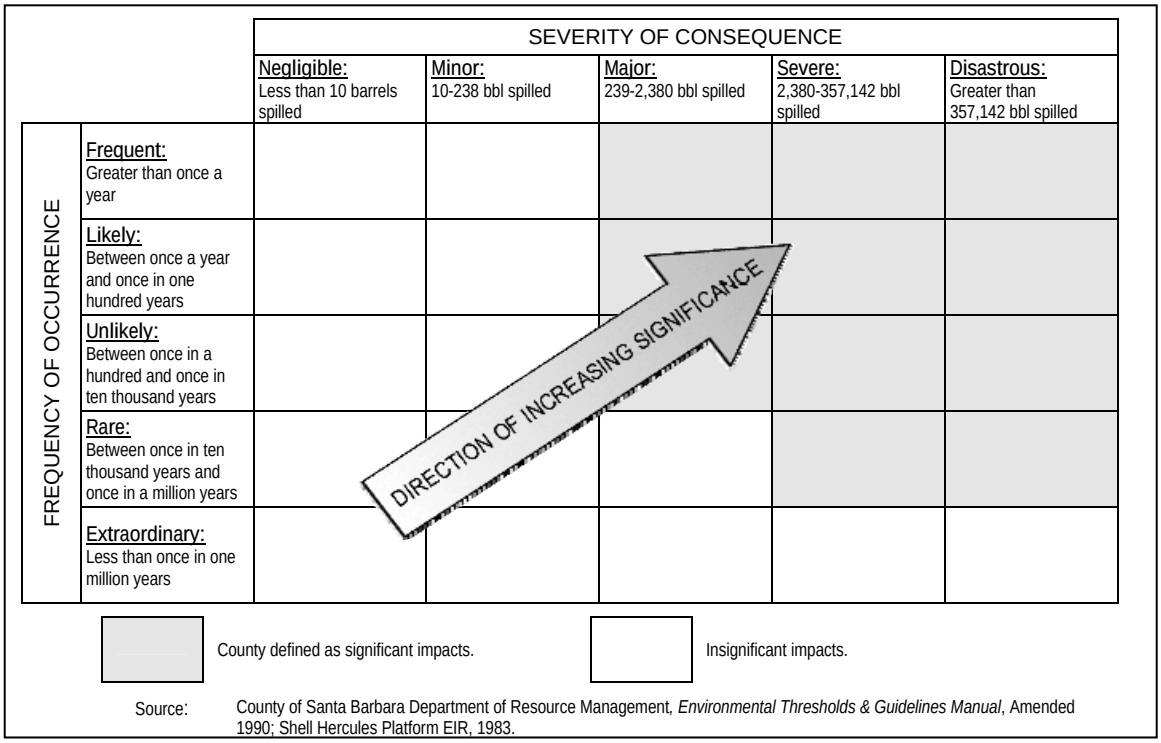


Figure 7.1
Santa Barbara Environmental Risk Matrix

7.3 Crude Oil Trucking

It has been estimated that during Phase 2 [32], crude oil trucks carrying a maximum of 160 barrels (bbl) each would cover a 7.5 mile route approximately 1,400 times, giving a total laden truck total of 10,500 laden-truck miles. This trucking operation is expected to occur within a ten month duration in Phase 2.

The probability and severity (in terms of volume released) of a trucking spill can be quantified as follows:

- Based on an accident rate of 0.4 per million vehicle Dangerous Goods (DG) miles [26], the total annual transit of 10,500 vehicle-miles provides an accident rate of 4.2 in 1,000 per year.
- Assuming 5% of these accidents involve a catastrophic release [27] of a maximum of 160 bbl, this gives an accident catastrophic release rate of 0.21 in 1,000 per year, or roughly 2.1 in 10,000 per year.

This level of risk falls into the *Unlikely* frequency of occurrence, and *Minor* level of environmental risk in the risk matrix, placing it into the Insignificant region, as can be seen in Figure 7.2.

		SEVERITY OF CONSEQUENCE				
		Negligible: Less than 10 barrels spilled	Minor: 10-238 bbl spilled	Major: 239-2,380 bbl spilled	Severe: 2,380-357,142 bbl spilled	Disastrous: Greater than 357,142 bbl spilled
FREQUENCY OF OCCURRENCE	Frequent: Greater than once a year					
	Likely: Between once a year and once in one hundred years					
	Unlikely: Between once in a hundred and once in ten thousand years		Crude Oil Trucking			
	Rare: Between once in ten thousand years and once in a million years					
	Extraordinary: Less than once in one million years					

County defined as significant impacts. Insignificant impacts.

Source: County of Santa Barbara Department of Resource Management, *Environmental Thresholds & Guidelines Manual*, Amended 1990; Shell Hercules Platform EIR, 1983.

Figure 7.2
Risk Matrix with Crude Oil Trucking

It should be noted that the above probability calculation is quite conservative as it does not explicitly consider the numerous trucking safety features which E&B [20] plans to implement. However, even without consideration of the state-of-art safety provisions, the trucking spill risk can be seen to be Insignificant. Quantification of the effects on risk reduction of the key safety provisions is not made, as it would only show that the trucking spill risk is even more Insignificant.

7.4 Crude Oil Pipeline

A crude oil pipeline of approximately 3.55 miles with a diameter of 8 inches (NPS 8) is proposed for transporting produced oil in Phase 4. The probability and severity of a pipeline spill is derived as follows:

- A major release or rupture rate from the Pipeline and Hazardous Materials Safety Administration (PHMSA) rupture statistics is 5.73 per 100,000 mile-years [33].
- With a maximum pipeline length of 3.55 miles, this translates into a rupture frequency of 2 in 10,000 per year.
- Assuming drainage from approximately ½ mile of pipeline in the instance of a rupture, preceded by flow before isolation for 5 minutes maximum, one can estimate a maximum spill of 178 bbl.

Placing $^{2}/_{10,000}$ and 178 bbl on the risk matrix, one can see that the 2 in 10,000 per year falls into the *Unlikely* region, but very close to the *Rare* region, and the spill or 50 bbl falls into the *Minor* consequence area, resulting in a ranking of Insignificance for the pipeline spill potential, as shown in Figure 7.3.

