Appendix 4.
System Safety and Risk of Upset

Ap.4.1 Setting

Unintentional releases of natural gas from any of the project components could pose risks to human health and safety. For example, natural gas could be released from a rupture in one of the pipe segments. If the natural gas was to reach a combustible mixture and an ignition source was present, a fire and/or explosion could occur, resulting in possible injuries and/or deaths.

Natural gas is comprised primarily of methane. It is colorless, odorless, and tasteless. Methane is not toxic, but is classified as a simple asphyxiate, possessing a slight inhalation hazard. If breathed in high concentration, oxygen deficiency can result in serious injury or death.

Methane has an ignition temperature of 1,000°F and is flammable at concentrations between 5.0% and 15% in air. Unconfined mixtures of methane in air are not explosive. However, a flammable concentration within an enclosed space in the presence of an ignition source can explode. Methane is buoyant at atmospheric temperatures and disperses rapidly in air.

In this appendix, we will evaluate the fire radiation and explosion overpressure hazards posed by the following project components:

- 16-inch-diameter, 100 MMSCFD (maximum), 25-50 MMSCFD (typical), 1,480 psig (maximum), 600 to 900 psig (typical), 5.9-mile, natural gas transmission pipeline (including meter/regulator station),
- Compressor station (7,200 combined HP),
- 12-inch-diameter, 100 MMSCFD (maximum), 25-50 MMSCFD (typical), 1,480 psig (maximum), 1.1-mile, natural gas flow pipeline, and
- up to 10 new injection/withdrawal wells.

In addition to these permanent facilities, the following temporary facilities could pose risks to human health and safety:

- 4-inch-diameter, 10 MMSCFD, 600 to 900 psig (typical), 1.35-mile natural gas pipeline (including meter station), and a
- Temporary compressor (1,000 HP maximum).

Regulatory Setting – Applicable Laws, Ordinances, Regulations and Standards (LORS)

This section describes the operational safety and risk of accidents aspects of the applicable laws, ordinances, regulations, and standards (LORS) for the subject facilities.

Federal Regulations

The United States Department of Transportation (USDOT) provides oversight for the country's natural gas pipeline transportation. Their responsibilities are promulgated under Title 49, United States Code

(USC) Chapter 601. The Pipeline and Hazardous Materials Safety Administration (PHMSA), Office of Pipeline Safety (OPS), administers the national regulatory program to ensure the safe transportation of gas and other hazardous materials by pipeline.

Two statutes provide the framework for the Federal pipeline safety program. The Natural Gas Pipeline Safety Act of 1968 as amended (NGPSA) authorizes the USDOT to regulate pipeline transportation of natural (flammable, toxic, or corrosive) gas and other gases as well as the transportation and storage of liquefied natural gas (LNG). Similarly, the Hazardous Liquid Pipeline Safety Act of 1979 as amended (HLPSA) authorizes the USDOT to regulate pipeline transportation of hazardous liquids (crude oil, petroleum products, anhydrous ammonia, and carbon dioxide). Both of these Acts have been recodified as 49 USC Chapter 601.

The OPS shares portions of this responsibility with state agency partners and others at the federal, state, and local level. The State of California is certified under 49 USC Subtitle VIII, Chapter 601, §60105. The State has the authority to regulate intrastate natural and other gas pipeline facilities. The Public Utilities Commission is the agency authorized to oversee intrastate gas pipeline facilities, similar to those proposed by the applicant. (The California State Fire Marshal has jurisdiction for hazardous liquid pipelines.)

The federal pipeline regulations are published in Title 49 of the Code of Federal Regulations (CFR), Parts 190 through 199. 49 CFR 192 specifically addresses natural and other gas pipelines. Many of these pipeline regulations are written as performance standards. These regulations set the level of safety to be attained and allow the pipeline operator to use various technologies to achieve the desired result.

The proposed 16-inch-diameter transmission pipeline, 12-inch-diameter flow line, 4-inch-diameter temporary pipeline, meter/regulator station, and compressor station would all be designed, constructed, operated, and maintained in accordance with 49 CFR 192. Since these are intrastate facilities, the Public Utilities Commission would have the responsibility for enforcing the federal and state requirements. 49 CFR 192 is comprised of fifteen (15) subparts, which are summarized below:

- **Subpart A, General** – This subpart provides definitions, a description of the class locations used within the regulations, documents incorporated into the regulation by reference, conversion of service requirements, and other items of a general nature.
- **Subpart B, Materials** – This subpart provides the requirements for the selection and qualification of pipe and other pipeline components. Generally, it covers the manufacture, marking, and transportation of steel, plastic, and copper pipe used in gas pipelines and distribution systems.
- **Subpart C, Pipe Design** – This subpart covers the design (primarily minimum wall thickness determination) for steel, plastic, and copper pipe.
- **Subpart D, Design of Pipeline Components** – This subpart provides the minimum requirements for the design and qualification of various components (e.g. valves, flanges, fittings, passage of internal inspection devices, taps, fabricated components, branch connections, extruded outlets, supports and anchors, compressor stations, vaults, overpressure protection, pressure regulators and relief devices, instrumentation and controls, etc.
- **Subpart E, Welding of Steel Pipelines** – This subpart provides the minimum requirements for welding procedures, welder qualification, inspection and repair/replacement of welds in steel pipeline systems.

- **Subpart F, Joining of Materials Other Than By Welding** – This subpart covers the requirements for joining, personnel and procedure qualification, and inspection of cast iron, ductile iron, copper, and plastic pipe joints.
- **Subpart G, General Construction Requirements for Transmission Lines and Mains** – This subpart provides the minimum construction requirements, including, but not limited to: inspection of materials, pipe repairs, bends and elbows, protection from hazards, installation in the ditch, installation in casings, underground clearances from other substructures, and minimum depth of cover.
- **Subpart H, Customer Meters, Service Regulators and Service Lines** – This subpart prescribes the minimum requirements for these components.
- **Subpart I, Requirements for Corrosion Control** – This subpart provides the minimum requirements for cathodic protection systems, required inspections and monitoring, remedial measures, and records maintenance.
- **Subpart J, Testing Requirements** – This subpart prescribes the minimum leak and strength test requirements.
- **Subpart K, Uprating** – This subpart provides the minimum requirements for increasing the maximum allowable operating pressure.
- **Subpart L, Operations** – This subpart prescribes the minimum requirements for pipeline operation, including: procedure manuals, change in class locations, damage prevention programs, emergency plans, public awareness programs, failure investigations, maximum allowable operating pressures, odorization, tapping, and purging.
- **Subpart M, Maintenance** – This subpart prescribes the minimum requirements for pipeline maintenance, including: line patrols, leakage surveys, line markers, record keeping, repair procedures and testing, compressor station pressure relief device inspection and testing, compressor station storage of combustible materials, compressor station gas detection, inspection and testing of pressure limiting and regulating devices, valve maintenance, prevention of ignition, etc.
- **Subpart N, Qualification of Pipeline Personnel** – This subpart prescribes the minimum requirements for operator qualification of individuals performing covered tasks on a pipeline facility.
- **Subpart O, Pipeline Integrity Management** – This subpart was promulgated on December 15, 2003. It requires operators to implement pipeline integrity management programs on the gas pipeline systems.

In general, the requirements of the federal regulations become more stringent as the human population density increases. To this end, 49 CFR 192 defines area classifications, based on population density in the vicinity of the pipeline and specifies more rigorous safety requirements for more heavily populated areas. The class location is an area that extends 220 yards on either side of the centerline of any continuous 1-mile length of pipeline. The four area classifications are defined as follows:

- **Class 1.** Location with 10 or fewer buildings intended for human occupancy.
- **Class 2.** Location with more than 10 but less than 46 buildings intended for human occupancy.
- **Class 3.** Location with 46 or more buildings intended for human occupancy or where the pipeline lies within 100 yards of a building, or small well-defined outside area pipeline any occupied by 20 or more people on at least 5 days a week for 10 weeks in any 12-month.
- **Class 4.** Location where buildings with four or more stories aboveground are prevalent.

Pipeline facilities located within class locations representing more populated areas are required to have a more conservative design. For example, pipelines constructed on land in Class 1 locations must be installed with a minimum depth of cover of 30 inches in normal soil and 18 inches in consolidated rock. Class 2, 3, and 4 locations, as well as drainage ditches of public roads and railroad crossings, require a minimum cover of 36 inches in normal soil and 24 inches in consolidated rock. All pipelines installed in navigable rivers, streams, and harbors must have a minimum cover of 48 inches in soil or 24 inches in consolidated rock.

Class locations also specify the maximum distance to a sectionalizing block valve (e.g., 10.0 miles in Class 1, 7.5 miles in Class 2, 4.0 miles in Class 3, and 2.5 miles in Class 4 locations). Pipe wall thickness and pipeline design pressures, hydrostatic test pressures, maximum allowable operating pressure, inspection and testing of welds, and frequency of pipeline patrols and leak surveys must also conform to higher standards in more populated areas.

The proposed pipeline facilities would be constructed within a Class 1 location. Although an increase in population density adjacent to the right-of-way is not anticipated (see Land Use), the applicant would be required to reduce the MAOP or replace the segment with pipe of sufficient grade and wall thickness to comply with 49 CFR 192 for the new class location if the population density should increase significantly.

Pipeline Integrity Management

49 CFR 192 Subpart O, Pipeline Integrity Management grew out of a series of pipeline incidents with severe consequences. This Subpart requires operators of gas pipeline systems in High Consequence Areas (HCA's) to significantly increase their minimum required maintenance and inspection efforts. For example, all lines located within HCA's must be analyzed by conducting a baseline risk assessment. In general, the integrity of the lines must also be evaluated using an internal inspection device or a direct assessment, as prescribed in the regulation. Two incidents in particular, raised public concern regarding pipeline safety and necessitated these relatively new requirements.

Bellingham, Washington, June 10, 1999

According to the National Transportation Safety Board (NTSB) accident report, "about 3:28 p.m., Pacific daylight time, on June 10, 1999, a 16-inch-diameter steel pipeline owned by Olympic Pipe Line Company ruptured and released about 237,000 gallons of gasoline into a creek that flowed through Whatcom Falls Park in Bellingham, Washington. About 1½ hours after the rupture, the gasoline ignited and burned approximately 1½ miles along the creek. Two 10-year-old boys and an 18-year-old man died as a result of the accident. Eight additional injuries were documented. A single-family residence and the city of Bellingham's water treatment plant were severely damaged. As of January 2002, Olympic estimated total property damages of at least $45 million.

The major safety issues identified during this investigation are excavations performed by IMCO General Construction, Inc., in the vicinity of Olympic's pipeline during a major construction project and the adequacy of Olympic Pipe Line Company's inspections thereof; the adequacy of Olympic Pipe Line Company's interpretation of the results of in-line inspections of its pipeline and its evaluation of all pipeline data available to it to effectively manage system integrity; the adequacy of Olympic Pipe Line Company's management of the construction and commissioning of the Bayview products terminal; the performance and security of Olympic Pipe Line Company's supervisory control and data acquisition system; and the adequacy of Federal regulations regarding the testing of relief valves used in the protection of pipeline systems."

