Long-Term Viability of Underground Natural Gas Storage in California

An Independent Review of Scientific and Technical Information

Chapter 1, Section 1.2

Failure modes, likelihood, and consequences

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California Council on Science and Technology

December 2017

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Acknowledgments

This report has been prepared by the California Council on Science and Technology (CCST) with funding from the California Public Utilities Commission.

 ISBN Number: 978-1-930117-86-0 Long-Term Viability of Underground Natural Gas Storage in California: An Independent Review of Scientific and Technical Information

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1.2 FAILURE MODES, LIKELIHOOD, AND CONSEQUENCES

1.2.1 Abstract

We review the main failure modes, likelihood of failure, and the consequences of failure of UGS in California. For the purposes of this section, failure is most commonly loss-of-containment (LOC), but it can also be damage to a well or other component that affects health and safety, the environment, or facility operations without LOC. The reason LOC is the main focus is that UGS involves containing through multiple repeated operations (compression, injection, storage, withdrawal, decompression, processing, utilization) of a highly flammable gas at very high pressure. In the subsurface part of UGS, well integrity and reservoir integrity are needed to contain natural gas. Well integrity failures can occur for many reasons, but failure of cement seals and corrosion of casing are two of the main causes of subsurface LOC. Reservoir integrity relies on caprock sealing and lack of transmissive faults, both of which have been known to fail at UGS systems in the past. In the surface part of UGS, failure can occur by damage to pipelines, valves, seals, and many other components relied upon to contain high-pressure gas in the aboveground infrastructure of UGS facilities. Some California UGS facilities identified here are located in regions with particular hazards, among which are seismic, landslide, flood, tsunami, and wildfire hazards, all of which are external events that can affect UGS infrastructure. Human and organizational factors are widely cited as a cause of incidents at industrial facilities such as UGS sites.

The likelihood of UGS facility failure can be qualitatively estimated by the record of reported incidents in California. This record suggests that an incident of severity significant enough to have been reported will occur on average 4.1 times per year somewhere in California, and most of these incidents will be caused by well integrity failures. But these statistics must be used cautiously, because the overall number of events is relatively small, and reporting of incidents has not been regulated or standardized. The consequences of LOC incidents can be catastrophic, as in the case of large releases such as occur during well blowouts or flowline rupture with ignition, or they can occur without impacts to safety but with potential long-term impact to environment, as in the case of chronic low-flow-rate leakage of methane in the context of its role as a greenhouse gas. Dispersion of any emitted gas will occur by air entrainment and surface winds. The dispersion of leaked natural gas and resulting downwind concentrations relevant to ignition and explosivity can be modeled very accurately, provided local wind and leakage flow rate data are available. Analysis of dispersion of leaked natural gas suggests that the footprint of methane concentrations between the lower and upper flammability limits can be expected to exceed the size of the clustered surface infrastructure (e.g., a compressor pad, gas-processing facility pad, or the clustered wellheads on pads of multiple deviated wells) for large but not impossible leakage fluxes, meaning that the surface infrastructure is vulnerable to explosion hazard. Subsurface leakage of natural gas, e.g., by annular overpressurization, can allow natural gas to flow into underground sources of drinking water (USDW), typically at much shallower levels than the storage reservoir. There are recorded incidents of natural gas leaking to surface that must have encountered USDW, although specifics of the impacts have not been

assessed to our knowledge. In general,
we believe adherence to the new regulations proposed by California Division of Oil, Gas and Geothermal Resources (DOGGR) will strongly reduce the likelihood of well integrity failures.

1.2.2 Introduction

This section reviews the failure modes, likelihood of failure, and the consequences of failure of UGS in California. Using a combination of literature review of UGS worldwide, and knowledge of California's specific UGS system characteristics as reviewed in Section 1.1, we can develop an understanding of the potential impacts of UGS in California and their likelihood. We do not carry out a formal risk assessment for any site or any risk category. Instead, we discuss the likelihood and consequences of LOC and other kinds of incidents. Actual health and safety hazards arising from the various failure scenarios are discussed in Section 1.4. In this section, we will do the following:

1. Discuss the ways that UGS components and systems most commonly fail
2. Describe the interactions between components in failure scenarios
3. Review the estimation of UGS failure likelihood in California
4. Review the consequences of UGS failure scenarios in terms of dispersion patterns
5. Review the impacts of failures on the UGS infrastructure (e.g., fire and explosion)
6. Review impacts of failures on resources such as USDW

1.2.3 Failure Modes

1.2.3.1 Introduction

There are three fundamental types of UGS failure: (1) facility cannot accept gas from the transmission pipeline for injection; (2) facility cannot deliver high-quality gas back to the pipeline; or (3) facility fails to contain gas. There are many different causes for these three potential failure types. For example, inoperable or malfunctioning equipment, including flowlines, may prevent the facility from receiving gas from the pipeline. Similarly, malfunctioning gas processing equipment may prevent the facility from delivering high-quality gas back to the transmission pipeline. Moreover, the well or the formation may be damaged and not functioning as required for gas injection and/or production. Failure Types 1 and 2 do not necessarily involve a hazard to health, safety, and the environment (HSE). On the other hand, Type 3, loss-of-containment (LOC), involves potentially catastrophic consequences for human health (including loss of life), UGS infrastructure, environmental resources, and surrounding property. In this section, we focus on Type 3 failures and LOC

risk, because it is the largest hazard to HSE and UGS infrastructure. The Type 3 failure can occur by a wide variety of modes, as will be described below.

