The tanks and piping that are near potential traffic hazards will be protected from vehicle impact by traffic barriers.

After removing from consideration those chemicals that pose no risk of offsite impact in Steps 1 and 2, staff continued with Steps 3, 4, and 5 to review the remaining hazardous materials: sodium hypochlorite, sodium hydroxide, natural gas, sulfuric acid and aqueous ammonia.

Large Quantity Hazardous Materials

Sulfuric acid, sodium hydroxide and sodium hypochlorite will be stored on-site but do not pose a risk of offsite impacts because they have relatively low vapor pressures and thus the impact of spills would be confined to the site. Staff found no hazard would be posed to the public due to the extremely low volatility of these solutions. However, in order to protect against risk of volatilizing sulfuric acid in a fire, staff proposes Condition of Certification **HAZ-5** that will require that no combustible or flammable material is stored within 50 feet of the sulfuric acid tank.

Natural Gas

Natural gas poses a fire and/or explosion risk as a result of its flammability. Natural gas is composed of mostly methane, but also contains ethane, propane, nitrogen, butane, isobutane and isopentane. It is colorless, odorless, and tasteless and is lighter than air. Natural gas can cause asphyxiation when methane is ninety percent in concentration. Methane is flammable when mixed in air at concentrations of 5 to 14 percent, which is also the detonation range. Natural gas, therefore, poses a risk of fire and/or explosion if a release were to occur. However, it should be noted that, due to its tendency to disperse rapidly (Lees 1998), natural gas is less likely to cause explosions than many other fuel gases, such as propane or liquefied petroleum gas.

While natural gas will be used in significant quantities, it will not be stored on-site. The risk of a fire and/or explosion on-site can be reduced to insignificant levels through adherence to applicable codes and development and implementation of effective safety management practices. In particular, gas explosions can occur in the heat recovery steam generator (HRSG) and during start-up. The National Fire Protection Association (NFPA 85A) requires 1) the use of double block and bleed valves for gas shut-off; 2) automated combustion controls; and 3) burner management systems. These measures will significantly reduce the likelihood of an explosion in gas-fired equipment. Additionally, start-up procedures would require air purging of the gas turbines prior to start-up, thus precluding the presence of an explosive mixture. The safety management plan proposed by the applicant would address the handling and use of natural gas and significantly reduce the potential for equipment failure due to improper maintenance or human error.

The proposed facility would require the upgrade of a bottleneck in an existing SDG&E pipeline located about one mile northwest of the proposed facility. This 2,600 foot, 16-inch, pipeline upgrade would be constructed, owned and operated by SDG&E. The design of the natural gas pipeline is governed by the laws and regulations discussed above. These LORS require use of high quality arc welding techniques by certified welders and inspection of welds. Many failures of older natural gas lines have been associated with poor quality welds or corrosion. Current codes address corrosion failures by requiring use of corrosion resistant coatings and cathodic corrosion protection. Another major cause of pipeline failure is damage resulting from excavation activities near pipelines. Current codes address this mode of failure by requiring clear marking of the pipeline route. An additional mode of failure particularly relevant to the project area is damage caused by earthquake. Existing codes also address seismic hazard in design criteria (as discussed below). Evaluation of pipeline performance in recent earthquakes indicates that pipelines designed to modern codes perform well in seismic events while older lines frequently fail. SDG&E must design and inspect the pipeline in accordance with California Public Utilities Commission (CPUC) General Order 112E and Federal Pipeline Safety Regulations, 49 CFR 192 requirements. Staff believes that these regulatory requirements are sufficient to reduce the risk of accidental release from the pipeline to insignificant levels.

Failures of gas pipelines, according to data from the U.S. Department of Transportation (the National Transportation Safety Board) from the period 1984 - 1991, occur as a result of pipeline corrosion, pipeline construction or materials defects, rupture by heavy equipment excavating in the area such as bulldozers and backhoes, weather effects, and earthquakes. Given the gas line failures which occurred in the Marina District of San Francisco during the 1989 Loma Prieta earthquake, the January 1994 Northridge earthquake in Southern California, and the January 1995 gas pipeline failures in Kobe, Japan, as well as the January 19, 1995 gas explosion in San Francisco, the safety of the gas pipeline is of paramount importance. However, it must be noted that those pipelines which failed were older and not manufactured nor installed to modern code requirements. The February 2001 Nisqually Earthquake near Olympia, Washington, caused no damage to natural gas mains and there was only one reported gas line leak due to a separation of a service line going into a mobile home park.