Carlsbad, New Mexico, August 19, 2000

Per the NTSB accident report, "At 5:26 a.m., mountain daylight time, on Saturday, August 19, 2000, a 30-inch-diameter natural gas transmission pipeline operated by El Paso Natural Gas Company ruptured adjacent to the Pecos River near Carlsbad, New Mexico. The released gas ignited and burned for 55 minutes. Twelve persons who were camping under a concrete-decked steel bridge that supported the pipeline across the river were killed and their three vehicles destroyed. Two nearby steel suspension bridges for gas pipelines crossing the river were extensively damaged. According to El Paso Natural Gas Company, property and other damages or losses totaled $998,296.

The major safety issues identified in this investigation are the design and construction of the pipeline, the adequacy of El Paso Natural Gas Company's internal corrosion control program, the adequacy of federal safety regulations for natural gas pipelines, and the adequacy of federal oversight of the pipeline operator."

Pipeline Integrity Management Regulations

As noted earlier, 49 CFR 192, Subpart O, Pipeline Integrity Management, is relatively new and was developed in response to the to major pipeline incidents discussed earlier. In 2002, Congress passed an act to strengthen the pipeline safety laws. The Pipeline Safety Improvement Act of 2002 (HR 3609) was passed by Congress on November 15, 2002, and signed into law by the President in December 2002. As of December 17, 2004, gas transmission operators of pipelines in high consequence areas (HCA's) were required to develop and follow a written integrity management program that contained all the elements prescribed in 49 CFR 192.911 and addressed the risks on each covered transmission pipeline segment.

The USDOT (68 Federal Register 69778, 69 Federal Register 18228, and 69 Federal Register 29903) defines HCA's as they relate to the different class zones, potential impact circles, or areas containing an identified site as defined in 49 CFR 192.903. The OPS published a series of rules from August 6, 2002 to May 26, 2004 (69 Federal Register 69817 and 29904), that define HCA's where a gas pipeline accident could do considerable harm to people and their property. This definition satisfies, in part, the Congressional mandate in 49 USC 60109 for the OPS to prescribe standards that establish criteria for identifying each gas pipeline facility in a high-density population area.

The HCA's may be defined in one of two ways. (Both methods are prescribed by 49 CFR 192.903.) The first includes:

- current Class 3 and 4 locations;
- any area in Class 1 or 2 locations where the potential impact radius is greater than 660 feet (200 meters) and the area within a potential impact circle contains 20 or more buildings intended for human occupancy; or
- any area in Class 1 or 2 locations where the potential impact circle includes an "identified site."
- In the second method, an HCA includes any area within a potential impact circle that contains:
- 20 or more buildings intended for human occupancy; or
- an "identified site."

"Identified sites" include areas such as beaches, playgrounds, recreational facilities, campgrounds, outdoor theaters, stadiums, recreational areas, religious facilities, and other areas where high concentrations of the public may gather periodically as defined by 49 CFR 192.903.

The "potential impact radius" is calculated as the product of 0.69 and the square root of the maximum allowable operating pressure of the pipeline (in psig), multiplied by the pipeline diameter (in inches) squared. ($R = 0.69 \times (MAOP \times d^2)^{0.5}$)

The potential impact circle is a circle with a radius equal to the potential impact radius.

Once a pipeline operator has determined the HCA's on its pipeline(s), it must apply the elements of its integrity management program to those segments of the pipeline within HCA's. The pipeline integrity management rule for HCA's requires inspection of the entire pipeline within HCA's every 7 years.

As noted earlier, the proposed pipeline facilities are located within a Class 1 area. As a result, they will not be required to be included in a Pipeline Integrity Management Plan.

State Regulations

As noted earlier, these intrastate pipeline facilities are under the jurisdiction of the CPUC, as a result of their certification by the OPS. The retrieval/storage wells fall under the jurisdiction of the California Division of Oil and Gas Resources.

Potential Impacts to Humans

The physiological effect of fire on humans depends on the rate at which heat is transferred from the fire to the person, and the time the person is exposed to the fire. Skin that is in contact with flames can be seriously injured, even if the duration of the exposure is just a few seconds. Thus, a person wearing normal clothing is likely to receive serious burns to unprotected areas of the skin when directly exposed to the flames from a flash fire (vapor cloud fire).

Humans in the vicinity of a fire, but not in contact with the flames, would receive heat from the fire in the form of thermal radiation. Radiant heat flux decreases with increasing distance from a fire. So those close to the fire would receive thermal radiation at a higher rate than those farther away. The ability of a fire to cause skin burns due to radiant heating depends on the radiant heat flux to which the skin is exposed and the duration of the exposure. As a result, short-term exposure to high radiant heat flux levels can be injurious. But if an individual is far enough from the fire, the radiant heat flux would be lower, likely incapable of causing injury, regardless of the duration of the exposure.

An incident heat flux level of 1,600 Btu/ft^2-hr is considered hazardous for people located outdoors and unprotected. Generally, humans located beyond this heat flux level would not be at risk of injury from thermal radiation resulting from a fire.

Table Ap.4.1-1. Worst-Case Release Radiant Heat Exposure Data

Radiant Heat Value	Effects on Human Skin
3,500 Btu/hour-square foot (11.0 kW/m^2)	Second degree skin burns after ten seconds of exposure. 15% Probability of Fatality (Note 1)
1,600 Btu/hour-square foot (5.0 kW/m^2)	Second degree skin burns after thirty seconds of exposure
440 Btu/hour-square foot (1.4 kW/m^2)	Prolonged skin exposure causes no detrimental effect

Notes:
1. The 15% probability of fatality figure assumes that an exposed individual is unprotected or unable to find shelter soon enough to avoid excessive exposure.

As noted earlier, natural gas does not explode unless it is in a confined space within a specific range of mixtures with air and is ignited. However, if an explosion does occur, the physiological effects of overpressures depend on the peak overpressure that reaches a person. Exposure to overpressure levels can be fatal. People located outside the flammable cloud when a combustible mixture ignites would be exposed to lower overpressure levels than people inside the flammable cloud. If a person is far enough from the source of overpressure, the explosion overpressure level would be incapable of causing injuries. The generally accepted hazard level for an explosion overpressure is 1.0 psig. This level of overpressure can result in injuries to humans, primarily from flying debris. The consequences of various levels of overpressure are outlined in Table Ap.4.1-2.

Table Ap.4.1-2. Explosion Over-Pressure Damage Thresholds

Side-On Over-Pressure	Damage Description
0.02 psig	Annoying Noise
0.03 psig	Occasional Breaking of Large Window Panes Under Strain
0.04 psig	Loud Noise; Sonic Boom Glass Failure
0.10 psig	Breakage of Small Windows Under Strain
0.20 psig	Glass Breakage – No Injury to Building Occupants
0.30 psig	Some Damage to House Ceilings, 10% Window Glass Broken
0.50–1.00 psig	Large and Small Windows Usually Shattered, Occasional Damage to Window Frames
0.70 psig	Minor Damage to House Structures, Injury, but Very Unlikely to Be Serious
1.00 psig	1% Probability of a Serious Injury or Fatality for Occupants in a Reinforced Concrete or Reinforced Masonry Building from Flying Glass and Debris 10% Probability of a Serious Injury or Fatality for Occupants in a Simple Frame, Unreinforced Building
14.5 psig	1% Probability of Death to Those Outdoors

Ap.4.2 Baseline Data

The anticipated frequency of unintentional releases by cause will be developed in this section. The frequencies will be based primarily on the 1981 through 1990 data collected for California's regulated interstate and intrastate hazardous liquid pipelines (*California Hazardous Liquid Pipeline Risk Assessment*, prepared for the California State Fire Marshal, Payne, 1993). This report included a complete inventory of all 7,800 miles of interstate and intrastate hazardous liquid pipelines within the State. It also included an audit of all 514 unintentional releases that occurred within this 10-year period. Based on a review of the national and international data available, using this California data is considered appropriate, for the following reasons:

- The California data is the only completely audited, recent, relatively large data sample available. A team of field technicians visited the operational sites of every regulated pipeline operator within the State. The team spent between one and five days at each site reviewing insurance records, unintentional release records, pipeline inventory data, drawings, internal incident reports, etc. and interviewing operator personnel. Using this approach allowed the team to collect data for very small releases, which were not reportable to the regulatory agencies.
- The pipelines included in the California study are representative of the proposed pipeline segment (e.g., similar diameter, variable terrain, all steel, etc.). Specifically, the length weighted mean pipe diameter of these lines was 12.3 inches, the lines were constructed of welded steel pipe operated and maintained to similar regulatory requirements.
- The California data included a complete pipeline inventory and unintentional release data with many parameters. As a result, it allowed the authors to investigate the effects of various operational and design considerations (e.g., operating temperature, period of construction, etc.). The conclusions drawn

from the California study are useful in assessing the risks associated with the proposed pipeline segment. The California study identified the effects of several pipeline parameters on the overall incident rates. Using these data facilitated the development of the anticipated frequency of unintentional releases from the proposed pipeline segment, using actual pipeline construction and operational conditions.

- The reader should note that the frequency of unintentional releases presented in the California study is higher than those reported by other sources. The higher frequency is due to the inclusion of ***all*** releases, regardless of spill volume. Other sources include only releases meeting certain criteria; they typically include only USDOT reportable releases.
- Since the California study included a complete pipeline inventory, including the actual length of pipe installed for each of several parameters (e.g. operating temperature, external coating, type of steel, operating pipe stresses as a function of the specified minimum pipe stress, etc.), the data enabled a very comprehensive statistical analysis. Multinomial logit regressions were performed to evaluate the probability of pipeline unintentional releases considering each of these variables. Using these statistical results and other data, we have developed anticipated pipeline incident rates for this project.

Frequency of Unintentional Releases

In the following paragraphs, we will develop the anticipated unintentional release rate for this pipeline segment.

External Corrosion

The California study found that the frequency of unintentional releases (of all volumes) caused by external corrosion was 4.18 unintentional releases per 1,000 mile-years. However, pipelines constructed in the 1950s had an external corrosion incident rate of 2.47 unintentional releases per 1,000 mile-years; those constructed in the 1960s, 1970s and 1980s had external corrosion incident rates of 1.47, 1.24, and 0.00 unintentional releases per 1,000 mile-years respectively. On the other hand, pipelines constructed before 1940 and those constructed during the 1940s, had external corrosion incident rates of 14.12 and 4.24 unintentional releases per 1,000 years respectively.

The statistical analyses performed in the California study indicated that the decade of pipeline construction directly affected the incident rate. The reader should note that this figure included all spills, regardless of spill volume. The majority of these spills would not require USDOT reporting. As a result, the reader should not attempt to directly compare these values. They can be compared only after the spill volume distribution has been considered.

During the 1940s and 1950s, significant improvements were made in pipeline construction techniques. Relative to external corrosion, the primary improvements included advances in external coatings and more widespread use of these coatings and cathodic protection systems. We believe that these items account for the significant reduction in external corrosion incident rates for modern pipelines, versus pipelines constructed prior to the 1940s. For newer pipelines, it is impossible to isolate the individual affects of pipe age and other improvements (e.g. technology, construction techniques, the more widespread use of high quality external coatings and cathodic protection systems). Table Ap.4.2-1 presents the California data by decade of pipeline construction.

Effects of Operating Temperature on External Corrosion

The statistical analyses performed in the California study indicated that operating temperature directly affected the frequency of unintentional releases. Considering all pipelines, regardless of decade of construction, those that were operated near ambient temperatures had an external corrosion caused incident rate of 1.33 unintentional releases per 1,000 mile-years. The incident rate rose dramatically as the operating temperature was increased.