Prior studies have lumped UGS failures into a single category referred to as *incidents* (Evans, 2009; Folga et al., 2016; Schultz et al., 2017). Folga et al. (2016) use the term *incident* to refer to a broad array of operational dysfunctions, many of which do not shut down the whole facility. The term *incident* is preferable to *accident*, because it is more general and does not imply anything about intent or cause. Some authors add the term *major* (or *severe* or *significant*) as a modifier to the term *incident* (International Energy Agency Greenhouse Gas (IEAGHG), 2006; Folga et al., 2016) and define major incidents as those involving injury/fatality, property damage, site evacuation, or uncontrolled leak, although no thresholds for injury, property damage, or leakage rate are provided. Recently, Evans and Schultz (2017) have introduced the term *occurrence* in place of *incident* to acknowledge that many reports of dysfunction are very minor and do not result in LOC or facility interruption. Evans and Schultz (2017) have also introduced a severity ranking for occurrences. The field of UGS dysfunction cataloging, data analysis, and severity ranking is dynamic at present, and no single agreed-upon terms or severity thresholds have emerged.

Here we use the term *incident* to refer to reported events related to loss-of-containment of natural gas of any magnitude arising for any reason or underlying cause. For example, loss-of-containment could occur from leaks in flowlines, valves, compressors, gas-processing units, wellheads, wells, caprock, and faults. The results of such incidents may be injury or death, e.g., from resulting fires and explosions, or damage to the facility or other property, not to mention loss of stored gas and potential related environmental damage. Because minor incidents are not reported and cataloged for evaluation, we normally use the term *incident* without a modifier. By this usage, the term *incident* will implicitly refer to events related to significant loss-of-containment of stored gas, i.e., significant enough that it warranted reporting.

The term *leakage* also requires definition. As used here, the term *leakage* refers to flow or migration of gas out of the storage system, which includes the surface infrastructure designed to contain the high-pressure gas along with the well and the subsurface reservoir. By this definition, leakage may involve deep casing failures and/or migration of gas out of the reservoir but not necessarily into the atmosphere. This definition follows prior use of the term *leakage* in the area of geologic carbon sequestration (e.g., Oldenburg et al., 2009), in which field leakage to atmosphere is called *surface leakage*.

The term *loss-of-containment (LOC)* is defined here as the unplanned release of stored gas or related fluid into the environment, subsurface or aboveground. As such, the terms leakage and *LOC* are synonymous; there may or may not be loss to atmosphere depending on where the leakage occurs.

1.2.3.2 Origin of High Pressure in UGS

Water wells, along with most oil wells, differ fundamentally from gas wells with respect to the pressure along the length of the well and at the wellhead. Specifically, water wells and oil wells usually need a pump to produce fluid from the well, whereas natural gas flows freely and rapidly if not contained at the wellhead. The reason for this difference is shown by the pressure profiles presented in Figure 1.2-1 (after Smit et al. (2014), Figure 9.6.3). Figure 1.2-1 depicts the relevant profiles of pressure in the subsurface along with a representative gas well accessing a gas reservoir at 2 km (~6,600 ft) depth that is at hydrostatic pressure. As shown, the gas-static pressure in the well does not vary significantly along the length of the well, because methane density averages only about 70 kg/m^3 in the well (at P = 10 MPa (1,450 psi) and 45°C (113°F) at depth of 1 km), which is small relative to water density, which is about 14 times larger. As shown, the gas pressure in the well is higher than the hydrostatic pressure everywhere above the reservoir, and it is higher than the frac gradient (or fracture gradient) and lithostatic pressure above about 500 m (1,600 ft) depth in the well. Therefore, in order to contain the gas in the subsurface and surface systems, the wells and surface infrastructure connected to the wells must be capable of holding this large pressure (~20 MPa =
~2900 psi) relative to the formation pressure at any depth and relative to atmospheric pressure in aboveground infrastructure. In addition, pressure in the well may be even higher during injection.