		SEVERITY OF CONSEQUENCE				
		Negligible: Less than 10 barrels spilled	Minor: 10-238 bbl spilled	Major: 239-2,380 bbl spilled	Severe: 2,380-357,142 bbl spilled	Disastrous: Greater than 357,142 bbl spilled
FREQUENCY OF OCCURRENCE	Frequent: Greater than once a year					
	Likely: Between once a year and once in one hundred years					
	Unlikely: Between once in a hundred and once in ten thousand years		Crude Oil Pipeline			
	Rare: Between once in ten thousand years and once in a million years					
	Extraordinary: Less than once in one million years					

County defined as significant impacts. Insignificant impacts.

Source: County of Santa Barbara Department of Resource Management, *Environmental Thresholds & Guidelines Manual*, Amended 1990; Shell Hercules Platform EIR, 1983.

Figure 7.3
Risk Matrix with Crude Oil Pipeline

PHMSA regulated pipelines are generally operated with state of art safety features, including pipeline integrity management, regular magnetic flux leakage (MFL) or pigging in live inspection, corridor signage, protection, and other features discussed in the next chapter. However, the proposed pipeline shall embody a higher level of safety provisions than those of the PHMSA population base, so that the failure rate used here is conservative, as was the case for trucking spill evaluation. Specific pipeline risk mitigation measures adopted by E&B are summarized in Section 8.3.

CHAPTER 8

RISK MITIGATION

8.1 Approaches to Facility Risk Mitigation

Generally, the objective of risk mitigation or safety measures is to reduce risks associated with a system while still permitting it to operate in a productive and cost-effective manner.

Risk mitigation can be addressed on two principal levels; namely, at the source or failure and at the effect or consequence level. That is, we can reduce the frequency and volume of hydrocarbon releases at the source or we can reduce the magnitude of adverse consequences or effects. Examples of failure frequency risk reduction include the use of shear ram Blowout Preventors (BOP's) to facilitate uncontrolled well shut-in; restriction of use and access to facility site to help prevent third party damage; or the use of pipe with greater wall thickness to reduce corrosive and third party impact ruptures. Examples of consequence risk mitigation measures include site selection to minimize public exposure to accidental releases; installation of additional remotely operated valves (ROV) to reduce potential spill volumes; enactment of land use zoning ordinances to restrict development and residence in areas exposed to high consequence potential; and planning and implementation of appropriate emergency response measures to reduce accident effects through timely evacuation.

Both the source and effect levels of safety enhancement can be further classified under the general headings of strategic or tactical. Strategic measures are ones designed to avoid accidents or their effects in advance. Tactical measures are ones designed to minimize the adverse effect of an accident if it does take place. Thus, ROW control, extra engineering and construction measures, and zoning regulations are considered as strategic, while measures such as emergency response, facility segment isolation valves, or automatic shutdown are considered to be tactical measures.

Figure 8.1 summarizes the principal levels and types of risk mitigation measures in block diagram form, under the general categories introduced above.

The general classification of risk mitigation measures given in Figure 8.1 applies to a broad range of industrial facilities. Mitigation measures are broadly classified into initial failure (F) or consequence (C) mitigation measures of a strategic (S) or tactical (T) nature.

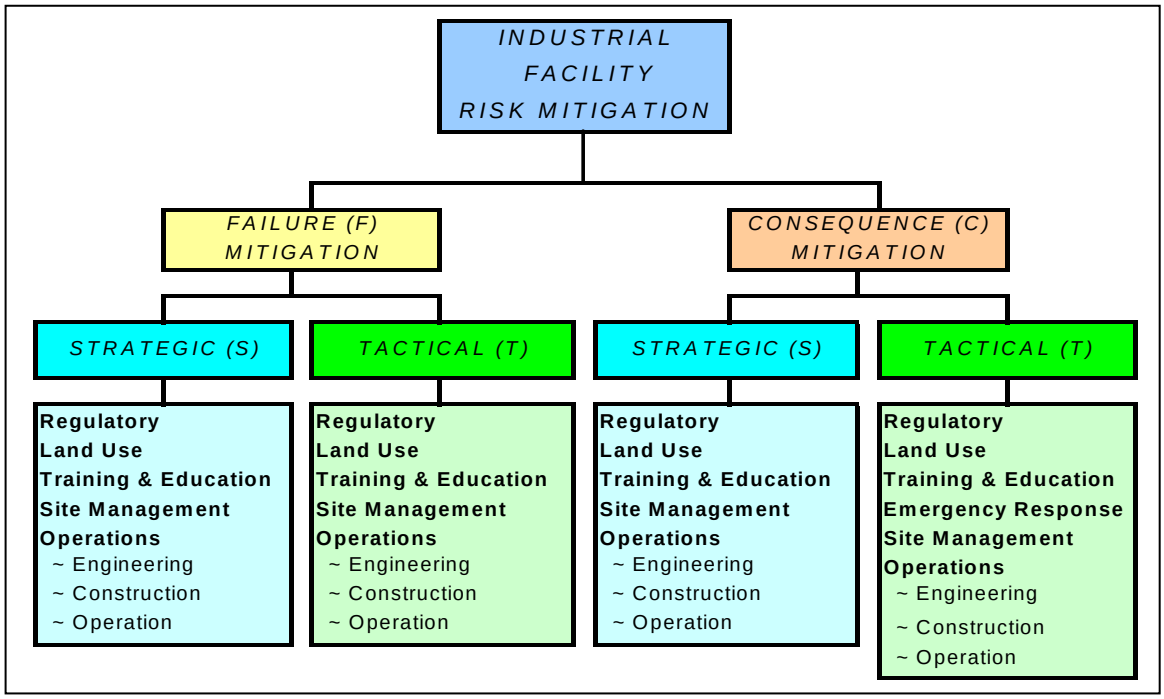


Figure 8.1
Schematic of Risk Mitigation Measures

8.2 Facility Risk Mitigation Measures

8.2.1 Specific Facilities Risk Mitigation Measures

Table 8.1 summarizes specific risk mitigation measures for both failure and consequence risk mitigation, designating the type of measure in accordance with F,C,S,T nomenclature introduced above. Possible mitigative action by an operator or regulator for each measure is given in the right column under "Facility-Specific Details". E&B has confirmed [20] it plans to adopt all the risk mitigation measures included in Table 8.1.