Table Ap.4.2-1. Incident Rates by Decade of Construction

Incident Cause	Pre-1940	1940-49	1950-59	1960-69	1970-79	1980-89
External Corrosion	14.12	4.24	2.47	1.47	1.24	0.00
Internal Corrosion	0.38	0.27	0.10	0.16	0.00	0.28
3rd Party - Construction	1.96	1.06	0.68	0.66	0.25	0.28
3rd Party - Farm Equipment	0.53	1.33	0.05	0.00	0.00	0.00
3rd Party - Train Derailment	0.00	0.00	0.00	0.05	0.25	0.00
3rd Party - External Corrosion	0.45	0.00	0.10	0.33	0.00	0.00
3rd Party - Other	0.30	0.13	0.05	0.05	0.00	0.00
Human Operating Error	0.30	0.13	0.00	0.11	0.25	0.00
Design Flaw	0.08	0.00	0.00	0.00	0.00	0.14
Equipment Malfunction	0.38	0.53	0.10	0.60	1.24	0.00
Maintenance	0.00	0.00	0.24	0.00	0.00	0.00
Weld Failure	0.38	0.27	0.15	0.44	0.25	0.00
Other	0.83	0.13	0.24	0.27	0.25	0.28
Total	19.71	8.09	4.18	4.14	3.73	0.98

Source: Payne (EDM Services, Inc.), 1993

The proposed pipeline segment will be operated at ambient temperatures. Table Ap.4.2-2 indicates that the external corrosion incident rates for the California lines operated at various temperatures ranged from 0.48 to 11.36 unintentional releases per 1,000 mile-years. However, the lines operated between 130°F and 159°F had a 1947 mean year of pipeline construction; as discussed earlier, pipe age also significantly affected the incident rate. This effect is also reflected in these data.

Table Ap.4.2-2. Incident Rates by Design Operating Temperature

Incident Cause	0-69°F	70-99°F	100-129°F	130-159°F	160°F+
External Corrosion	0.48	1.33	7.11	11.36	11.31
Internal Corrosion	0.00	0.21	0.32	0.57	0.08
3rd Party - Construction	1.91	0.94	0.95	0.57	0.60
3rd Party - Farm Equipment	0.00	0.30	0.47	0.00	0.08
3rd Party - Train Derailment	0.00	0.04	0.00	0.00	0.00
3rd Party - External Corrosion	0.00	0.06	0.16	0.00	0.15
3rd Party - Other	0.00	0.24	0.16	0.00	0.15
Human Operating Error	0.00	0.11	0.00	0.00	0.23
Design Flaw	0.00	0.04	0.00	0.00	0.00
Equipment Malfunction	0.00	0.24	0.16	0.57	0.98
Maintenance	0.00	0.09	0.16	0.00	0.00
Weld Failure	0.00	0.19	0.32	0.00	0.60
Other	0.00	0.21	1.11	1.14	0.45
Total	2.39	4.00	10.92	14.21	14.63

Source: Payne (EDM Services, Inc.), 1993

Overall Effects of External Corrosion

External corrosion of a buried pipe is an electro-chemical reaction, which can occur when bare (un-coated) steel is in contact with the earth. The moist soil surrounding a pipeline can serve as an electrolyte. When this occurs, the pipe can become an anode. The current then flows through the electrolyte, from the anode (pipe) to the cathode (soil). In this instance, the anode (pipe) loses material (corrodes) as this process occurs.

The intent of an effective external corrosion prevention program is twofold. First, the pipe is protected from corrosion by insulating it from contact with the electrolyte using an external coating. Second, in the event that the coating should fail, the pipe is prevented from becoming the anode by introducing some other material into the electrochemical chain that is more anodic than the pipe, or appears to be because of an impressed current. An impressed current or sacrificial anode cathodic protection system makes the current flow through the soil, toward the pipe, instead of away from it; thus, external corrosion is eliminated.

An impressed current system takes alternating current electrical power from a utility source or solar panels. A transformer is used to reduce the voltage. A rectifier then converts the alternating current to a direct current. The direct current flows to and through anodes (graphite, steel, or other material) and into the surrounding earth. At locations where there may be a break in the external pipe coating (holiday), the current will reach the pipeline. It will then flow along the line to the rectifier, completing the circuit, preventing external corrosion at the external pipe coating holiday.

As noted earlier, external corrosion typically causes a relatively large percentage of unintentional releases. Often, these releases are relatively small in volume, with low release rates. However, they can go unnoticed for long periods of time.

External Corrosion Mitigation Measures

To mitigate the likelihood of releases caused by external corrosion, the following mitigation measures will be undertaken by the Applicant:

- **Modern External Pipe Coating.** The proposed pipeline segment will be externally coated with fusion-bonded epoxy (FBE) external coating.
- **Impressed Current Cathodic Protection System.** The proposed pipe segments will have impressed current cathodic protection systems.
- **Monitoring.** At least once each calendar year, at intervals not exceeding 15 months, natural gas pipeline operators are required to test their cathodic protection system in accordance with 49 CFR 192.465.
- **Visual Inspections.** Each time buried pipe is exposed for any reason, it will be examined for evidence of external corrosion in accordance with 49 CFR 192.459. If active corrosion is found, the operator is required to investigate and determine the extent. Pipeline operators are required to maintain records of these USDOT required inspections. They are routinely reviewed by USDOT staff during their inspections.

Using the data presented in Tables Ap.4.2-1 and Ap.4.2-2, as well as the applicant's proposed mitigation measures, we have developed an opinion of the anticipated unintentional releases due to external corrosion from the proposed pipe segments. These segments will normally be operated at ambient temperatures, using externally coated pipe, with an impressed current cathodic protection system; in our opinion, the anticipated frequency of external corrosion caused unintentional releases will be approximately 1.0 unintentional releases per 1,000 mile-years. We believe that this proposed anticipated frequency of unintentional releases is valid, based on historic data and the specific pipe parameters. The proposed frequency is intended to reflect the average value over a 50-year project life. During the early years of operation, we would expect the frequency of these incidents to approach zero. It should also be noted that the statistical impact of the new USDOT pipeline integrity regulations are unknown at this time. But they will likely have no impact on the proposed pipeline components, since they are located outside any HCA and are not required to be included in a Pipeline Integrity Management Plan.

Internal Corrosion

49 CFR 192.475 and 477 outline the regulatory requirements for internal corrosion control and monitoring. Some of these requirements include:

- "Corrosive gas may not be transported by pipeline, unless the corrosive effect of the gas on the pipeline has been investigated and steps have been taken to minimize internal corrosion."
- "If corrosive gas is being transported, coupons or other suitable means must be used to determine the effectiveness of the steps taken to minimize internal corrosion. Each coupon or other means of monitoring internal corrosion must be checked two times each calendar year, but with intervals not exceeding 7½ months."
- "Whenever any pipe is removed from the pipeline for any reason, the internal surface must be inspected for evidence of corrosion . . . ."

Although the possibility of an internal corrosion/erosion caused unintentional release is low, the possibility does exist. Using these data, a frequency of 0.2 unintentional releases per 1,000 mile-years has been used for unintentional releases caused by internal corrosion. This is the rate presented in the California study. The proposed frequency is intended to reflect the average value over a 50-year project life. During the early years of operation, we would expect the frequency of these incidents to approach zero.

Third Party Damage

Like external corrosion, third party damage causes a large percentage of accidental pipeline releases. As noted earlier in Table Ap.4.2-1, approximately 20–30% of the unintentional releases have reportedly been caused by third parties. The applicant plans to employ several mitigation measures to reduce the frequency of third party caused releases. These include:

- **One-Call System.** The applicant will subscribe to the USA North underground service alert "one-call" system. A toll free number is available for contractors and others to use before they begin excavations. Once a contractor calls and identifies its proposed excavation location, the organization notifies the underground facility owners in the vicinity. The owners respond to these calls with personal communications with the excavator. If their facilities are nearby, they mark the location of their facilities on the ground, so third party intrusions can be avoided. Participation in a one-call system if required as part of an operator's damage prevention program, per 49 CFR 192.614.
- **Line Marking.** The applicant is required by law (49 CFR 192.707) to install line marker posts such that the pipeline is readily identifiable. In addition, they are required to have warning signs installed at each side of road, railroad, and waterway crossings, and at fence lines across open or agricultural property, crossings of other lines (e.g. irrigation, oil, gas, telephone, utilities) where practical, and where the line is above ground in areas accessible to the public
- **Right-of-Way Patrolling.** 49 CFR 192.705 requires, each operator to have a patrol program to monitor for indications of leaks, nearby construction activity, and any other factors that could affect safety and operation. The frequency of these inspections is based on a number of factors. For the proposed line, these patrols mush be conducted at least twice each calendar year for road crossings and once each calendar year in other locations.
- **Leakage Surveys.** A leakage survey must be conducted at least once each calendar year.
- **Public Education.** 49 CFR 192.616 requires pipeline operators to develop and implement a written continuing public education program that follows the guidance provided in the American Petroleum Institute's (API's) Recommended Practice 1162 Public Awareness Programs for Pipeline Operators as their public education procedure.

The California study found that the overall frequency of third party damage caused unintentional releases was 1.46 unintentional releases per 1,000 mile-years. For pipelines constructed in the 1950s, the frequency was only 0.88 unintentional releases per 1,000 mile-years; it was even lower for newer lines. We believe that these lower values were primarily due to the increased awareness of the threat from third party damage to pipeline facilities; newer lines have benefited from improved line marking, one-call dig alert systems, avoidance of high risk areas, improved documentation, increased depth of cover, and public awareness programs.

We estimate that the frequency of third party damage caused unintentional releases for all volume releases from the existing line will be approximately 0.4 incidents per 1,000 mile-years.

Human Operating Error

49 CFR 192 provides specific requirements for pipeline operations and maintenance manuals and procedures. It also requires that all operations and maintenance personnel be adequately trained. Historically, human operator error has not been a major cause of pipeline unintentional releases.

We estimate the frequency of unintentional releases caused by human operating error will be 0.1 unintentional releases per 1,000 mile-years. This rate is based on the data obtained from the California study.

Design Flaw

Based on the California data, we estimate the frequency of unintentional releases caused by design flaw/ error will be 0.03 unintentional releases per 1,000 mile-years. Although these unintentional releases are rare, they do occur. Often, an unintentional release that is caused by a design flaw is categorized improperly. The designation of a unintentional release cause is often subjective. For example, should a pipeline be severed during a landslide, the operator may indicate that the cause was third party damage. However, it may have been a design error or oversight that placed the pipeline within the geo-hazard in the first place. We do not believe that design errors can be eliminated. We believe that the proposed frequency of unintentional releases is reasonable.

Equipment Malfunction

We estimate the frequency of equipment malfunction caused unintentional releases will be 0.4 unintentional releases per 1,000 mile-years. This rate is consistent with the California study.

Maintenance

We estimate the frequency of improper maintenance caused unintentional releases will be 0.07 unintentional releases per 1,000 mile-years, based on the California study.

Weld Failure

Based on the California study, we estimate that the frequency of unintentional releases causes by weld failure will be 0.3 unintentional releases per 1,000 mile-years.

Other or Unknown

Based on the California study, we estimate that the frequency of unintentional releases caused by other or unknown sources will be 0.5 unintentional releases per 1,000 mile-years.