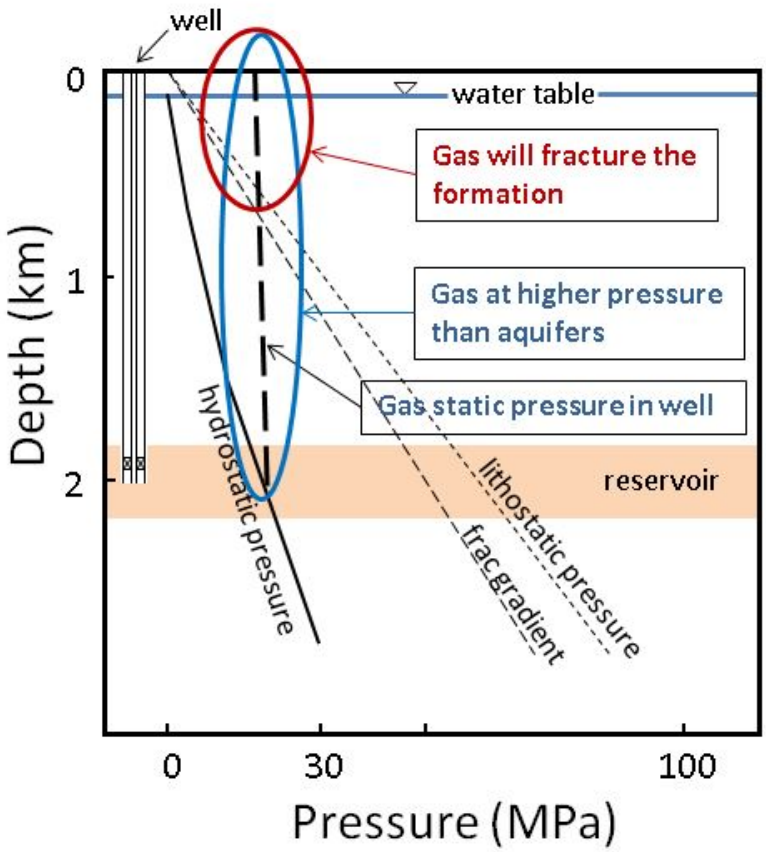


Figure 1.2-1. Sketch of pressure profiles as a function of depth showing that a well filled with natural gas and held at hydrostatic pressure in the gas reservoir must be able to withstand and contain pressure throughout its length as indicated by the gas static pressure profile. The figure shows that in the shallow parts of the well (less than depths of ~500 m shown by red circle), gas pressure may exceed the fracture gradient and lithostatic pressure meaning LOC can fracture the formation. Throughout the length of the well, the gas pressure is higher than hydrostatic pressure (blue circle) meaning LOC can lead to gas entering aquifers.

1.2.3.3 Wells Couple Surface and Subsurface Parts of UGS

Coupling the surface (engineered) and subsurface (wells plus geologic storage system) parts of the UGS system (see Figure 1.0-1) is challenging and creates potential vulnerabilities to storage integrity. These challenges arise from the heterogeneity and incomplete knowledge inherent in subsurface systems. The main component involved in coupling the engineered

and natural systems is the well, which consists of multiple steel casings and (normally) tubing that allows injection and withdrawal of gas and liquids. A primary component of a well in a gas storage reservoir is the cement that seals the gaps between the outermost well casing and the rock comprising the sides of the wellbore.

It is notable that UGS wells in California and elsewhere in the U.S. as a rule carry out production and injection not only through tubing, as in nearly all other injection and production wells (e.g., in oil and gas, and in deep disposal operations), but also through the casing, or so-called A-annulus. This aberration in standard practice is allowed in the UGS industry because UGS is excluded from the U.S. EPA's Underground Injection Control (UIC) program, which requires tubing and packer (no A-annulus injection or production). The UIC program arose from the Safe Drinking Water Act (SDWA), which authorizes the U.S. EPA to oversee states, municipalities, and water suppliers in maintaining standards for drinking water quality. In addition, the SDWA establishes requirements and provisions for regulation of fluid injection into the subsurface. The U.S. EPA administers the UIC program to regulate subsurface fluid injection. Most fluid injected underground consists of oil-production-related wastewater, but a wide variety of fluid-injection operations are regulated under the UIC (Clark and Veil, 2009). Notably, injection wells involving any hydrocarbon substance that is a gas at standard conditions of 1 bar and 15°C (0.987 atm, 60°F) are exempted from UIC. Methane clearly falls into this category, which leads to the fact that UGS wells in the U.S. are not regulated under UIC and therefore UGS wells are not required to have barriers conforming to the two-point failure standard (see Figure 1.2-2 and related discussion below).

We note in passing that CO_2 is also a gas at standard pressure and temperature, but it is not a hydrocarbon, and therefore geologic carbon sequestration wells are regulated by the U.S. EPA under the UIC program (U.S. EPA, 2012; IEAGHG, 2006).