Regulatory measures, pertaining to control of development outside a facility boundary, include emergency response plans for the surrounding area, local agency personnel training, and general public awareness. Land use, again relating to control of development by the local jurisdiction outside the facility boundary includes restrictions of future development in the near vicinity of the facility, buffer zones and setbacks, and control of access to the site vicinity.

The site management program can include much more stringent measures as the plant site is under direct control of the operator. Thus, site security, entry control, night time security personnel and equipment, fencing, posting, and general access control as well as surveillance and monitoring of the site and its surroundings on a regular basis, are included in site management. Immediate rectification of any threats to the facility both due to environmental causes such as subsidence or unanticipated ground water conditions, or third party intervention such as recreational or other usage of areas in close proximity can be easily carried out.

Table 8.1
Industrial Facilities Specific Risk Mitigation Measures

Measure	F/C	S/T	Description	E&B Facility-Specific Details
Regulatory	C	S	Emergency response plan requirements	Emergency Response Plan for facility on display for operator personnel and on file with the Regulator.
	F/C	S	Worker training	All operator personnel will be trained in risk management and facilities operations.
	C	S	Public awareness	Fire safety, public notification, warning and evacuation plan developed as required by Regulator.
Land Use	C	S	Provide protection for offsite development	Extensive design and operational protection for offsite locations.
	C	S	Require protection or buffer zone and setbacks	Perimeter wall and optimal safety provisions to protect public.
	F	S	Control of site access	Perimeter walls all four sides. Site operated 24-hours, access permitted only to operational personnel or approved visitors.
Training	F/C	S/T	Personnel training in operations, emergency response, contingency plans	All operator personnel will be trained in risk management, emergency response procedures, contingency plans and facilities operations.
	C	T	Area public awareness and evacuation training	Fire safety, public notification, warning and evacuation plan required by Regulator. Evacuation training to be determined by third party.
	F/C	T	Use of experienced personnel and thorough screening and training for new personnel	Only experienced and trained operation personnel will be employed at the site.
Site Management	F	S	Site security entry / egress control	Perimeter walls all four sides. Site operated 24-hours, access permitted only to operational personnel or approved visitors.
	F/C	C	Night time security personnel and devices	Site operated 24-hours, operation personnel trained in site security.
	F/C	S	Surroundings surveillance and monitoring	Site operated 24-hours with ongoing monitoring.
Emergency Response	C	T	Emergency response plan / team / facilities	Emergency Response Plan posted and on file with Regulator. Emergency response team consisting of personnel team and Regulator (or equivalent agency) available 24-hours.
	C	T	Detection / alarm systems (gas/fire/overpressure)	Detection alarm systems installed to provide notification to operating personnel of gas release, fire, overpressure and other malfunctions of system.
	C	T	Area public awareness	Fire safety, public notification, warning and evacuation plan publicized.
	C	T	Fire fighting equipment as required	A Fire Protection Plan posted and on file with Regulator delineating the fire protection facilities installed at site.
	C	T	Coordination of local emergency capabilities including police, fire, hospital	Emergency Response Plan posted and on file with Regulator provides procedures for coordination of local emergency capabilities with local fire department.
Operations				
• *Engineering*	C	S	Facilities layout to minimize hazards	Facilities have been designed to minimize hazards and for ease of operations.
	C	S	Site location to avoid exposure	Site location selected to avoid significant risks to public, with isolation from residential areas.
	F/C	T	Emergency Shut Down (ESD) valves to isolate critical sections	Automatic ESD valves to isolate critical sections of process and to minimize hazard.
	C	T	Emergency power and control double backup	Emergency power is not required for shutdown. Facilities will safely shutdown when loss of electrical power occurs.
	C	T	Leak detection and monitoring	Facility site manned 24-hours, production facilities will be inspected on a regular basis throughout the day. Facility provided with a gas and flame detection system.
	C	T	Automatic shutdown	Critical process equipment provided with alarm and automatic shutdown of equipment and in some cases automatic shutdown of facilities.
	F/C	S	State of art engineering	Facilities engineered and designed to latest codes and standards. Facility design reviewed by independent engineering company.
	C	T	Drainage/ venting systems release	Facility is equipped with vent and bleed system. The facility is provided with an emergency vent system for emergency releases.
	C	T	Connect to flare system for overpressure depressurization	All pressure vessels connected to emergency vent system with vent stack to safely permit depressurization of vessels.
	C	T	Overpressure PSV	All tanks and pressure vessels provided with pressure relief valves to protect tanks and pressure vessels from overpressure.
	C	S	HAZOP ongoing procedures	HAZOP study will be initiated at conceptual design and updated to reflect any proposed changes to processing facilities.
	C	T	Design for fire / explosion protection of critical facilities as required	An approved Fire Protection Plan including explosion protection will be developed and updated regularly.
• *Operation*	F/C	S	Safe operating procedure philosophy	A safe operating procedure philosophy will be maintained throughout the life of the project.
	C	T	Alarm systems known to all personnel	All personnel will be thoroughly trained in operations procedures including alarm systems.
	C	T	Emergency response plans and facilities	Emergency response plans and equipment will be in place before startup of facilities.
	F	S	Regular inspection and maintenance	The operational procedures manual includes a documented inspection and maintenance program for a production facilities.
	F	S	Event-driven (e.g., overpressure) inspection and maintenance	The facilities will be inspected and evaluated after any major upset or event.

All aspects of emergency response are important consequence reduction tactical risk mitigation measures for industrial facilities. Thus, emergency response planning, team designation, and facilities and equipment, are essential. More specifically, within a typical process area, fire, gas, and overpressure detection and alarm systems with appropriate levels of redundant backup are important to mitigate the consequences of any possible failures or deviations from normal processes.