Likelihood of Unintentional Releases

Using the data described above, we expect that the frequency of unintentional releases for all spills, regardless of volume, will be 3.0 unintentional releases per 1,000 mile-years.

Frequency of Injuries and Fatalities

In the following paragraphs, we will estimate the frequency of human life impacts using data from the following sources:

- United States Natural Gas Transmission and Gathering Lines (U.S. Department of Transportation [USDOT]) – 1970 through December 15, 2005
- United States Interstate Hazardous Liquid Pipelines (USDOT) – 1984 through 1998
- California Regulated Interstate and Intrastate Hazardous Liquid Pipelines (Payne, 1993) – 1981 through 1990.

Each of these data sets provides pipeline incident data for reportable incidents. However, the criteria for reporting incidents differ for each source. This makes direct comparison of the individual results difficult. On the other hand, it provides a methodology for estimating incident rates for a variety of consequences.

U.S. Natural Gas Transmission and Gathering Lines (USDOT) - 1970 to June 1984

Since the USDOT natural gas pipeline reporting criteria changed in June 1984, the incident reports beginning in July 1984 have been summarized separately, in the next section of this document. The criteria for natural gas releases to be reported to the USDOT for inclusion in this data were as follows:

- Resulted in a death or injury requiring hospitalization
- Required the removal from service of any segment of a transmission pipeline
- Resulted in gas ignition
- Caused an estimated damage to the property owner, or of others, or both, of $5,000 or more
- Involved a leak requiring immediate repair
- Involved a test failure that occurred while testing either with gas or another test medium, or
- In the judgment of the operator, was significant even though it did not meet any of the above criteria.

Table Ap.4.2-3. U.S. Natural Gas Transmission and Gather Lines (USDOT) – 1970 to June 1984

Consequence	Frequency
Frequency of Reportable Unintentional Releases	1.3 incidents per 1,000 mile-years
Frequency of Reportable Injuries	0.096 injuries per 1,000 mile-years
Frequency of Fatalities	0.016 fatalities per 1,000 mile-years

The frequencies of the various consequences reported during this period are summarized in Table Ap.4.2-3.

It should be noted that during this 14½-year period, 36 (50%) of the total 72 fatalities and 161 (59%) of the total 274 of those injured were employees of the operating company.

U.S. Natural Gas Transmission and Gathering Lines (USDOT) – July 1984 through 2005

In June 1984, the USDOT changed the criteria for reporting natural gas releases. The most significant change was that in general, leaks causing less than $50,000 property damage no longer required reporting to the USDOT. Since this value is significantly greater than the prior $5,000 reporting criteria, a significant decrease in the resulting reportable incident rate resulted. But the frequency of fatalities remained essentially constant. These data are summarized in Table Ap.4.2-4.

Table Ap.4.2-4. U.S. Natural Gas Transmission and Gather Lines (USDOT) – July 1984 through 2001

Consequence	Frequency
Frequency of Reportable Unintentional Releases	0.29 incidents per 1,000 mile-years
Frequency of Reportable Injuries	0.051 injuries per 1,000 mile-years
Frequency of Fatalities	0.014 fatalities per 1,000 mile-years

The criteria for natural gas releases to be reported to the USDOT from July 1984 through the present were as follows:

- Events which involved a release of gas from a pipeline, or of liquefied natural gas (LNG) or gas from an LNG facility, which caused: (a) a fatality, or personal injury necessitating inpatient hospitalization; or (b) estimated property damage, including costs of gas lost by the operator, or others, or both, of $50,000 or more.
- An event which resulted in an emergency shut-down of an LNG facility.
- An event that was significant, in the judgment of the operator, even though it did not meet the criteria above.

The average length of U.S. transmission lines during the 17½-year period through 2001 was 293,206 miles.

Beginning in 2002, the USDOT changed their reporting forms. At this time, operators were required to begin reporting additional data for each reportable release. These changes were significant. Some of the additional reporting fields included the reporting of fires and explosions, which were not required to be identified previously. From 2002 through December 2005, there were a total of 463 reportable incidents, including 23 reportable injuries, and 6 fatalities. The average annual transmission pipeline mileage was 300,510 miles for the years 2002 through 2004. Using these data, the frequency of reportable incidents during this most recent four year period was 0.39 incidents per 1,000 mile-years. The injury and fatality rates were 0.019 and 0.005 incidents per 1,000 mile-years respectively.

U.S. Hazardous Liquid Pipelines (USDOT) – 1984 through 1998

The criteria for hazardous liquid pipeline incidents to be reported to the USDOT for inclusion in this data set were as follows:

- Explosion or fire not intentionally set by the operator
- Loss of more than 50 barrels (2,100 gallons) of liquid or carbon dioxide
- Escape to the atmosphere of more than five barrels per day of highly volatile liquid
- Death of any person

Table Ap.4.2-5. U.S. Hazardous Liquid Pipelines (USDOT) – 1984 through 1998

Consequence	Frequency
Frequency of Reportable Unintentional Releases	1.29 incidents per 1,000 mile-years
Frequency of Reportable Injuries	0.076 injuries per 1,000 mile-years
Frequency of Fatalities	0.015 fatalities per 1,000 mile-years

Note: The 1994 Annual Report on Pipeline Safety excluded 1,851 individuals who were injured with minor burns and vapor inhalation from the failure and ignition of seven hazardous liquid pipelines during the San Jacinto River floods in mid-October, 1994, near Houston, Texas. These incidents were caused by severe flooding in the area. These injuries are not included in the injury rate shown above.

- Bodily harm to any person resulting in loss of consciousness, necessity to carry the person from the scene, or disability which prevents the discharge of normal duties or the pursuit of normal activities beyond the day of the accident, and/or
- Estimated property damage to the property of the operator, or others, or both, exceeding $5,000, prior to June 1994. After June 1994 this criterion was changed to $50,000, including the cost of clean-up, recovery, and the value of any lost product.

It is interesting to note that the incident rate for hazardous liquid pipeline releases (prior to 1994) was essentially the same as those for reportable U.S. natural gas transmission and gathering lines from 1970 through June 1984, which had a similar $5,000 property damage reporting requirement.

Regulated California Hazardous Liquid Pipelines – 1981 through 1990

This study, undertaken by the California State Fire Marshal, Pipeline Safety Division, included all regulated California interstate and intrastate hazardous liquid pipelines. It included approximately 7,800 miles of pipeline data, over a ten-year period (1981 to 1990). The systems included in this study had complete release records. The major difference for this study, as compared to ones discussed previously, is that all releases, regardless of size, cause, extent of property damage, or extent of injury were included in the study. Also, a complete audit of the pipeline inventory and release data was conducted. As a result, the incident rates resulting from this study were higher than presented in other studies, which included only reported releases fitting a relatively narrow set of criteria. A summary of these results is included in Table Ap.4.2-6.

Table Ap.4.2-6. California Interstate and Intrastate Hazardous Liquid Pipelines – 1981 through 1990

Consequence	Frequency
Frequency of All Unintentional Releases	7.08 incidents per 1,000 mile-years
Frequency of Injuries	0.685 injuries per 1,000 mile-years
Frequency of Fatalities	0.042 fatalities per 1,000 mile-years

Summary of Historical Pipeline Release Data

In Table Ap.4.2-7, the available pipeline release data have been summarized.

Table Ap.4.2-7. Anticipated Frequency Comparison for Various Consequences

Consequence	U.S. Natural Gas Transmission 1970 to June 1984	U.S. Natural Gas Transmission July 1984 thru 2001	U.S. Natural Gas Transmission 2002 thru 12/15/2005	U.S. Hazardous Liquid 1984–1998	California Hazardous Liquid 1981–1990
Reportable Incidents	1.3 ($5,000 criteria)	0.29 ($50,000 criteria)	0.39 ($50,000 criteria)	1.29 ($5,000 criteria)	7.08 (all incidents)
Injuries regardless of severity	N/A	N/A	N/A	N/A	0.685
Injury requiring hospitalization	0.096	0.051	0.019	N/A	N/A
Injuries requiring hospitalization, causing loss of consciousness, or preventing discharge of normal duties day following the incident	N/A	N/A	N/A	0.076	N/A
Fatalities	0.016	0.014	0.005	0.015	0.042 (See Note 2)

Notes: 1. The frequencies shown above are in units of incidents per 1,000 mile-years.
2. There were only three (3) fatalities during this 10-year study period. With the relatively small data sample, the resulting fatality rate was significantly affected.

Ap.4.3 Qualitative Risk Assessment

Anticipated Frequency of Releases

Using the data compiled in the previous section, the anticipated frequencies of unintentional releases by various causes have been estimated. These data, for the various pipeline components, are shown in Tables Ap.4.3-1 through Ap.4.3-3 below. These data also include anticipate releases from the metering and compression stations, which are also under USDOT jurisdiction and are subject to the pipeline incident reporting requirements.

Table Ap.4.3-1. Anticipated Frequency of Unintentional Releases from Proposed 5.9 Mile, 16-Inch-Diameter Pipeline Segment

Incident Cause	Incident Rate (Unintentional Releases per 1,000 Mile-Years)	Pipeline Segment Length (miles)	Annual Likelihood of Release	Recurrence Interval (years)
External Corrosion	1.00	5.9	0.0059	169
Internal Corrosion	0.20	5.9	0.0012	847
3rd Party - Damage	0.40	5.9	0.0024	424
Human Operating Error	0.10	5.9	0.0006	1,695
Design Flaw	0.03	5.9	0.0002	5,650
Equipment Malfunction	0.40	5.9	0.0024	424
Maintenance	0.07	5.9	0.0004	2,421
Weld Failure	0.30	5.9	0.0018	565
Other	0.50	5.9	0.0030	339
Total, All Releases, Regardless of Spill Volume	3.00	5.9	0.0177	56
USDOT Reportable Gas Releases – 1970 thru June 1984 criteria (>$5,000 damage)	1.30	5.9	0.0077	130
USDOT Reportable Gas Releases – Current Criteria (>$50,000 damage)	0.39	5.9	0.0023	435

Table Ap.4.3-2. Anticipated Frequency of Unintentional Releases From Proposed 1.1-Mile, 12-Inch-Diameter Pipeline Segment

Incident Cause	Incident Rate (Unintentional Releases per 1,000 Mile-Years)	Pipeline Segment Length (miles)	Annual Likelihood of Release	Recurrence Interval (years)
External Corrosion	1.00	1.1	0.0011	909
Internal Corrosion	0.20	1.1	0.0002	4,545
3rd Party - Damage	0.40	1.1	0.0004	2,273
Human Operating Error	0.10	1.1	0.0001	9,091
Design Flaw	0.03	1.1	0.0000	30,303
Equipment Malfunction	0.40	1.1	0.0004	2,273
Maintenance	0.07	1.1	0.0001	12,987
Weld Failure	0.30	1.1	0.0003	3,030
Other	0.50	1.1	0.0006	1,818
Total, All Releases, Regardless of Spill Volume	3.00	1.1	0.0033	303
USDOT Reportable Gas Releases – 1970 thru June 1984 criteria (>$5,000 damage)	1.30	1.1	0.0014	699
USDOT Reportable Gas Releases – Current Criteria (>$50,000 damage)	0.39	1.1	0.0004	2,331

Table Ap.4.3-3. Anticipated Frequency of Unintentional Releases From Proposed 1.35 Mile, 4-Inch-Diameter Pipeline Segment

Incident Cause	Incident Rate (Unintentional Releases per 1,000 Mile-Years)	Pipeline Segment Length (miles)	Annual Likelihood of Release	Recurrence Interval (years)
External Corrosion	1.00	1.35	0.0014	741
Internal Corrosion	0.20	1.35	0.0003	3,704
3rd Party - Damage	0.40	1.35	0.0005	1,852
Human Operating Error	0.10	1.35	0.0001	7,407
Design Flaw	0.03	1.35	0.0000	24,691
Equipment Malfunction	0.40	1.35	0.0005	1,852
Maintenance	0.07	1.35	0.0001	10,582
Weld Failure	0.30	1.35	0.0004	2,469
Other	0.50	1.35	0.0007	1,481
Total, All Releases, Regardless of Spill Volume	3.00	1.35	0.0041	247
USDOT Reportable Gas Releases – 1970 thru June 1984 criteria (>$5,000 damage)	1.30	1.1	0.0014	699
USDOT Reportable Gas Releases – Current Criteria (>$50,000 damage)	0.39	1.1	0.0004	2,331

Anticipated Frequency of Injuries and Fatalities

Most unintentional natural gas releases are relatively small and do not cause personal injuries or death. In this section, the likelihood of human injuries and deaths will be estimated using historical data. Later in this document, the human life impacts will be evaluated using a probabilistic approach.