We present in Figure 1.2-2 a sketch of a UGS well based loosely on the Standard-Sesnon-25 (SS-25) well at Aliso Canyon that sustained a blowout in 2015 (e.g., Interagency Task Force on Natural Gas Storage Safety, 2016, p. 18 ff). As shown, the well is constructed using an 11 ¾-in surface casing cemented to ~1,000 ft, surrounding a 7-in production casing that extends to the reservoir. Cement also is present from the reservoir extending through the caprock. The purpose of the cement along the outside of the casing through the caprock is to seal the reservoir from formations above along the well. As discussed above, the cement seal through the caprock must be able to withstand the large pressures developed in the reservoir. Often (particularly in older wells), the cement sealing the well through the caprock does not extend to surface, leaving several thousand feet of uncemented casing. The gap outside of casing in this case may be filled with formation water or drilling mud. Regardless, this gap cannot be considered a barrier for gas containment and can act instead like a leakage pathway.

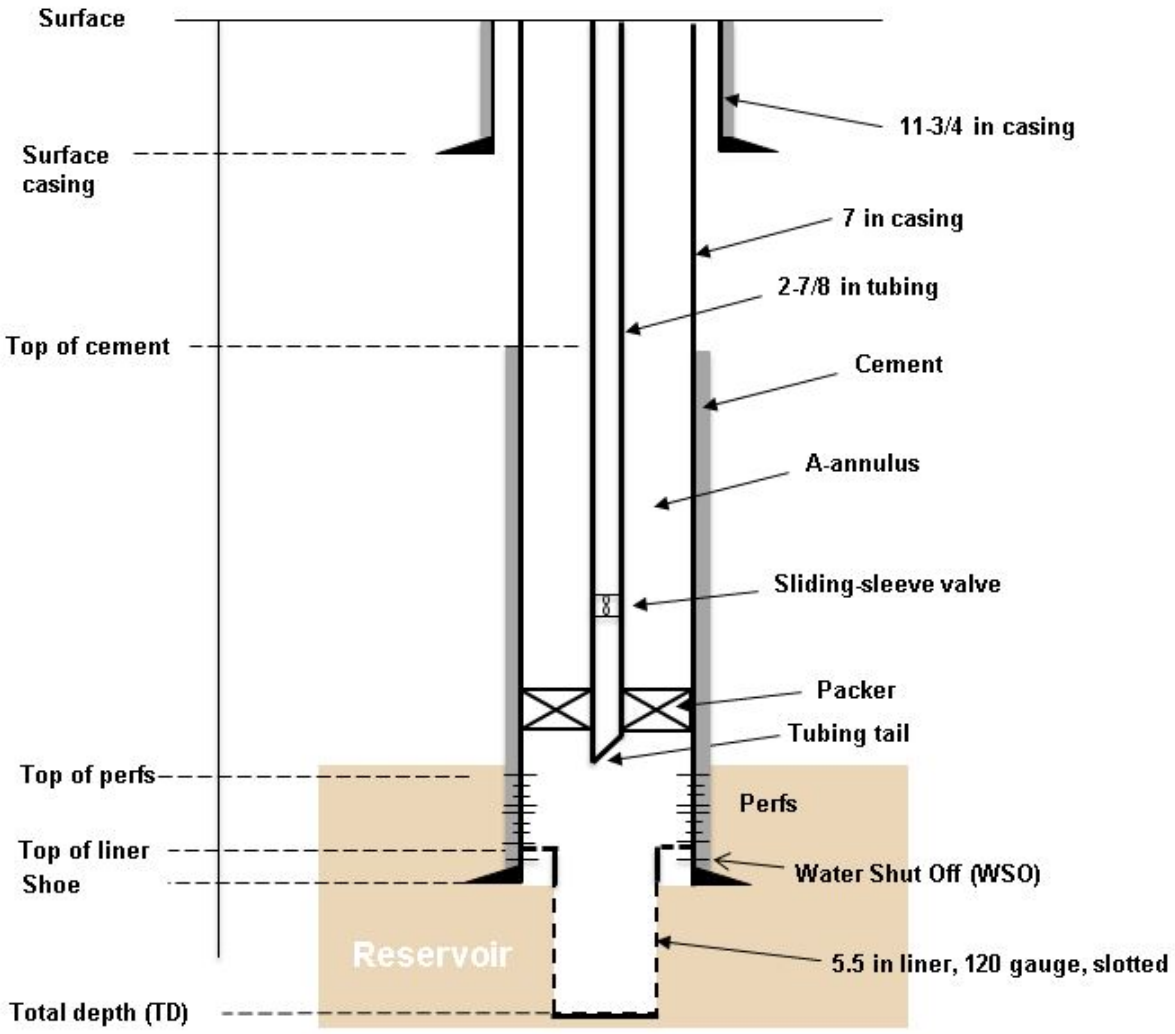


Figure 1.2-2. Simplified sketch (not to scale) of a UGS well based loosely on the Aliso Canyon SS-25 well. Perfs (short for perforations) are the holes or slots that serve to connect the well to the reservoir fluids.