Finally, engineering and operational risk mitigation measures constitute strategic mitigation measures for a process facility. Design of the facilities, firstly, at a site located or protected by enclosures to avoid exposure to the public, and secondly, with a general layout to minimize hazards, is essential. Location of potential release sources considering wind direction and flange orientation to avoid accidental release directed at vulnerable locations constitute layout details for strategic mitigation. If layout alone will not satisfy safety requirements, erection of fire walls, explosion barriers, and other protective structures may be more feasible. Within the process network itself, emergency shutdown (ESD) capabilities for critical sections to isolate them and to reduce the volumes of accidental releases, are essential.

All ESD requires either emergency power and backup or is automatic. All principal facility components will be equipped with automatic ESD valves. Leak detection systems, fire detection and automatic suppression, monitoring, and drainage for spills and venting systems for gas releases, all constitute state-of-the-art engineering provisions for safe process operation.

Operating procedures themselves, starting with a risk based operating philosophy, with appropriate personnel training programs, backed by reliable detection and alarm systems are important for a safe facility. Regular inspection and maintenance, provision for unscheduled inspections in case of potentially damaging events, and thorough and meaningful process deviation and incident reporting are essential monitoring and documentation risk management measures.

It should be noted that this listing of facility risk mitigation measures has been confirmed as part of E&B's facility design and operational plan.

8.2.2 Principal Facility Risk Mitigation Measures

Principal risk mitigation measures used in modern facilities are summarized as follows:

- **Layout**
  - Facilities to be installed in an optimal layout minimizing the potential for containment of explosive vapors and permitting ease of personnel entry and egress.
  - Layout to facilitate access and execution of inspection, maintenance, and emergency response activities.

- **Engineering Design**
  - Isolation including Emergency Shutdown (ESD) valves capable of isolating inventory in critical locations such as high pressure gas segments, storage tanks, and well manifolds.
  - Blowdown or venting capability for critical segments which may contain vapors.
  - Closed loop system so that all blowdowns are directed to the flare.
  - Location of redundant gas, fire, overpressure detectors and automatic alarm systems at strategic locations throughout the process areas.
  - Isolation through remotely activated or automatic valves with signal from pressure, hydrocarbon, or fire detectors, level transmitters and pressure transmitters with overpressure alarms.
  - Formal HAZID and HAZOP carried out to identify hazards to guide implementation of risk mitigation measures throughout the design, engineering, and construction phases, commissioning, and operations phases, including change management.
  - State-of-art design for stable operations, recovery from upsets by an experienced operations team with a successful record.
- **Operation**
  - Backup equipment systems installed for critical elements including vapor detection and shutdown.
  - Experienced operators normally on duty working to proven management system in accordance a state-of-art operating plan for all aspects of operations.
  - Extensive screening of all new personnel and supervision of all new personnel with experienced personnel during all critical operations.
  - Fire fighting and emergency response capability assured through regular and unscheduled drills.
  - State of art operating plan including inspection, procedures, maintenance, event-related inspection and maintenance, drills, pressure tests, integrity assessments, and change management.

E&B has also indicated [20] its plan to use all of the above risk mitigation measures.

8.3 Pipeline Risk Mitigation Measures

8.3.1 Pipeline Release Risk Mitigation Measures

Pipeline risk mitigation measures generally applicable to the Project are summarized in this section.

In Table 8.2, the risk mitigation measures have been subdivided into the principal categories identified in Figure 8.1. Risk mitigation measures unique to pipelines are primarily those relating to the right-of-way management and protection, internal inspection, and leak detection, monitoring, and emergency shutdown and isolation facilities.

It should be noted that this listing of pipeline risk mitigation measures has also been confirmed by E&B [20] as part of its engineering and operational plans.