As noted earlier, the primary natural gas component is methane, which is not toxic. Although methane presents a slight inhalation hazard, the primary risk to humans is posed by fire or explosion. A fire could result from a natural gas release with two conditions present. First, a volume of natural gas must be present within the combustible mixture range (5% to 15% methane in air). Second, a source of ignition must be present with sufficient heat to ignite the air/natural gas mixture (1,000°F). In order for an explosion to occur, a third condition must be present — the natural gas vapor cloud must be confined, at least to some degree.

It is difficult to estimate the potential extent of human injury because there are so many variables affecting the size of a fire or explosion: rate of vapor cloud formation (controlled primarily by the release rate), size of the vapor cloud within the combustible range (controlled by weather, including wind and temperature, release rate, etc.), concentration of vapors (varying with wind and topographic conditions), degree of vapor cloud confinement, etc. (These actual conditions will be evaluated later, in Section Ap.4-4 of this document.)

Based on the historical data presented in the prior Section Ap.4.2, we estimate the frequencies for human life consequences shown in Table Ap.4.3-4.

Table Ap.4.3-4. Anticipated Frequency of Human Life Impacts

Consequence	Frequency
Injuries regardless of severity	0.7 incidents per 1,000 mile-years
Injuries requiring hospitalization	0.05 incidents per 1,000 mile-years
Fatalities	0.01 fatalities per 1,000 mile-years

Using these historical data result in the following anticipated human life impacts.

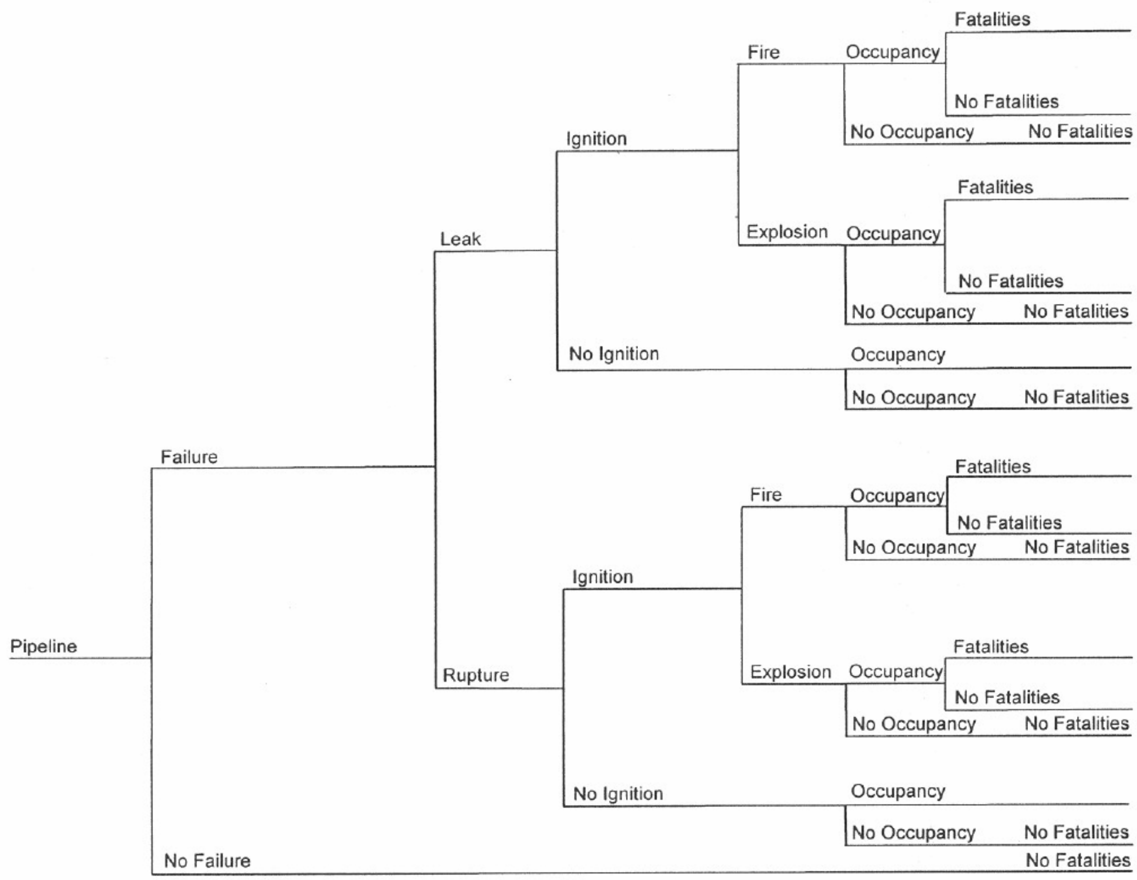
Table Ap.4.3-5. Anticipated Human Life Impacts Based on Historical Data – Recurrence Interval (years)

	A	B	C
Consequence	5.9-Mile, 16-Inch-Diameter Pipeline Recurrence Interval (years)	1.1-Mile, 12-Inch-Diameter Pipeline Recurrence Interval (years)	1.35-Mile, 4-Inch-Diameter Pipeline Recurrence Interval (years)
Injury - regardless of severity	240	1,300	1,100
Injury - requiring hospitalization	3,400	18,000	15,000
Fatality	17,000	91,000	74,000

The frequencies of injuries and fatalities presented above are useful references. However, they do not facilitate an accurate evaluation of the specific parameters for the proposed pipeline facilities. For example, these summary data do not differentiate between the risks of a relatively benign natural gas pipeline and a liquefied petroleum gas (LPG) pipeline, which is much more likely to result in serious impacts due to fires and explosions. These historical data also do not differentiate between various population densities. For example, a release in an urban area is likely to cause more significant impacts to humans than a release in a rural, undeveloped area. For the rural setting of the proposed facilities, the values shown above may significantly overstate the risk to the public. In the following section, a probabilistic risk assessment will be presented. This analysis will consider the actual open environment, pipe contents, pipe diameter, actual operating conditions and the proximity to public areas.

Ap.4.4 Quantitative Risk Assessment

In this section, a probabilistic pipeline risk assessment will be presented. This analysis will consider the actual site population density, as well as the characteristics of the pipe contents in the event of an unintentional release. This analysis will be conducted using the following consequence event tree:



Baseline Frequency of Unintentional Releases

For this analysis, a baseline frequency of USDOT reportable unintentional releases of 0.39 incidents per 1,000 mile-years has been used. This is the actual frequency of reportable natural gas transmission pipeline releases from 2002 through December 15, 2005

Conditional Consequence Probabilities

In order to conduct a probabilistic analysis, the conditional probabilities of each fault tree branch must be established. For example, what percentage of pipe failures are relatively small leaks versus full bore ruptures? What percentage of vapor clouds resulting from leaks and ruptures are ignited? What percentage of ignited vapor clouds burn versus explode? And in the event of a fire or explosion, do any serious injuries or fatalities result?

The Federal Emergency Management Agency (FEMA), *Handbook of Chemical Hazard Analysis Procedures*, 1989, provides conditional probabilities for pipeline releases. These data are presented below:

Table Ap.4.4-1. FEMA Conditional Probabilities

Parameter	Conditional Consequence Probability	Value – Source
Leak Size	Probability of Release (1-inch-diameter hole)	80% – FEMA
	Probability of Rupture (complete, full diameter pipe severance)	20% – FEMA
Ignition	Probability of No-Ignition	70% – FEMA
	Probability of Ignition	30% – FEMA
Fire/Explosion	Probability of Fire Upon Ignition	70% – FEMA
	Probability of Explosion Upon Ignition	30% – FEMA

Regarding spill size distribution, FEMA assumes that 20% of the unintentional releases are full pipeline ruptures, severing the complete pipe diameter; and 80% of the releases approximate a 1-inch-diameter hole in the line. FEMA further assumes that 30% of these released contents are exposed to an ignition source. In 70% of these ignited releases, a fire will result; while 30% of the time, an explosion will result. The FEMA data may be combined as follows:

Table Ap.4.4-2. FEMA Combined Conditional Probabilities

Fires vs. Explosions	Conditional Release Consequence	Value
Fires	Pipeline Release Resulting in a Fire	0.8 x 0.3 x 0.7 = 16.8%
	Pipeline Rupture Resulting in a Fire	0.2 x 0.3 x 0.7 = 4.2%
Explosions	Pipeline Release Resulting in an Explosion	0.8 x 0.3 x 0.3 = 7.2%
	Pipeline Rupture Resulting in an Explosion	0.2 x 0.3 x 0.3 = 1.8%

For natural gas transmission pipelines, the FEMA data is conservative. This can be demonstrated by analyzing some of the actual unintentional release data reported to the Department of Transportation, Office of Pipeline Safety (USDOT) and comparing it to the FEMA assumptions. Unfortunately, the USDOT incident reports prior to January 1, 2002 did not include fields for reporting fires or explosions; these fields were added in 2002. Between January 1, 2002 and December 15, 2005, there were 463 transmission pipeline incidents reported to the USDOT. Sixty-five (14%) of the resulting vapor clouds were ignited. 60% of the vapor clouds simply burned, while 40% of the vapor clouds exploded; this resulted in thirty-nine (39) fires and twenty-six (26) explosions. In other words, 8.4% of the natural gas transmission pipeline incidents resulted in fires while 5.6% resulted in explosions. The FEMA data predicts that 21% of the releases result in a fire (16.8% plus 4.2%), while 9% (7.2% plus 1.8%) of the incidents result in explosions. Thus, the FEMA data overstates the probability of fire and explosions resulting from unintentional natural gas transmission releases by factors of 2.5 and 1.6 respectively.

It is interesting to note that between January 1, 2002 and December 15, 2005, forty (40) of the reported 463 natural gas transmission pipeline incidents occurred in compressor stations; ten (10) of these incidents resulted in fires and eight (8) resulted in explosions. Twenty-four (24) of the reported incidents occurred at meter and/or regulator stations; four (4) of these resulted in fires and one (1) resulted in an explosion.