Although the well depicted in Figure 1.2-2 has a tubing and packer, the tubing in this well is connected to the A-annulus by open ports. In the case of the SS-25 well, these ports were the remnants of a dismantled sliding sleeve valve. California UGS wells commonly utilize the A-annulus for production in order to maximize deliverability, i.e., the entire A-annulus is used as a flow zone for production and injection. As shown in Section 1.1, Figure 1.1-10, nearly every UGS well in California has equal pressure in the tubing and A-annulus, indicating the two parts of the well are connected, resulting in high pressure in the A-annulus.

The use of the A-annulus for injection and production has been standard practice in UGS, even though it allows high-pressure gas to contact the casing along the entire length of the well, including regions of the well with no cement outside of casing. This configuration allows additional strain on the casing, because there is only water or mud in the gap between casing and rock to counteract the high-pressure gas inside the casing. Overall, the connection of tubing to A-annulus, and/or use of the A-annulus for gas production and injection, creates a configuration that allows for what is referred to as a single-point failure, because any failure of the casing integrity can lead to high-pressure gas leakage. Normally, oil and gas wells and injection wells regulated under UIC are not constructed nor configured to operate in this way. Instead, normal oil and gas wells and injection wells only inject or produce high-pressure fluids through the tubing, reserving the A-annulus to serve as a secondary volume available for monitoring uses that is confined by the casing, which serves as the secondary barrier in case the packer or tubing fail. This standard injection and production well configuration, used throughout the oil and gas and the deep-fluid injection industry, as regulated by UIC, creates a two-point failure configuration. In other words, in order for the well to suffer LOC (lose integrity) by tubing, packer, or casing failure, more than one of these components would have to fail at the same time. Two-point failure configurations are much safer than single-point failure configurations. The exclusion of UGS from UIC as discussed above allows reliance on single-point failure configurations (e.g., Michanowicz et al., 2017). Under the emergency regulations imposed by DOGGR on January 15, 2016, single-point failure configurations were effectively outlawed. Additional permanent UGS regulations currently under consideration will take effect January 1, 2018 (see Section 1.6).

1.2.3.4 Loss-of-containment from the Subsurface System

Stripped to the essentials, well integrity relies on cement, steel, and pressure control, e.g., through use of heavy drilling mud and kill fluids during drilling and other well work-over operations. The purpose of gas wells in the context of this study is to convey fluids to and from the reservoir without allowing (a) gas from the reservoir to leak out anywhere along the length of the well, and (b) to prevent fluids from intermediate levels along the length of the well from flowing up or down along the well. Well construction is carried out to achieve these goals through the use of (multiple) steel casings and cement that bonds to the steel and/or the borehole wall to form a seal that resists high-pressure fluids from flowing past or through the sealed intervals. In abandoned wells, a cement plug may be used in the production casing to block off potential flow in the well.

We present in Figure 1.2-3 the iconic figure for well integrity introduced in the field of geologic carbon sequestration (Gasda et al., 2004) but very useful in the gas storage context also. As shown, multiple barriers are commonly employed in wells to contain high-pressure fluids. Nevertheless, sealing wells is challenging because of access limitations, the heterogeneous properties of subsurface formation, and extreme conditions of temperature, pressure, and fluids (e.g., acid gases creating corrosive environments). As shown in Figure 1.2-3, a host of failure modes for well seals is recognized.

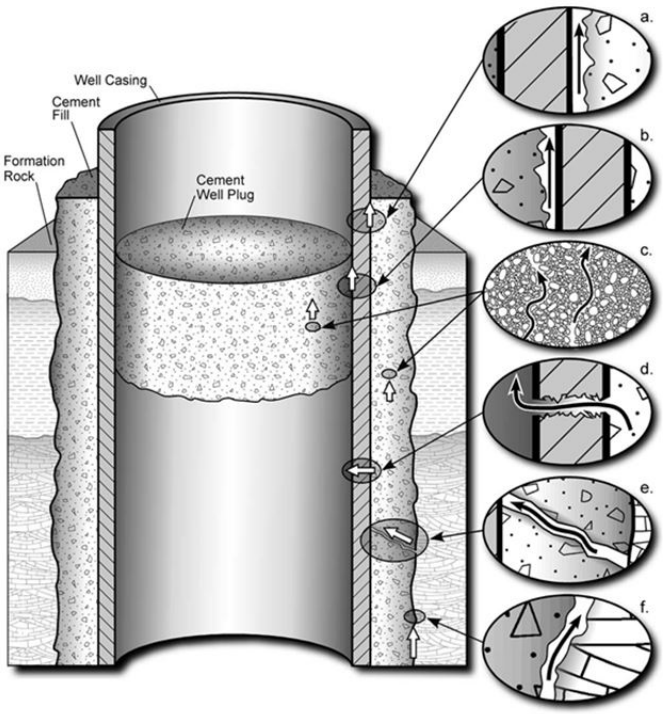


Figure 1.2-3. Three-dimensional cross section of a generic well (in this case shown with a cement plug for discussion purposes) showing production casing, cement, and formation along with various failure modes (a) bad seal between casing and cement; (b) bad seal between cement plug and casing; (c) leakage through the cement pore space as a result of cement degradation; (d) leakage through casing as a result of corrosion; (e) leakage through fractures in cement; and (f) leakage between cement and rock. From Gasda et al. (2004) (drawing by Dan Magee, Alberta Geol. Survey).