Table 8.2
Pipeline Risk Mitigation Measures

Measure	Description	E&B Pipeline-Specific Details
Regulatory	Design and construction to codes and standards	▪ Pipeline to be designed and constructed in accordance with applicable codes and standards.
	Requirement for Emergency Response Plan	▪ Plan filed with Regulator.
	Accident reporting	▪ Regulator requirement.
Land Use	Design and develop a maximum setback	▪ Regulator guidelines
	Setbacks to avoid RoW third-party damage	▪ Regulator (CSFM) posting, development control, public awareness, and line patrols.
Training and Education	Train operator personnel in natural gas risk mitigation and pipeline operation	▪ All operator personnel will be trained in risk management and pipeline operations.
	Public awareness	▪ Permanent signs with operator's telephone number to be installed along pipeline route. A notification process as required by Regulator will be in place to warn public of any safety requirements. ▪ Periodic public consultations have been held to increase public awareness or project safety.
RoW Management	Review easement agreements	▪ All easement agreements to be in place prior to installation of pipeline.
	Have good access for emergency vehicles	▪ NGP safety personnel have access to all points on the RoW.
	Post signs on RoW	▪ Adequate posting in accordance with regulations.
	Surveillance and monitoring	▪ Pipeline route to be visually inspected on a regular basis.
Emergency Response	Emergency Response Plan	▪ Emergency Response Plan on file with Regulator and municipal jurisdiction.
	Emergency training and drills	▪ Operating personnel to be trained and drilled in emergency procedures and use of the Emergency Response System.
	Public awareness of emergency response by evasion, evacuation, and tight shelter	▪ Emergency Response Plan provides for a formal liaison program, first responder program and emergency planning zone resident program.
Pipeline Operations	Low stress design	▪ Pipeline operating pressures are within code requirements.
▪ Engineering	Appropriate pipeline design	▪ Applicable codes and standards
	Detailed stress analysis and flexibility analysis	▪ Applicable codes and standards
	High quality external coating	▪ Pipe has appropriate external factory field and coating.
	LBV and check valves optimal spacing	▪ To meet or exceed code requirements.
	Automatic alarm and rupture detection	▪ SCADA system installed on pipeline. ▪ High and Low parameter alarms for various operating envelope transgressions are included.
	Greater burial depth	▪ Pipeline depth meets or exceeds code requirements.
	Route selection to avoid exposed population	▪ Regulator and municipalities approved pipeline route.
	Optimal Line Block Valve (LBV) location and spacing	▪ LBV installed as required for class designation.
▪ Construction	Stress-relieve welds	▪ Welds stress-relieved as required by code.
	Weld procedure strict	▪ Pipeline welding to be in accordance with applicable codes and standards.
▪ Operation	Pipeline integrity management program	▪ The pipelines have an "integrity plan" that includes periodic inspection, corrosion modeling, and regular flights. Pipeline installed with SCADA system and pipelines in RoW have high and low pressure alarms. ▪ Operating envelope defined. ▪ Operating envelope transgressions reported and analyzed. ▪ Magnetic Flux Leakage (MLF) technology used. ▪ Risk assessment for internal and external integrity. ▪ Corrosion experts inputs. ▪ Regular inspection and maintenance program. ▪ Monitoring of any repairs as required over a period of 48 hours following completion of the repair. ▪ RoW maintenance.
	Construction inspection follow-up	▪ Following installation of new pipeline, all functions are monitored continually, and personnel patrol the pipeline for an appropriate period following startup to assure timely detection of any installation defects that could affect initial operations.
	Operating personnel training	▪ Comprehensive operating and inspection personnel training is carried out both initially and with periodic upgrades as required. ▪ Third party operator personnel competency certification.
	Emergency measures in place	▪ Implementation of Emergency Response Plan.
	Surveillance	▪ Regular and target of opportunity visual surveillance of critical above-grade facilities.
	Magnetic Flux Leakage (MFL) technology	▪ Inspection frequencies determined by analysis of installation history, operating envelope, past inspection history, and risk assessment. ▪ Pipeline maintenance pigging. ▪ Type of operating envelope determines the need for pipeline pigging.
	RoW posting and monitoring	▪ Permanent signs with operator or first call telephone numbers installed along pipeline route, meeting or exceeding regulatory requirements. ▪ Periodic inspections of all signage are made to assure its integrity.
	Parameter exceedance alarm systems	▪ High and low pressure alarm systems at the control centre exist to alert operator of pressure or other parameter changes in pipeline, prior to LBV closure.
	Emergency Response Team on call	▪ An Emergency Response Team equipped and available 24 hours.
	Line Block Valve (LBV) testing and inspection	▪ Regular testing and inspection programs for the LBVs are carried out including valve maintenance, greasing, and function testing annually.

8.3.2 Principal Pipeline Safety and Risk Mitigation Measures

Table 8.3 summarizes the pipeline safety on risk mitigation measures which E&B has furnished [20], and to which it is committed.

Table 8.3
E&B Pipeline Safety Provisions

Category	Safety Measures
Drug and Alcohol (D&A)	Provides requirements to ensure the pipeline workforce is drug and alcohol free • Written program • Supervisor training to recognize signs of use • Initial testing upon hiring • Random testing throughout employment • Written program and testing audited by PHMSA and CSFM
Operator Qualification (OQ)	Provides requirements to ensure the pipeline workforce is qualified • Written program • All individuals (company and contractors) must be qualified to conduct work on the pipelines • Qualification means successful completion of a knowledge test and job performance evaluation (review by trained evaluator of person actually conducting or simulating the work) • Written program and verification of qualification process audited by PHMSA and CSFM
Design and Construction	Provides requirements for design and construction of all new pipelines • Pipeline to be designed and constructed in accordance with applicable PHMSA/CSFM codes and standards • Cathodic protection systems to prevent corrosion • Coating systems to prevent corrosion • Pipeline designed and constructed to be smart piggable • Pressure test upon completion of construction • Automatic emergency valves for isolation during an emergency • Leak detection systems and SCADA • Over pressure protection • Use of proper pipeline materials
Operations and Maintenance (O&M)	Provides requirements for ongoing required routine operations and maintenance • Public awareness program includes annual education of the public, businesses, excavators, public officials, and emergency responders • Pipeline makers installed and maintained along the right-of-way • Emergency response written program including annual training and drills of company personnel • Annual liaison meeting with emergency responders • Ongoing patrol and inspection of pipeline right-of-way • Annual emergency valve inspections • Annual over pressure protection inspections • Annual cathodic system review and inspections • Annual gas leak surveys with instrument • Pipeline systems are controlled and monitored 24 hours-a-day from a control center • Control room operator specific training and fatigue training • Specific requirements for any repairs conducted • Written program and records verification of O&M process audited by PHMSA and CSFM
Integrity Management Program (IMP)	Provides enhanced protection for pipeline in defined High Consequence Areas (HCAs = Populated and/or environmentally sensitive areas) • Written program • Identification of all High Consequence Areas (HCAs) • Identification of specific threats like internal/external corrosion, third party damage, natural forces like earthquakes, material defects, etc • Ongoing smart pigging program that identifies any anomalies (internal/external corrosion, dents, weld defects, pipe material defects) • Remediation plan to schedule and repair anomalies discovered • Additional preventive and mitigative measures like increased frequency of surveillance and inspections, additional safeguards, etc • Performance measures to identify trends • Risk analysis and ongoing continuous improvement • Written program and records verification of integrity process audited by PHMSA and CSFM

8.4 Trucking Risk Mitigation Measures

Trucking safety and risk mitigation measures attested to by E&B [20] are as follows:

- Pre-employment driver screening program
- Random drug and alcohol testing of drivers
- Fully certified drivers
- Notification of traffic violations
- Regular and event related vehicle inspections and maintenance
- Onboard safety systems
    - Onboard brake stroke monitoring systems
    - Collision mitigation and threat warning systems
    - Lane departure warning systems
    - Rear and side collision detection and warning systems
    - Vehicle stability systems
    - Tire pressure monitoring systems
    - Wireless mobile communication
- GPS tracking and data monitoring
- Auditing

CHAPTER 9

INPUTS AND CONCLUSIONS

9.1 Principal Inputs

Inputs characterizing Phases 2 and 4 and associated transportation operations were provided by E&B and others, and Bercha relied on these inputs. E&B and others also provided the permanent population distributions.