SDG&E will construct an upgrade of 2600 feet of 16-inch pipeline upgrading a bottleneck in their pipeline located about one mile northwest of the facility. If release of gas occurs as a result of pipe, valve, or other mechanical failure or external forces, significant quantities of compressed natural gas could be released rapidly. Such a release can result in a significant fire and/or explosion hazard, which could cause loss of life and/or significant property damage in the vicinity of the pipeline route. However, the probability of such an event is extremely low if the pipeline is constructed according to present standards.

According to DOT statistics, the frequency of reportable incidents is about 0.25 for all pipeline incidents per 1,000 miles per year or 2.5×10^{-4} incidents per mile per year. DOT has also evaluated and categorized the major causes of pipeline failure. The four major causes of accidental releases from natural gas pipelines are: outside forces-43 percent, corrosion-18 percent, construction/material defects-13 percent, and other-26 percent.

Outside forces are the primary causes of incidents. Damage from outside forces includes damage caused by use of heavy mechanical equipment near pipelines (e.g., bulldozers and backhoes used in excavation activities), weather effects, vandalism, and earthquake-caused rupture as seen in the Marina District of San Francisco during the 1989 Loma Prieta Quake and in Kobe, Japan in January 1995. The fourth category, “Other” includes equipment component failure, compressor station failures, operator errors and sabotage. The average annual service incident frequency for natural gas transmission systems varies with age, the diameter of the pipeline, and the amount of corrosion.

Older pipelines have a significantly higher frequency of incidents. This results from the lack of corrosion protection and use of less corrosion resistant materials compared to modern pipelines, limited use of modern inspection techniques, and higher frequency of incidents involving outside forces. The increased incident rate due to outside forces is the result of the use of a larger number of smaller diameter pipelines in older systems, which are generally more easily damaged, and uncertainty regarding the locations of older pipelines.

In the United States, extensive federal and state pipeline codes and safety enforcement minimize the risk of severe accidents related to natural gas pipelines. In November 2000, the DOT Office of Pipeline Safety proposed a program requiring the preparation of risk management plans for gas pipelines throughout the United States. These risk management plans will include the use of diagnostic techniques to detect internal and external corrosion or cracks in pipelines and to perform preventive maintenance. The project owner will be required to develop and implement these plans if the proposal is promulgated as a regulation. As of this date, no regulations have been promulgated.

The following safety features will be incorporated into the design and operation of the natural gas pipeline (as required by current federal and state codes): (1) while the pipeline will be designed, constructed, and tested to carry natural gas at a certain pressure, the working pressure will be less than the design pressure; (2) butt welds will be X-rayed and the pipeline will be tested with water prior to the introduction of natural gas into the line; (3) the pipeline will be surveyed for leakage annually (4) the pipeline will be marked to prevent rupture by heavy equipment excavating in the area; and (5) valves at the meter will be installed to isolate the line if a leak occurs. These requirements will be administered by the federal government and the CPUC.

Aqueous Ammonia

Aqueous ammonia and natural gas are the only hazardous materials that may pose a risk of offsite impacts. Aqueous ammonia will be used in controlling the emission of oxides of nitrogen (NO_x) from the combustion of natural gas in the facility. The accidental release of aqueous ammonia without proper mitigation can result in very high down-wind concentrations of ammonia gas. One storage tank will be used to store the 19.5 percent aqueous ammonia with a maximum capacity of 20,000 gallons.

The use of aqueous ammonia can result in the formation and release of toxic gases in the event of a spill even without interaction with other chemicals. This is a result of its moderate vapor pressure and the large amounts of aqueous ammonia, which will be used and stored on-site. However, as with aqueous hypochlorite, the use of aqueous ammonia instead of the much more hazardous anhydrous ammonia (i.e. ammonia that is not diluted with water) poses far less risk.

To assess the potential impacts associated with an accidental release of ammonia, staff typically evaluates where four “bench mark” exposure levels of ammonia gas occur offsite. These include: 1) the lowest concentration posing a risk of lethality, 2,000 ppm; 2) the Immediately Dangerous to Life and Health (IDLH) level of 300 ppm; 3) the Emergency Response Planning Guideline (ERPG) level 2 of 150 ppm (recently changed from the 200 ppm value), which is also the RMP level 1 criterion used by EPA and most administering agencies in California; and 4) the level considered by the Energy Commission staff to be