In addition to subsurface sealing capability, well integrity also relies on protection of the wellhead, e.g., from impacts such as those from vehicles or other heavy equipment. The wellhead forms the intersection of the surface and subsurface systems of UGS as shown in Figure 1.0-1. Looked at in more detail, well integrity vulnerability can be divided into surface threats and subsurface threats.

We present in Figure 1.2-4 a list of the numerous modes by which UGS wells can fail. This list was developed from the authors' experience with well integrity, along with review of multiple documents including API 1171 (API, 2015), the States First report (GWPC and IOGCC, 2017), Miyazaki (2009), and Michanowicz et al. (2017). As shown, the main well integrity issues can be divided into surface, casing or liner, tubing, and abandonment categories. Numerous components, events, and processes can lead to failure to contain fluid in the well. A great deal of information is contained in the list that is useful to understand well vulnerabilities and which can therefore be used to suggest corresponding monitoring and mitigation targets.

Well Integrity Issues:

- Surface Issues
  - Wellhead leakage
    - Valve leak
    - Fitting leak
    - Leaking around slips
    - Sand erosion
  - Third-party damage
    - Surface encroachment
    - Intentional/Unintentional damage
  - Seismic activity or other natural causes
- Casing or liner leaks
  - Internal corrosion
  - Annular fluid and gas issues
  - External corrosion – uncemented casing, flow zones, corrosion zones, other hydrocarbon zones, lost circulation zones
  - Casing shoe (seat)/formation integrity
  - Collar leaks
  - Cement integrity
    - Cement bond – pipe to formation
    - Microannulus
    - Channeled cement
    - Cement quality
  - Casing injection (packerless completion)
  - Gas production through gas mandrels (gas production through both the casing and tubing)
  - Uncemented liners
- Tubing leaks
  - Collar and thread leaks
  - Internal corrosion
  - Packer leaks
  - Annular fluid issues
- Plugging and abandonment leakage
  - Mechanical plug integrity
  - Cement plug integrity
  - Mud plug integrity
  - Temporary abandonment

Figure 1.2-4. Well Integrity Issues

Similar to the above list, we present in Figure 1.2-5 a list of the numerous ways by which loss-of-containment can occur due to failure of the geological part of a gas storage system (e.g., IPCC, 2005). We note that well integrity considerations appear in both the well and reservoir integrity lists (Figures 1.2-4 and 1.2-5), not only because of the reliance on the individual injection or production well to contain gas, but also for the reliance on surrounding wells to be sealing (outside of casing, i.e., against the formation) and not providing leakage pathways through the caprock. With this in mind, we present in Figure 1.2-6 a figure that further delineates failure modes in the well that can occur from external or internal changes in the engineered sealing capacity of the well (All Consulting, 2017; GWPC and IOGCC, 2017).

Reservoir Integrity Issues:

- Failure of the caprock/confining zone integrity
  - Overpressurization
  - Faults and fractures
  - Geomechanical stresses
- Geologic seal confinement – structural and stratigraphic traps
  - Anticlines
  - Pinch-outs
  - Facies changes
  - Faulting – frictional stability in a compartmentalized reservoir
    - Transmissive
    - Non-transmissive
  - Structural spill points and overfilling
  - Geological uncertainty – extent of reservoir boundary
    - Expansion, contraction, and migration of storage gas
    - Availability of pathways for migration
- Damage to the reservoir
  - Seismic activity
  - Contamination by foreign fluids
  - Storage formation damage
- Artificial penetrations – Breaches of vertical and horizontal containment
  - Third-party damage (drilling, completion, workover, and plugging activities)
  - Gas storage wells
  - Oil and gas production wells
  - Enhanced recovery and disposal wells
  - Plugged wells
  - Abandoned or improperly plugged wells
  - Temporarily abandoned wells
  - Monitoring or observation wells

Figure 1.2-5. Reservoir Integrity Issues.