Certain significant conservative assumptions and approximations were made, resulting in the tendency to overestimate the risks associated with the project. The principal ones among these may be summarized as follows:

- All gas releases were assumed to continue to blowdown until atmospheric pressure is reached within the isolated segment.
- Modeling of ground level releases rather than elevated releases as a basis for flash fire damage assessment was carried out.
- All pressurized releases were assumed to occur in the horizontal direction.
- A heater treater was assumed in place of microturbines to provide a worst case scenario.

The failure frequencies used were based on current western industrial case averages. The frequency used did not explicitly quantify the additional safety features [20] planned for the Project. Thus the failure frequencies used for facility components and pipelines are conservative.

Certain simplifying assumptions to facilitate the work were made, which resulted in approximations of the risks. It is believed that these approximations did not significantly impact the resultant risks, but these assumptions are nevertheless summarized, as follows:

- Topography was not explicitly considered in consequence modeling.
- Population distributions provided by the proponent were assumed constant over the 35 year project life.
- Wake effect on gas dispersion of the perimeter wall and its interaction with explosion overpressures were not modeled explicitly.

Certain other simplifying assumptions and approximations were made during the conduct of the work in order to make its completion practicable while still providing meaningful results. These simplifying assumptions and approximations may have the effect of either overestimating or underestimating the risk, but to a negligible degree within the context of the present work. Such simplifying assumptions and approximations may be summarized as follows:

- LAX weather was considered representative of the Hermosa Beach site location due to its proximity.
- Subdivision of release sizes into holes and ruptures for the facility, and into holes and full bore ruptures for the gas pipeline was considered representative of all significant release sizes with offsite consequence potential.

9.2 Conclusions

Both individual and collective risks were evaluated. Acceptability of individual specific risks is determined from the 1 in 1 million per year criterion; at or above 1 in 1 million the risk is deemed Significant; below, it is deemed Insignificant. Figure 9.1 shows the resident individual specific risk contours for Phase 2. Collective risks were measured against the Santa Barbara Risk Spectrum thresholds, shown for Phase 2 in Figure 9.2. Figure 9.3 shows the resident individual specific risk contours for Phase 4; while Figure 9.4 shows the associated Phase 4 risk spectrum.

The following can be concluded from the risk results:

- Individual specific risks for Phase 2 (Figure 9.1) do not exceed 1 in 1 million (10^{-6}) offsite; hence Phase 2 ISR are Insignificant.
- Individual specific risks (ISR) and collective risks (Figure 9.2) for Phase 2 are in the Insignificant region.
- Individual specific risks for Phase 4 (Figure 9.3) do not exceed 1 in 1 million (10^{-6}) offsite; hence Phase 4 ISR are also Insignificant.
- Collective risks for Phase 4, for both the facility and the gas pipeline and their integrated risk, are entirely in the Insignificant region as shown in Figure 9.4.

Environmental risks for the transportation of oil by trucks in Phase 2 and by pipeline in Phase 4 were also assessed and found to be in the Insignificant region using the Santa Barbara Environmental Risk Matrix.

The summary results include annual individual and collective risks, as well as cumulated risks over the project life and the offsite environmental risks for each phase. Table 9.1 summarizes the salient results of the risk, including risk acceptability according to the individual and collective risk thresholds adopted for the project.

In summary, it can be concluded that all risks to the public and environment are acceptable for both phases, as they are in the Insignificant risk region.