The conservative FEMA data are intended to apply to all pipeline contents; however, they do not account for the differences in physical characteristics. However, some contents are far less flammable and explosive than others. In order to account for these differences, the FEMA probabilities will be adjusted to match the actual USDOT natural gas transmission pipeline data. In the probabilistic analysis, the following data will be used.

Table Ap.4.4-3. Conditional Probabilities Used In Analysis

Parameter	Conditional Consequence Probability	Value – Source
Leak Size	Probability of Release (1-inch-diameter hole)	80% – FEMA
	Probability of Rupture (complete, full diameter pipe severance)	20% – FEMA
Ignition	Probability of No-Ignition	86% – USDOT
	Probability of Ignition	14% – USDOT
Fire/Explosion	Probability of Fire Upon Ignition	60% – USDOT
	Probability of Explosion Upon Ignition	40% – USDOT

Table Ap.4.4-4. FEMA Combined Conditional Probabilities

Fires vs. Explosions	Conditional Release Consequence	Value
Fires	Pipeline Release Resulting in a Fire	0.8 x 0.14 x 0.6 = 6.7%
	Pipeline Rupture Resulting in a Fire	0.2 x 0.14 x 0.6 = 1.7%
Explosions	Pipeline Release Resulting in an Explosion	0.8 x 0.14 x 0.4 = 4.5%
	Pipeline Rupture Resulting in an Explosion	0.2 x 0.14 x 0.4 = 1.1%

The data presented in the table above closely matches the actual fire and explosion data. Specifically, this model assumes that the frequency of releases resulting in a fire is 0.033 incidents per 1,000 mile-years ((6.7% + 1.7%) x 0.39 incidents per 1,000 mile-years). For the four years of available data beginning in 2002, these data would predict a total of 40 fires. During this period there were actually 39 incidents resulting in fires. For explosions, this model assumes that the frequency of releases resulting in an explosion is 0.022 incidents per 1,000 mile-years ((4.5% + 1.1%) x 0.39 incidents per 1,000 mile-years). For the four years of available data beginning in 2002, these data would predict a total of 26 explosions. During this period there were actually 26 incidents resulting in explosions. As a result, these data are appropriate for evaluating the life safety impacts from the proposed natural gas pipeline components.

Release Modeling

In this section, various pipeline release scenarios will be presented. The releases were modeled using CANARY, by Quest, version 4.2 software. For vapor cloud explosion modeling, this software uses the Baker-Strehlow model to determine peak side-on over-pressures as a function of distance from a release. The CANARY software also uses a torch fire model to determine heat radiation flux as a function of distance from a release. Literally thousands of possible data combinations could be used to evaluate individual releases. However, in order to make a reasonable determination of likely releases, the following assumptions were used:

Table Ap.4.4-5. CANARY Release Model Input Assumptions

Parameter	Data Point
Operating Pressure	900 psig for 16-inch-diameter, 5.9-mile, transmission pipeline 1,450 psig for 12-inch-diameter, 1.1-mile, flow line 900 psig for 4-inch-diameter, 1.35-mile, temporary line
Typical Flow Rate	50 MMSCFD for 16-inch transmission pipeline and 12-inch flow line 10 MMSCFD for 4-inch temporary line

Table Ap.4.4-5. CANARY Release Model Input Assumptions

Parameter	Data Point
Modeled Releases	1-inch-diameter release Full Bore release
Contents	Methane
Contents Temperature	70° F
Wind Speed	2 meters per second (4.5 mph) for vapor cloud explosion modeling 20 mph for torch fire modeling
Stability Class	D – Pasquill-Gifford atmospheric stability is classified by the letters A through F. Stability can be determined by three main factors: wind speed, solar insulation, and general cloudiness. In general, the most unstable (turbulent) atmosphere is characterized by stability class A. Stability A occurs during strong solar radiation and moderate winds. This combination allows for rapid fluctuations in the air and thus greater mixing of the released gas with time. Stability D is characterized by fully overcast or partial cloud cover during daytime or nighttime, and covers all wind speeds. The atmospheric turbulence is not as great during D conditions, so the gas will not mix as quickly with the surrounding atmosphere. Stability F generally occurs during the early morning hours before sunrise (no solar radiation) and under low winds. This combination allows for an atmosphere which appears calm or still and thus restricts the ability to actively mix with the released gas. A stability classification of "D" is generally considered to represent average conditions.
Relative Humidity	70%
Air and Surface Temperature	72° F
Continuous Release Duration	120 minutes
Duration of Normal Flow after Leak Initiation	10 minutes for complete pipeline ruptures. It is assumed that the automatic shut-down systems will initiate valve closures and shut-down within 10 minutes of a pipeline rupture. 120 minutes for all 1-inch-diameter release and full bore rupture of 4-inch line.
Pipe Length Upstream and Downstream of Break	½ of 5.9 miles for 16-inch-diameter transmission line ½ of 1.1 miles for 12-inch-diameter flow line ½ of 1.35 miles for 4-inch-diameter temporary line Note: These values assume that the line segment will be isolated within the time frames shown above for line isolation — 10 minutes for complete rupture of the 16-inch and 12-inch lines and 120 minutes for all 1-inch-diameter releases and the complete rupture of the 4-inch line.
Release Angle	45° above horizontal
Fuel Reactivity	Low – Most hydrocarbons have medium reactivity, as defined by the Baker-Strehlow method. Low reactivity fluids include methane, natural gas (98+% methane), and carbon monoxide. High reactivity fluids include hydrogen, acetylene, ethylene oxide, and propylene oxide.
Obstacle Density	Low – This parameter describes the general level of obstruction in the area including and surrounding the confined (or semi-confined) volume. Low density occurs in open areas or in areas containing widely spaced obstacles. High density occurs in areas of many obstacles, such as tightly packed process areas or multi-layered pipe racks.
Flame Expansion	2.5 D – This parameter defines the number of dimensions available for flame expansion. Open areas are 3-D, and produce the smallest levels of overpressure. 2.5-D expansions are used to describe areas that quickly transition from 2-D to 3-D. Examples include compressor sheds and the volume under elevated fan-type heat exchangers. 2-D expansions occur within areas bounded on top and bottom, such as pipe racks, offshore platforms, and some process units. 1-D expansion may occur within long confined volumes such as hallways or drainage pipes, and produce the highest overpressures.
Reflection Factor	2 – This factor is used to include the effects of ground reflection when an explosion is located near grade. A value of 2 is recommended for ground level explosions.

Explosion Modeling Results

As discussed previously, natural gas generally does not explode, unless the vapor cloud is confined in some manner. The proposed pipeline corridors are surrounded by very open, rural land. As a result, there is insufficient confinement to cause a significant vapor cloud explosion, except for a confined release within the compressor building. (The site will be secured and the public will not have access to the compressor building.)

Vapor cloud explosions from each of the three pipeline segments have been analyzed. The peak overpressure was only 0.44 psig, due to the open surroundings and lack of confinement. To put this into perspective, this level of overpressure would likely break 10% to 20% of the windows exposed. This level is far less that the 0.70 psig overpressure required to cause minor damage to residential structures or cause minor injuries; this level is far less than that required to cause serious injuries or deaths. The distance from the pipeline release to various overpressure levels are provided below, for each of the modeled releases.

Table Ap.4.4-6. Pipeline Release Analysis, Vapor Cloud Explosion Results

Release	Operating Pressure	Distance from Unintentional Release (feet)		
		0.20 psig Overpressure	0.40 psig Overpressure	0.44 psig Overpressure
16-inch Pipeline Full Bore Release @ 45°	900 psig	258	126	113
16-inch Pipeline 1" Diameter Release @ 45°	900 psig	48	24	21
12-inch Flow Line Full Bore Release @ 45°	1,450 psig	225	110	98
12-inch Flow Line 1" Diameter Release @ 45°	1,450 psig	65	32	28
4-inch Temporary Full Bore Release @ 45°	900 psig	62	30	27
4-inch Temporary 1" Diameter Release @ 45°	900 psig	46	23	20

Fire Modeling Results

As indicated in the torch fire results table below, for a pipeline rupture, one would expect a radiant heat flux of 3,500 btu/hour-square-foot (second degree skin burns after ten seconds of exposure, 15% probability of fatality if prolonged exposure) at up to roughly 115 feet from a full bore release from the 16-inch-diameter transmission pipeline. The distance from the unintentional release to radiant heat flux values of 1,600 and 440 btu/hour-square foot are anticipated to be 144 feet and 219 feet, respectively.

For the proposed pipeline segments, the fire impacts that could result in an injury are limited to relatively short distances from the release. Since these distances are relatively short, one would generally expect affected individuals to find shelter or move beyond the impacted distance before they could be fatally injured. In these cases, one would only have to move slightly over 100 feet from the release to avoid potentially serious or fatal injuries. As a result, it is highly probable that affected individuals would avoid serious injuries and fatalities resulting from torch fires.

Table Ap.4.4-7. Pipeline Release Analysis, Torch Fire Results

Release	Operating Pressure	Distance from Unintentional Release (feet) 3,500 btu/hr-sq-ft (11.0 kW/m²)	1,600 btu/hr-sq-ft (5.0 kW/m²)	440 btu/hr-sq-ft (1.4 kW/m²)
16-inch Pipeline Full Bore Release @ 45°	900 psig	115	144	219
16-inch Pipeline 1" Diameter Release @ 45°	900 psig	97	129	210
12-inch Flow Line Full Bore Release @ 45°	1,450 psig	113	141	216
12-inch Flow Line 1" Diameter Release @ 45°	1,450 psig	97	129	210
4-inch Temporary Full Bore Release @ 45°	900 psig	51	64	97
4-inch Temporary 1" Diameter Release @ 45°	900 psig	48	62	99

Flash fires occur when a vapor cloud is formed, with some portion of the vapor cloud within the combustible range, and the ignition is delayed. (If the ignition is immediate, a torch fire results.) In a flash fire, the portion of the vapor cloud within the combustible range burns quickly. It is assumed that those within the combustible portion of the vapor cloud would likely be seriously injured or killed. Those outside the combustible portion of the vapor cloud would likely be uninjured. In other words, the public would generally be safe if they were too close to the pipeline (over rich mixture, above the upper flammable limit) or beyond the portion of the vapor cloud with concentrations below the lower flammability limit. The results of the flash fire modeling are shown in Table Ap.4.4-8.

Table Ap.4.4-8. Pipeline Release Analysis, Flash Fire Results

Release	Operating Pressure	Distance from Unintentional Release (feet) Lower Flammability Limit (LFL)	Upper Flammability Limit (UFL)
16-inch Pipeline Full Bore Release @ 45°	900 psig	169	65
16-inch Pipeline 1" Diameter Release @ 45°	900 psig	31	11
12-inch Flow Line Full Bore Release @ 45°	1,450 psig	147	57
12-inch Flow Line 1" Diameter Release @ 45°	1,450 psig	41	15
4-inch Temporary Full Bore Release @ 45°	900 psig	39	15
4-inch Temporary 1" Diameter Release @ 45°	900 psig	29	10

For the purposes of analyzing the potential risk to humans, we have made the following assumptions:

- **Torch Fires versus Flash Fires.** The USDOT data does not provide any data regarding the type of fire (torch versus flash) resulting from natural gas pipeline releases. However, since there are a relatively large number of reported explosions, it is likely that the number of flash fires is somewhat limited. For the purposes of this analysis, we have assumed that 25% of the fires are flash fires and 75% are torch fires.