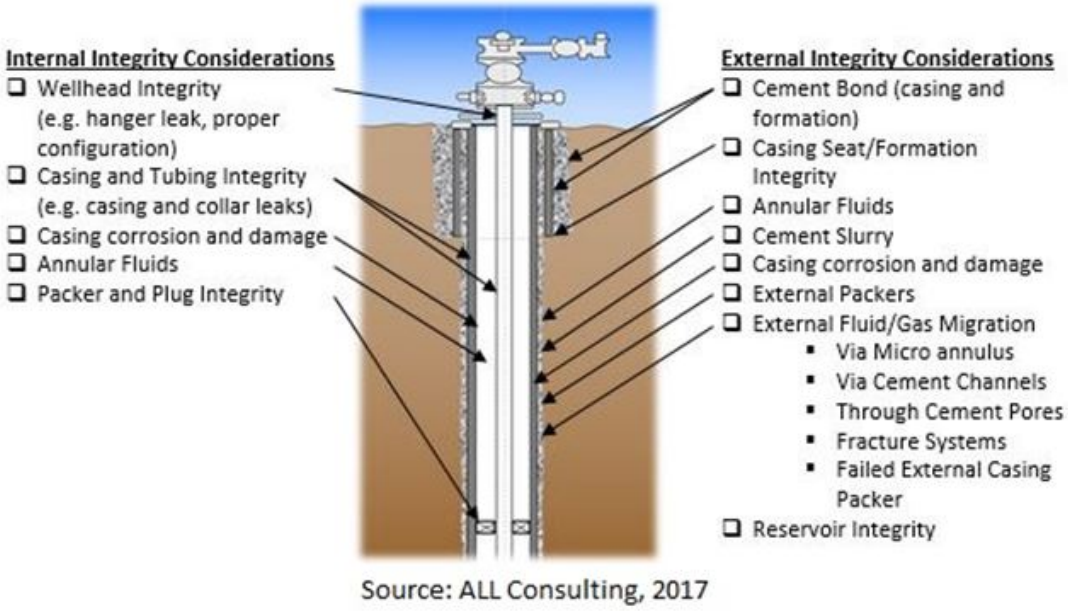


Figure 1.2-6. Well diagram showing internal and external integrity considerations (ALL Consulting, LLC, 2017).

1.2.3.5 Loss-of-containment from Surface System

A representative set of surface components of UGS systems in California is shown in Figure 1.0-1 up- or downstream of the wellhead, depending on whether injection or production are occurring, respectively. Although only a handful of representative components are depicted in Figure 1.0-1, the term *component* has been defined in new California Air Resources Board (CARB) regulations as any valve, fitting, flange, threaded-connection, process drain, stuffing box, pressure-vacuum valve, pressure-relief device, pipes, seal fluid system, diaphragm, hatch, sight-glass, meter, open-ended line, well casing, natural gas powered pneumatic device, natural gas powered pneumatic pump, or reciprocating compressor rod packing or seal (California Code of Regulations, 2017).

There are many failure modes applicable to surface UGS components, which are in fact the same components in wide use throughout industrial facilities such as oil and gas fields, oil refineries, chemical plants, factories, food processing plants, and power plants in California. A listing of the threats to gas pipelines has been outlined in the ASME B31.8S report on managing of system integrity of gas pipelines (ASME, 2016). We present in Figure 1.2-7 these threats in three categories (time-dependent, stable, and time-independent). As shown, time-dependent processes include corrosion, which is not confined to pipelines but rather can occur in any other steel component if not controlled and mitigated. Then there

are so-called stable threats, which implies that the pipeline (or component) has an inherent flaw or defect that does not necessarily worsen (or improve) with time. Finally, there are time-independent threats that can encompass the kinds of threats that persist over time, such as the potential for impacts to the pipeline (or component) including third-party impacts, vandalism, human error, and the natural hazards inherent to facility siting such as floods, landslides, wildfires, and earthquakes.

Failure modes common to surface piping, valves, compressors, etc. that are listed in Figure 1.2-7 to the left of "incorrect operational procedure" are continuously addressed through better inspection, engineering, manufacturing, security, and materials use. In fact, the surface components of UGS in California are mostly off-the-shelf components manufactured by reputable companies with long histories of quality control. Furthermore, surface components such as these are regularly inspected, maintained, and replaced by the facility operator or its contractors. Because there is nothing unique about UGS surface infrastructure for this subset of threats and related failure modes, we focus here on the failure modes of surface infrastructure that are unique to UGS in California, such as listed on the far-right-hand side of Figure 1.2-7.