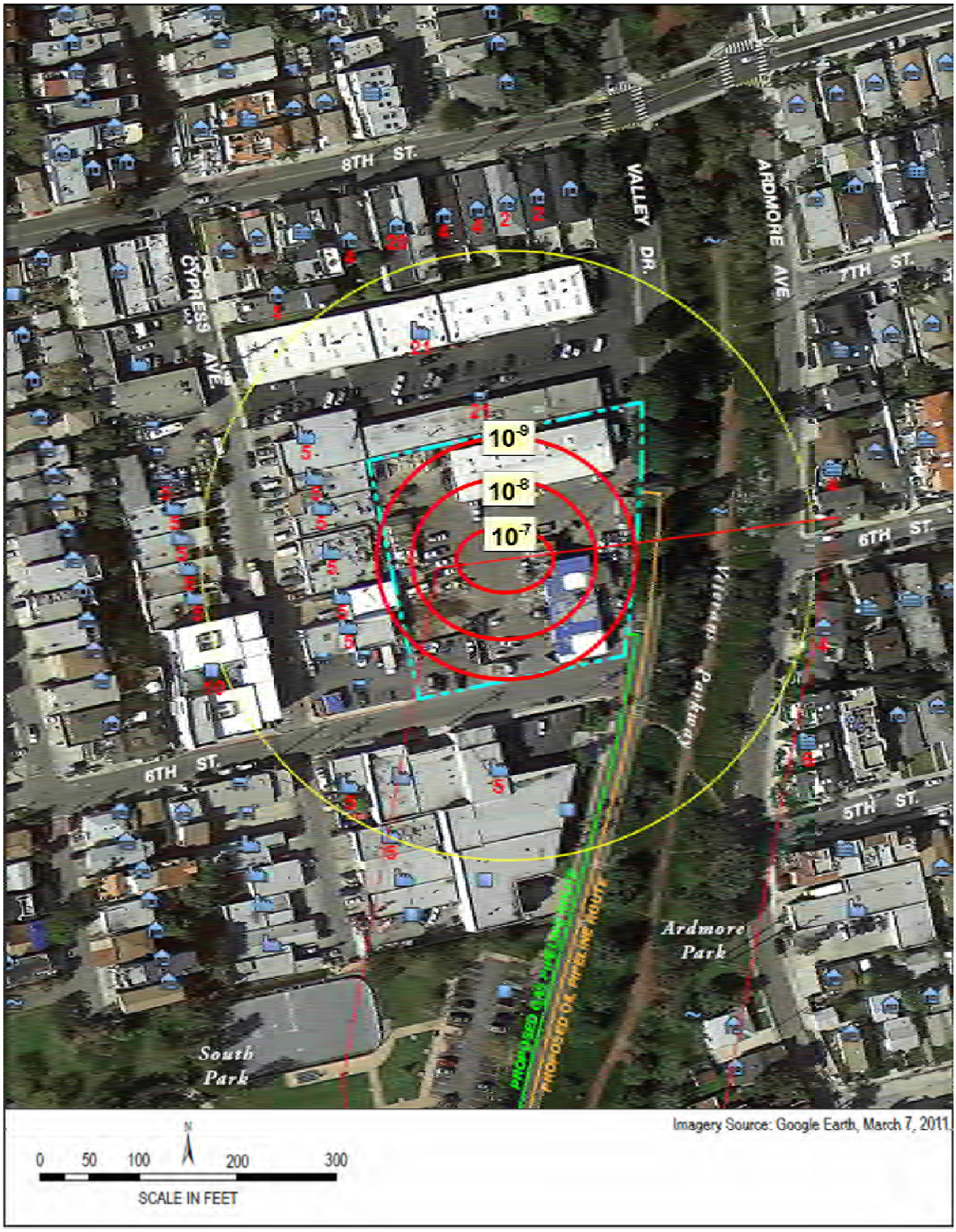


Figure 9.1
Phase 2 Resident Individual Specific Risk Contours

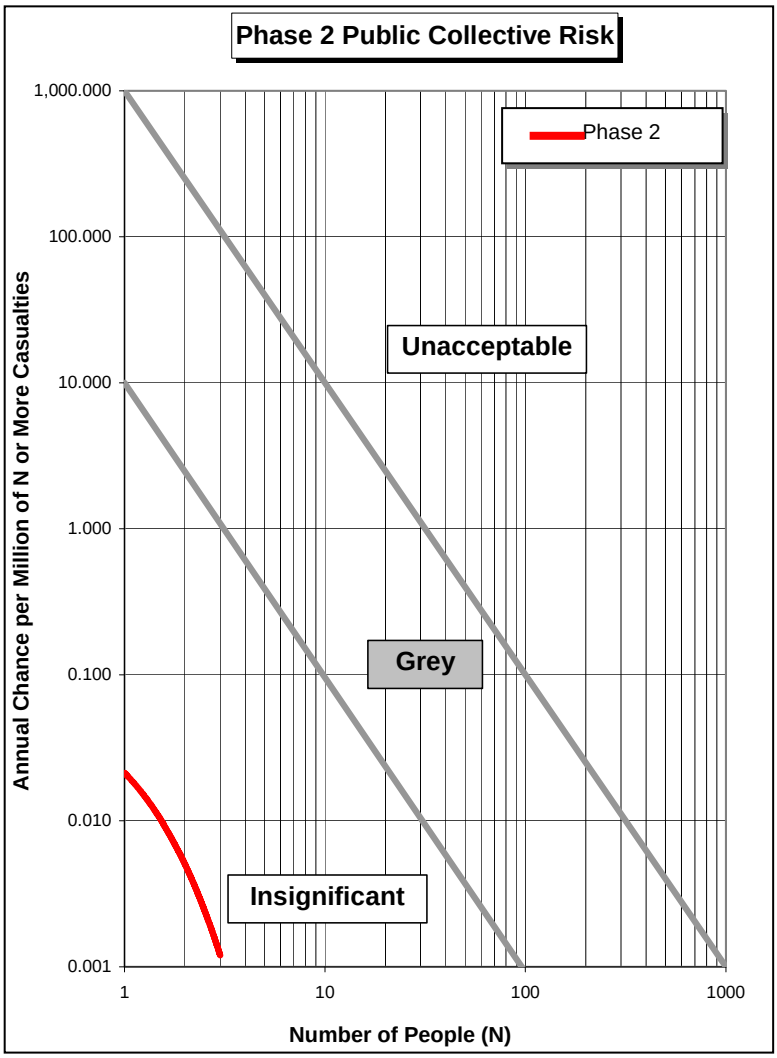


Figure 9.2
Phase 2 Public Collective Risk

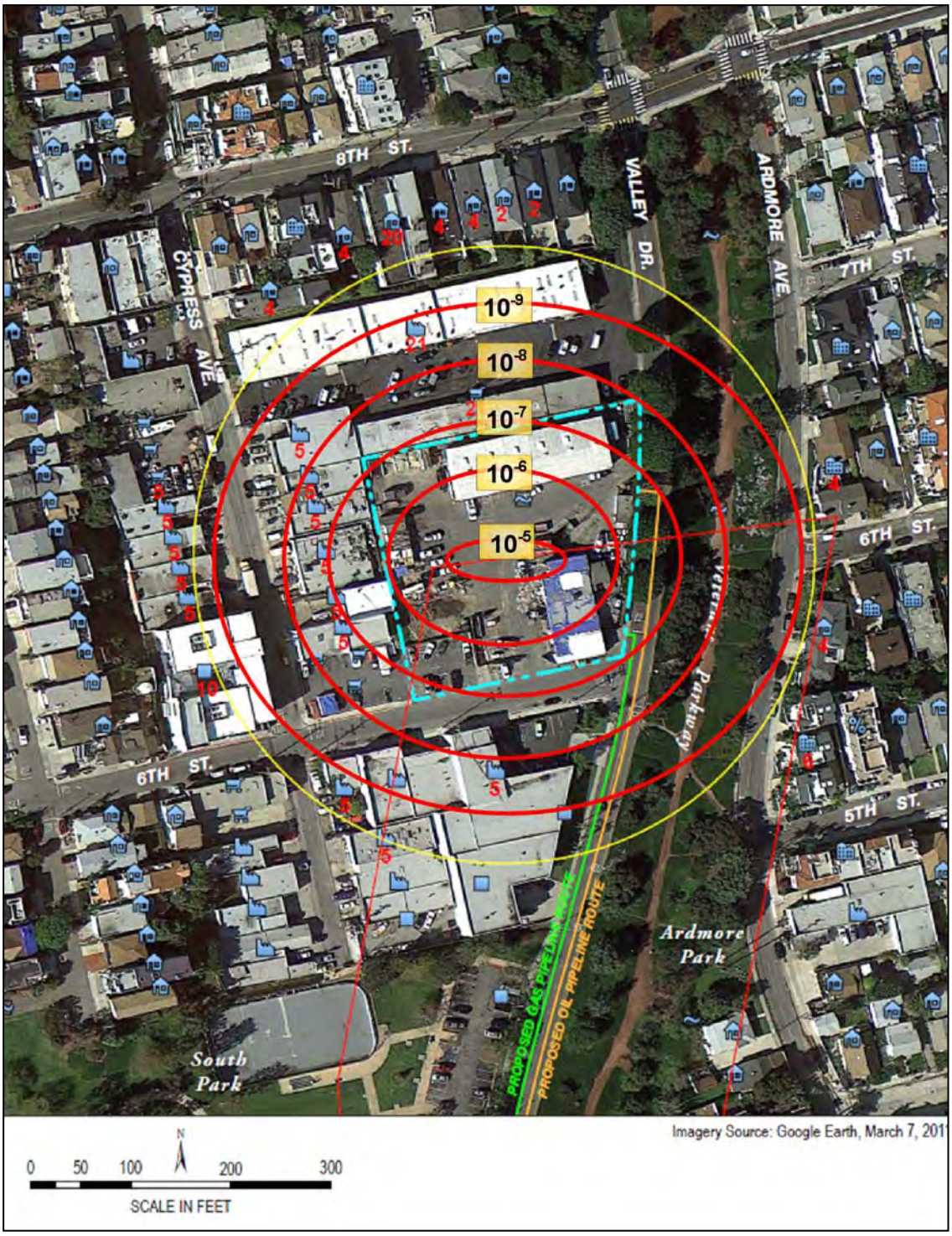


Figure 9.3
Phase 4 Resident Individual Specific Risk Contours

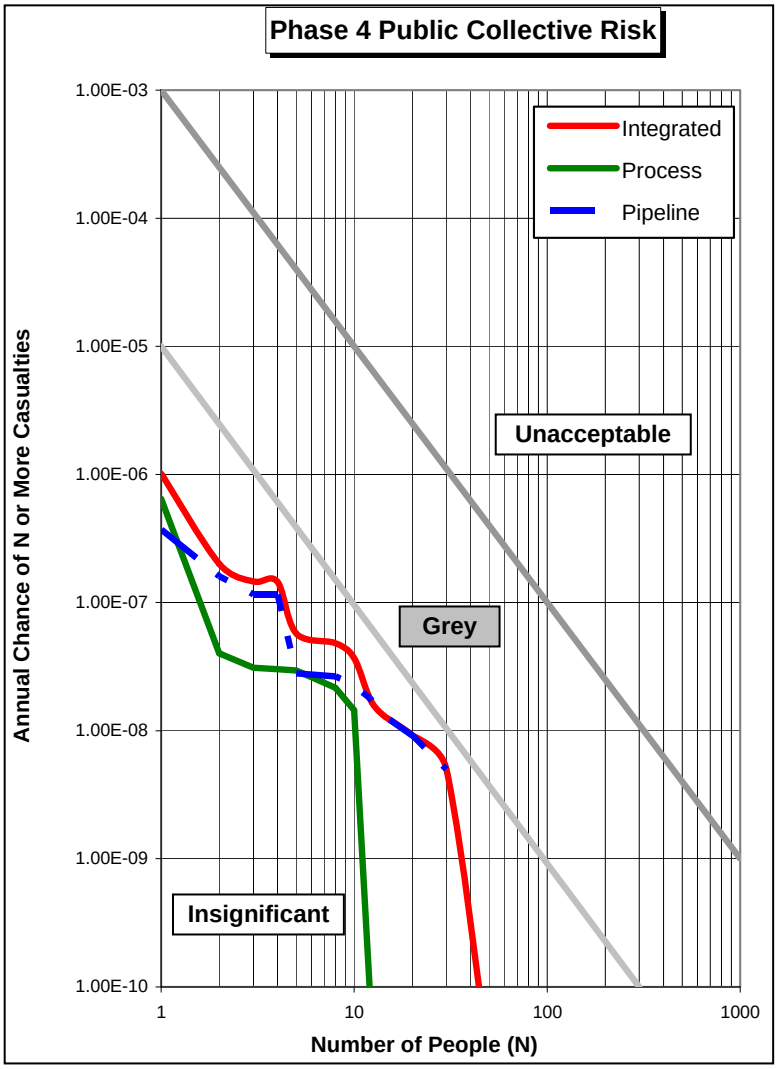


Figure 9.4
Phase 4 Public Collective Risk

Table 9.1
Summary of Hermosa Beach Oil Development Project Risks

PHASE	RISK TO:	TYPE OF RISK	MAXIMUM VALUE (in 1 million)	ACCEPTABILITY	KEY DESIGN FEATURES INCLUDED
2	Public	Maximum offsite resident annual individual specific risk	0.001	Insignificant	• Industry standard measures • Automatic isolation valves • Perimeter wall
		Annual collective risk of 1 or more fatalities	0.01	Insignificant	
		Annual collective risk of 10 or more fatalities	0.0	Insignificant	
	Environment	Trucking environmental annual risk of maximum 160 bbl spill	210	Insignificant	• State-of-art trucking
4	Public	Maximum offsite resident annual individual specific risk	0.01	Insignificant	• Industry standard measures • Automatic isolation valves • Perimeter wall
		Annual collective risk of 1 or more fatalities	1.0	Insignificant	
		Annual collective risk of 10 or more fatalities	0.06	Insignificant	
		Cumulative 35 year resident individual specific risk	0.06	Insignificant	
	Environment	Oil pipeline annual environmental risk of maximum 178 bbl spill	200	Insignificant	• State-of-art pipeline

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