- **Residences.** For the purposes of calculating average distances, we have used the nearest distance to the residence. For individuals outside there homes, we have assumed that they would be located near the primary structure at the time of an unintentional release.
- **Flash Fire Exposures.** We have assumed a 100% probability of serious injury or fatality to those exposed to a flash fire. However, we have assumed that those housed within their residence would be sufficiently protected to prevent serious injury or fatality. We have also assumed that those protected inside the residence would be able to evacuate safely from their residence should it catch fire from the event. We have assumed that occupants of these residences would be outside their homes, exposed to flash fire effects, 10% of the time (roughly 17 hours per week).
- **Torch Fire Exposures.** This analysis assumes that residents of all buildings within the 3,500 Btu/hour-square-foot heat flux contour will be exposed to a 0.15 probability of fatality while they are outside their homes. We have assumed that these individuals will be sheltered from radiant heat impacts while inside their home. We have also assumed that those protected inside the residence would be able to evacuate safely from their residence should it catch fire from the event. We have assumed that occupants of these residences would be outside their homes, exposed to torch fire effects, 10% of the time (roughly 17 hours per week).

Anticipated Individual Impacts

In the following paragraphs, the impacts (e.g. serious injuries and fatalities) will be evaluated as they relate to an individual for each of the project components.

16-Inch Transmission Pipeline

There are two existing residences within 200 feet of the proposed transmission pipeline that could be affected by fires. One home is within approximately 60 feet from the pipeline; the other is roughly 100 feet from the line. The lengths of pipeline that could impact the public are summarized below, for each of the identified conditions:

- **Flash Fire, Full Bore Release.** These impacts can be significant within 169 feet of the pipeline. There are 588 feet of the line that could affect these residences.
- **Flash Fire, 1" Diameter Release.** These impacts can be significant within 31 feet of the pipeline. There are no homes located within this distance.
- **Torch Fire, Full Bore Release.** These impacts can be significant within 115 feet of the pipeline. There are 250 feet of the line that could affect these residences.
- **Flash Fire, 1" Diameter Release.** These impacts can be significant within 97 feet of the pipeline. There are 152 feet of line that could affect this residence.

Approximately 2,500 feet (0.47 mile) of the line is within 169 feet of Shiloh Road. (169 feet is the maximum distance from a release that is expected to cause a significant impact.) For this portion of the project, we have assumed an average of one vehicle trip every 15 minutes (4 trips per hour), at 30 mph. This results in a conditional probability of exposure of 0.06. (A traffic study has not been performed to substantiate this assumption.)

The results of the individual risk analyses are shown below. As indicated, the individual risk of fatality is 3.66×10^{-7}. This represents a one in almost three million (1:2,730,000) likelihood of an individual fatality, which is less that the generally accepted significance criteria of 1 in one million (1:1,000,000). As a result, the individual risk from this project component is not considered significant.

Table Ap.4.4-9. Individual Risk Summary – 16-Inch-Diameter Transmission Pipeline

Release	Baseline Probability of Reportable Release	Affected Pipeline Length (miles)	Probability of Occupancy	Conditional Probability of Event	Probability of Serious Injury or Fatality to Exposed Individual	Annual Risk of Individual Serious Injury or Fatality
1-Inch-Diameter Torch Fire Residences	3.90e-04	0.03	0.10	0.0503	0.15	8.82e-09
1-Inch-Diameter Flash Fire Residences	3.90e-04	0.00	0.10	0.0168	1.00	0.00e+00
1-Inch-Diameter Torch Fire Shiloh Road	3.90e-04	0.47	0.06	0.0503	0.15	8.29e-08
1-Inch-Diameter Flash Fire Shiloh Road	3.90e-04	0.47	0.06	0.0168	1.00	1.84e-07
Rupture Torch Fire Residences	3.90e-04	0.05	0.10	0.0128	0.15	3.73e-09
Rupture Flash Fire Residences	3.90e-04	0.11	0.10	0.0043	1.00	1.82e-08
Rupture Torch Fire Shiloh Road	3.90e-04	0.47	0.06	0.0128	0.15	2.10e-08
Rupture Flash Fire Shiloh Road	3.90e-04	0.47	0.06	0.0043	1.00	4.67e-08
1-Inch-Diameter Explosion Residences	3.90e-04	0.00	0.75	0.0450	0.10	0.00e+00
1-Inch-Diameter Explosion Shiloh Road	3.90e-04	0.00	0.06	0.0450	0.10	0.00e+00
Rupture Explosion Residences	3.90e-04	0.00	0.75	0.0110	0.10	0.00e+00
Rupture Explosion Shiloh Road	3.90e-04	0.00	0.06	0.0110	0.10	0.00e+00
Total						3.66e-07

12-Inch Flow Pipeline

As noted earlier, the explosion levels resulting from an unanticipated release are not large enough to result in serious injury or fatality. In addition, there are no residences or sensitive receptors within the distances impacted by fires along this pipeline. As a result, there are no significant risks to public safety posed by this pipeline segment.

4-Inch Temporary Pipeline

As noted earlier, the explosion levels resulting from an unanticipated release are not large enough to result in serious injury or fatality. In addition, there are no residences or sensitive receptors within the distances impacted by fires along this pipeline. As a result, there are no significant risks to public safety posed by this pipeline segment.

Storage Wells

The reservoir will be operated at up to 1,450 psig. Although rare, natural gas releases from storage injection/withdrawal wells do occur. For example, on August 19-26, 2004, there was a well head incident at Duke Energy's Moss Bluff Storage Facility, in Liberty County, Texas that resulted in an uncontrolled gas release. The uncontrolled gas release continued for six and one-half days, releasing approximately 6 billion SCF of gas from the salt dome. Flames reportedly extended one hundred feet into the air, lighting the night sky; the illumination was visible for miles.

The fire eventually self extinguished and on August 26th of that year the installation of a blowout prevention valve was completed. This event was caused by a breach in the 8-inch-diameter well string, 3,724 feet below grade. After a series of events, the entire wellhead assembly separated from the casings, due to the extreme radiant heat. 300 people were evacuated from the surrounding area. But there were no injuries or fatalities.

Throughout the event, the fire remained above ground. Due to the pressure within the reservoir and the below grade mixture being above the upper flammable limit, the fire was not able to migrate below grade.

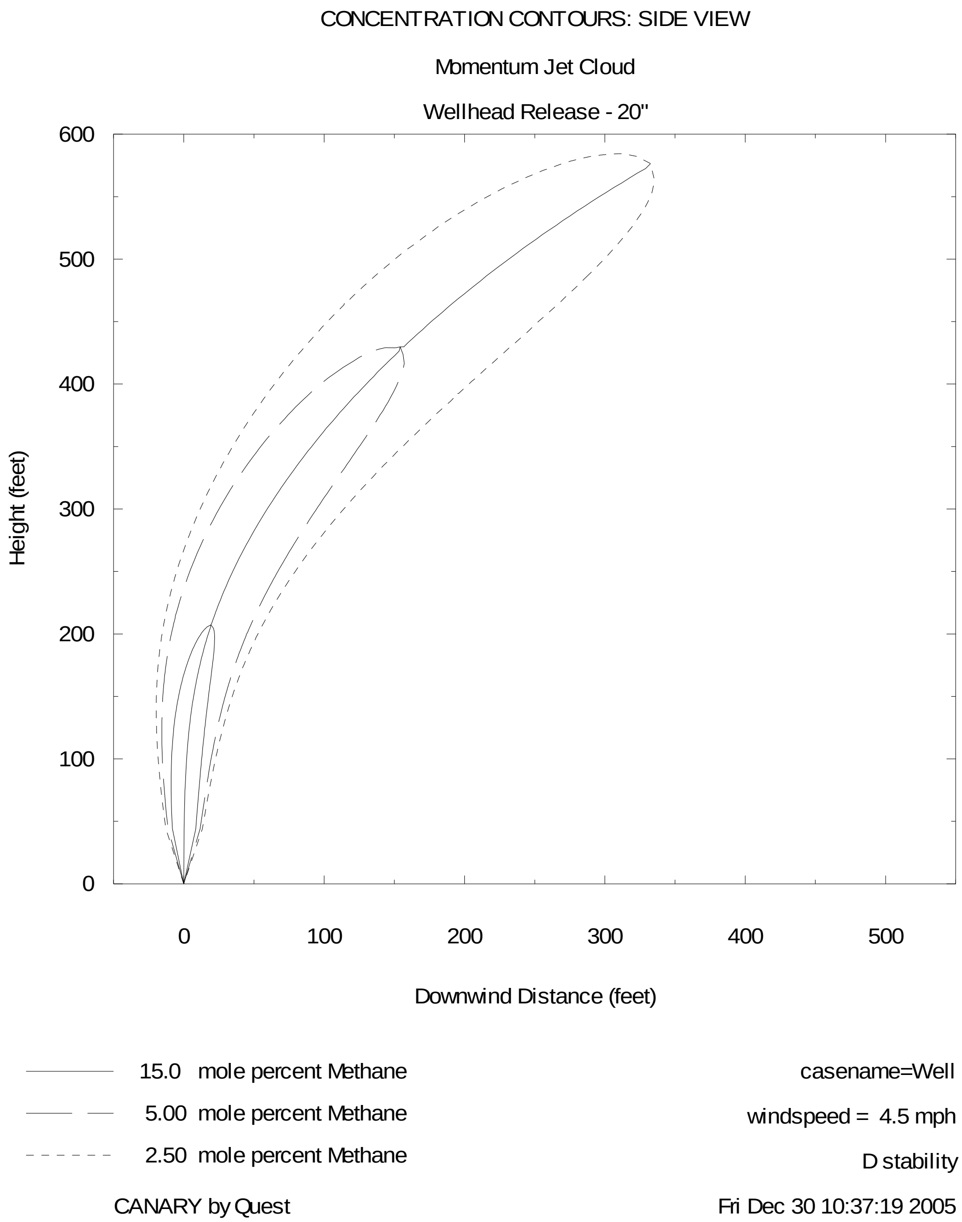
The potential impacts from a similar well head failure have been modeled. We have assumed the complete rupture of a 20" casing. (The actual casing size is unknown.) We have also made the following assumptions:

- Release Duration – 10 Days
- Reservoir Volume – 13 Billion SCF
- Reservoir Pressure – 1,450 psig
- Reservoir Fill Rate – 50 MMSCFD
- Duration of Fill Prior to Pipeline Shut-Down – 120 Minutes
- Diameter of Rupture – 20-inches
- Angle of Release – Vertical

Using these data, we found a peak overpressure resulting from an explosion of 0.44 psig. Similar to the pipeline explosion results, the overpressure level is low, due to the open, unconfined surroundings. Overpressures of 0.40 and 0.20 psig extended 273 and 560 feet from the release respectively.

The fire analysis indicated that the flash fire cloud (LFL) would extend up to 154 feet from the site laterally. However, the flash fire cloud would extend almost 430 feet into the air. The torch fire would result in radiant heat levels of 3,500, 1,600, and 440 Btu/hr-ft^2 at distances of 118, 148, and 229 feet respectively, downwind of the release. For reference, the vertical profile of the flash fire cloud is shown in Figure Ap.4.4-1 below. The combustible portion of the vapor cloud is located between the 5.0 (LFL) and 15.0 (UFL) mole percent of methane.

Figure Ap.4.4-1. Well Fire Vapor Cloud



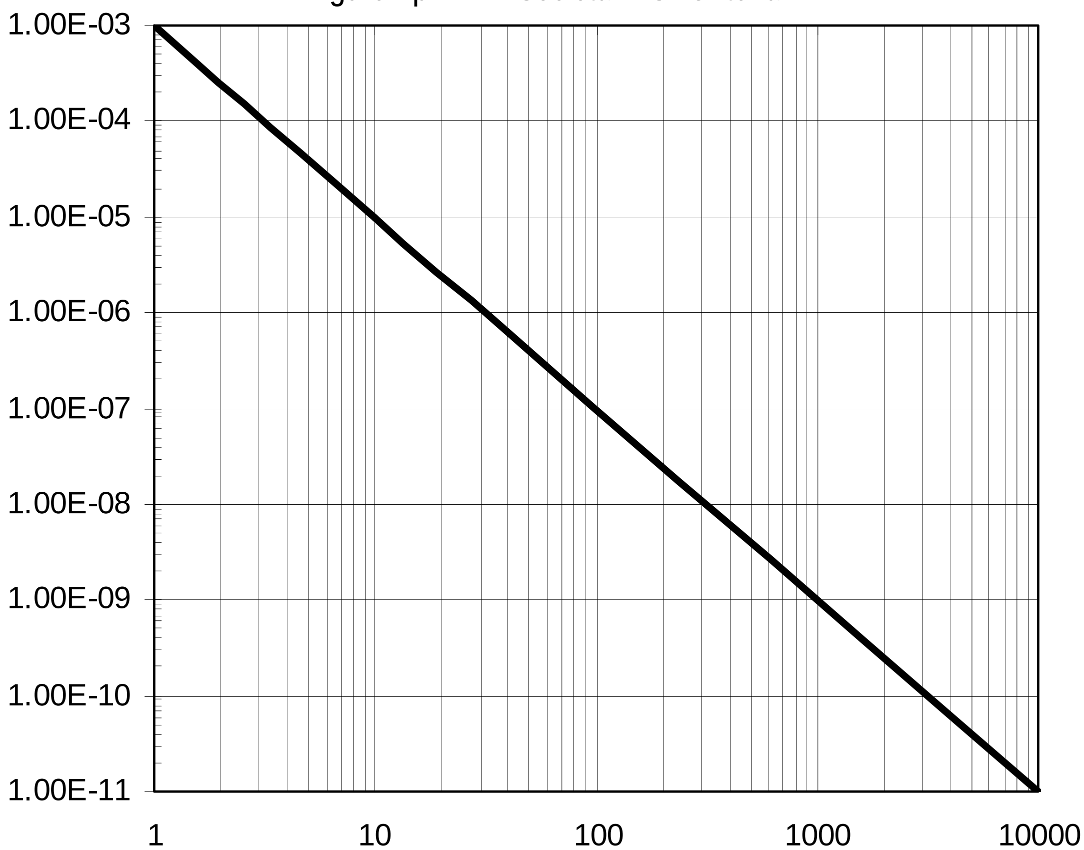
Similar to the 12-inch gathering and the 4-inch-diameter flow line, the proposed wells are located far enough from existing residences that impacts to public safety are not anticipated.

Anticipated Societal Impacts

Societal risk is the probability that a specified number of people will be affected by a given event. The accepted number of casualties is relatively high for lower probability events and much lower for more probable events. However, the acceptable values for societal risk vary greatly. Unfortunately, there are no prescribed societal risk guidelines for the United States, nor the State of California.

For the siting of new schools, the California Department of Education (CDE) conservatively considers a level of significance those events which result in one (1) fatality with an annual probability of 1.0×10^{-5} (1:100,000) or less; for events which result in thirty (30) fatalities, the acceptable annual probability increases to 1.0×10^{-8} (1:100,000,000) or less. In contract, the United Kingdom, considers a level of significance those events which result in 100 fatalities, with an annual probability of 1.0×10^{-5} (1:100,000) or less; this is 100 times the number of fatalities for the siting of California schools, using the same recurrence criteria. The Committee for the Prevention of Disasters uses the criteria as shown below. This data is the same as the criteria used in the Netherlands and is the most conservative of the published data for Western Europe. These criteria have been used to evaluate societal risk herein.

Figure Ap.4.4-2. Societal Risk Criteria



Notes: This societal risk criterion is based on the Committee for the Prevention of Disasters and is used in the Netherlands. This is the most conservative criteria used in Western Europe.

16-Inch-Diameter Transmission Pipeline

The results of the societal risk analysis are presented in Table Ap.4.4-10 and Ap.4.4-11 below for the 16-inch-diameter pipeline segment. For example, the probability of a pipeline rupture resulting in a flash fire along Shiloh Road is 4.67×10^{-8} (1:21,000,000). For this event, we have assumed that 2 individuals (traveling in an auto) would likely be exposed, with a 100% possibility of serious injury or fatality. This results in a potential for 2.0 site casualties. Based on the anticipated frequency, roughly 150 casualties would be allowed before this risk was considered significant (reference Figure Ap.4.4-2). As indicated in Table Ap.4.4-11, the ratio of site casualties to the societal risk criteria for this case is 0.0133. Since this value is less than 1.0, this event is not considered significant, using the stated societal risk criteria, since the probability of seriously injuring 2 people is less than the criteria threshold.

Table Ap.4.4-10. Societal Risk Exposure Probability

Release	Baseline Probability of Reportable Release	Affected Pipeline Length (miles)	Probability of Occupancy	Conditional Probability of Event	Exposure Probability
1-Inch-Diameter Torch Fire Residences	3.90e-04	0.03	0.10	0.0503	5.88e-08
1-Inch-Diameter Flash Fire Residences	3.90e-04	0.00	0.10	0.0168	0.00e+00
1-Inch-Diameter Torch Fire Shiloh Road	3.90e-04	0.47	0.06	0.0503	5.53e-07
1-Inch-Diameter Flash Fire Shiloh Road	3.90e-04	0.47	0.06	0.0168	1.84e-07
Rupture Torch Fire Residences	3.90e-04	0.05	0.10	0.0128	2.49e-08
Rupture Flash Fire Residences	3.90e-04	0.11	0.10	0.0043	1.82e-08
Rupture Torch Fire Shiloh Road	3.90e-04	0.47	0.06	0.0128	1.40e-07
Rupture Flash Fire Shiloh Road	3.90e-04	0.47	0.06	0.0043	4.67e-08
1-Inch-Diameter Explosion Residences	3.90e-04	0.00	0.75	0.0450	0.00e+00
1-Inch-Diameter Explosion Shiloh Road	3.90e-04	0.00	0.06	0.0450	0.00e+00
Full Bore Explosion Residences	3.90e-04	0.00	0.75	0.0110	0.00e+00
Full Bore Explosion Shiloh Road	3.90e-04	0.00	0.06	0.0110	0.00e+00

Table Ap.4.4-11. Societal Risk Significance

Release	Exposure Probability	Probability of Serious Injury or Fatality	Population (Assumes 4 persons per residence and 2 per vehicle)	Number of Site Casualties (SC)	Societal Risk Criteria (SRC)	SC/SRC Note 1
1-Inch-Diameter Torch Fire Residences	5.88e-08	0.15	4	0.6	110	0.0055
1-Inch-Diameter Flash Fire Residences	0.00e+00	1.00	4	4.0	NA	NA
1-Inch-Diameter Torch Fire Shiloh Road	5.53e-07	0.15	2	0.3	40	0.0075
1-Inch-Diameter Flash Fire Shiloh Road	1.84e-07	1.00	2	2.0	75	0.0267
Rupture Torch Fire Residences	2.49e-08	0.15	4	0.6	200	0.0030
Rupture Flash Fire Residences	1.82e-08	1.00	4	4.0	200	0.0200
Rupture Torch Fire Shiloh Road	1.40e-07	0.15	2	0.3	80	0.0038
Rupture Flash Fire Shiloh Road	4.67e-08	1.00	2	2.0	150	0.0133
1-Inch-Diameter Explosion Residences	0.00e+00	0.00	4	0.0	NA	NA
1-Inch-Diameter Explosion Shiloh Road	0.00e+00	0.00	4	0.0	NA	NA
Full Bore Explosion Residences	0.00e+00	0.00	2	0.0	NA	NA
Full Bore Explosion Shiloh Road	0.00e+00	0.00	2	0.0	NA	NA

Note: Since the SC/SRC is less than 1.0, the societal risk is not considered significant.

12-inch Flow Pipeline

As noted earlier, the explosion levels resulting from an unanticipated release are not large enough to result in serious injury or fatality. In addition, there are no residences or sensitive receptors within the distances impacted by fires along this pipeline. As a result, there are no significant societal risks to public safety posed by this pipeline segment.

4-inch Temporary Pipeline

As noted earlier, the explosion levels resulting from an unanticipated release are not large enough to result in serious injury or fatality. In addition, there are no residences or sensitive receptors within the distances impacted by fires along this pipeline. As a result, there are no significant societal risks to public safety posed by this pipeline segment.

Societal Impacts from Wellheads

Similar to the 12-inch gathering and the 4-inch-diameter flow line, the proposed wells are located far enough from existing residences and public areas that societal impacts are not anticipated.

Ap.4.5 Environmental Impacts and Mitigation Measures

b. Would the project create a significant hazard to the public or the environment through reasonably foreseeable upset and accident conditions involving the release of hazardous materials into the environment?

LESS THAN SIGNIFICANT IMPACT WITH MITIGATION INCORPORATED. If the project components are designed and constructed in accordance with applicable LORS, the project will pose a less than significant impact. However, the primary regulation applicable to this project, 49 CFR 192, does not require an independent, third party review of the design, nor any oversight of the construction inspection for the major project components. Third party design reviews and construction inspections are employed in many other industries to help protect the public safety, public health, the environment, property, and the public welfare by ensuring compliance with applicable LORS. For example, the widely adopted Uniform Building Code gives local building officials the responsibility for independent design reviews (plan checks) and construction observation of buildings and other structures prior to occupancy.

Although the Solano County Public Works Department may conduct a plan check and inspection of some project components (e.g., compressor building), they may not have the expertise to oversee the engineering and construction of the process facilities and pipeline components. The Public Utilities Commission has the responsibility for enforcing the requirements of 49 CFR 192 for these intrastate pipeline facilities. To ensure that these regulations are complied with during the design and construction of the proposed facilities, we recommend the following mitigation measure:

Proposed Mitigation: *The CPUC shall conduct, or cause to be conducted, an independent, third party design review of the Applicant's construction drawings and specifications and shall monitor and observe construction to ensure compliance with all applicable LORS. The applicant shall make payments to the CPUC for these design review, plan check and construction inspection services. These design review and construction observation services shall not in any way relieve the applicant of its responsibility and liability for the design, construction, operation, maintenance, and emergency response for these facilities.*

The CPUC may wish to consider the California Energy Commission's (CEC's) model for conducting these reviews for new electrical power plants. These plants have many of the same components as the proposed project (e.g. pipelines, compressors, electrical systems, buildings, etc.). In most instances, the local building departments do not have the necessary resources, nor expertise, to independently verify the design of the process facilities. In these situations, the CEC retains an independent third party to act as their Deputy Chief Building Official. This third party conducts the plan checks of the applicant's construction drawings and performs the construction inspections to ensure compliance with applicable LORS.