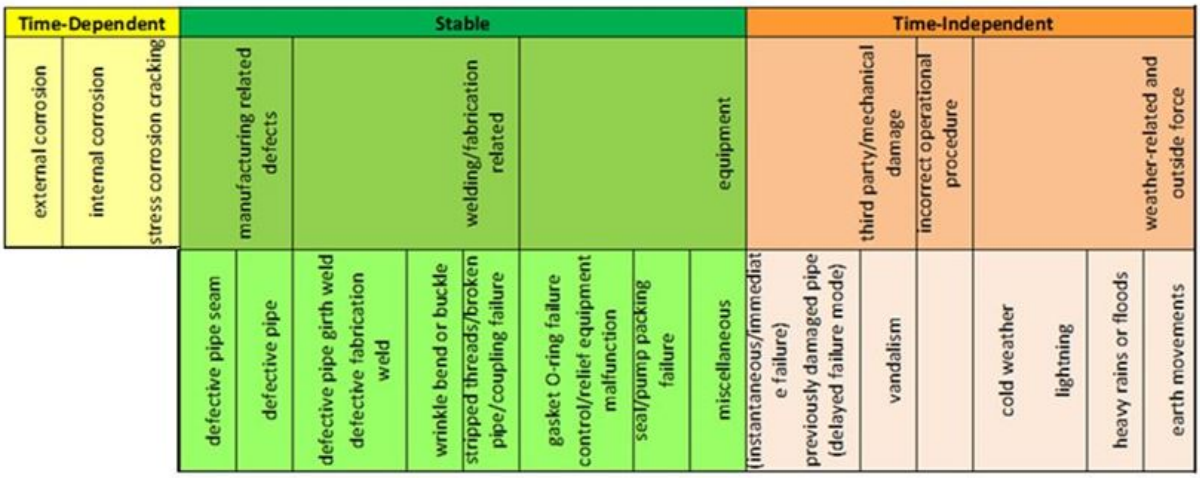


Figure 1.2-7. Time-dependent, stable, and time-independent threats to pipelines as summarized by Dynamic Risk (Calgary) and listed in ASME B31.8S (ASME, 2016).

In particular, the concerns for UGS in California most relevant to this study are the failure modes of the surface components critical to high-pressure gas containment that are caused by the challenging environments at the UGS sites. For example, failures of surface infrastructure at various California UGS facilities can occur as a result of landslides, earthquakes, tsunamis, floods, and wildfires. The main vulnerability is to the flowlines that along or above the ground surface, and the compressors and gas turbine facilities, along

with wellheads. At UGS facilities with significant topography such as Aliso Canyon, Honor Rancho, and Kirby Hills (see Section 1.1), landslide is a hazard that can lead to flowline failure through disruption of the pipe supports and corresponding buckling or shear of the pipe leading to rupture. Similarly, earthquakes can cause pipelines, buildings, and large equipment to be displaced from their supports and lead to ruptures. Finally, the La Goleta and Playa del Rey UGS facilities lie along the coast just a few feet above sea level. Tsunamis at those locations could cause inundation and water/debris impacts that could cause pipeline, surface infrastructure, and wellhead ruptures leading to loss-of-containment. Sea-level rise is also a potential long-term concern for these coastal facilities, as it is for the McDonald Island UGS facility located in the delta region. These specific hazards are discussed in more detail below.

In summary, the modes of failure of surface infrastructure at UGS facilities in California include all of the normal modes that are present in any facility with the same components, e.g., oil refineries, oil and gas fields, and any number of other factory, power plant, or chemical plant facilities. Because these common modes such as corrosion, weld failure, seal failure, etc. are not unique to gas storage, and there is widespread industry best practices and experience that lead to high reliability and low failure rate, we focus on the surface infrastructure failure modes that are unique to UGS in California. UGS operators do not have the option of locating facilities in the most optimally safe locations, but instead have to locate them where the reservoirs are. In California, this leads UGS facilities being located in a variety of physical settings, some of which are prone to landslides, earthquakes, tsunamis, flooding, and ground subsidence.

Details of these hazards at each facility as determined by various government agencies are presented below. The presence of a hazard at a facility does not necessarily imply risk at the facility due to the hazard, because the risk may be mitigated by engineering or other measures. For instance, at the McDonald Island facility, all of the plant facilities except some of the compressors are elevated on platforms, reducing the risk to operations of flooding substantially. Whether mitigation measures exist for hazards to each facility is not listed in this report. Such mitigation measures should be listed in the risk management plans for each facility, and the effectiveness of measures that are present should be quantified in those plans, as discussed in Section 1.6.

1.2.3.6 Landslide

Landslides are the common term for a wide variety of downslope mass movements as presented in Figure 1.2-8. In California, landslides are commonly caused by heavy rainfall and associated saturation of surface soils, and by seismically induced mobilization of hillslope rock and soil.

TYPE OF MOVEMENT		TYPE OF MATERIAL		
		BEDROCK	ENGINEERING SOILS	
			Predominantly coarse	Predominantly fine
FALLS		Rock fall	Debris fall	Earth fall
TOPPLES		Rock topple	Debris topple	Earth topple
SLIDES	ROTATIONAL	Rock slide	Debris slide	Earth slide
	TRANSLATIONAL			
LATERAL SPREADS		Rock spread	Debris spread	Earth spread
FLOWS		Rock flow (deep creep)	Debris flow (soil creep)	Earth flow
COMPLEX		Combination of two or more principal types of movement		

Figure 1.2-8. Abbreviated version of Varnes' (1978) classification of slope movements. (USGS, 2014).

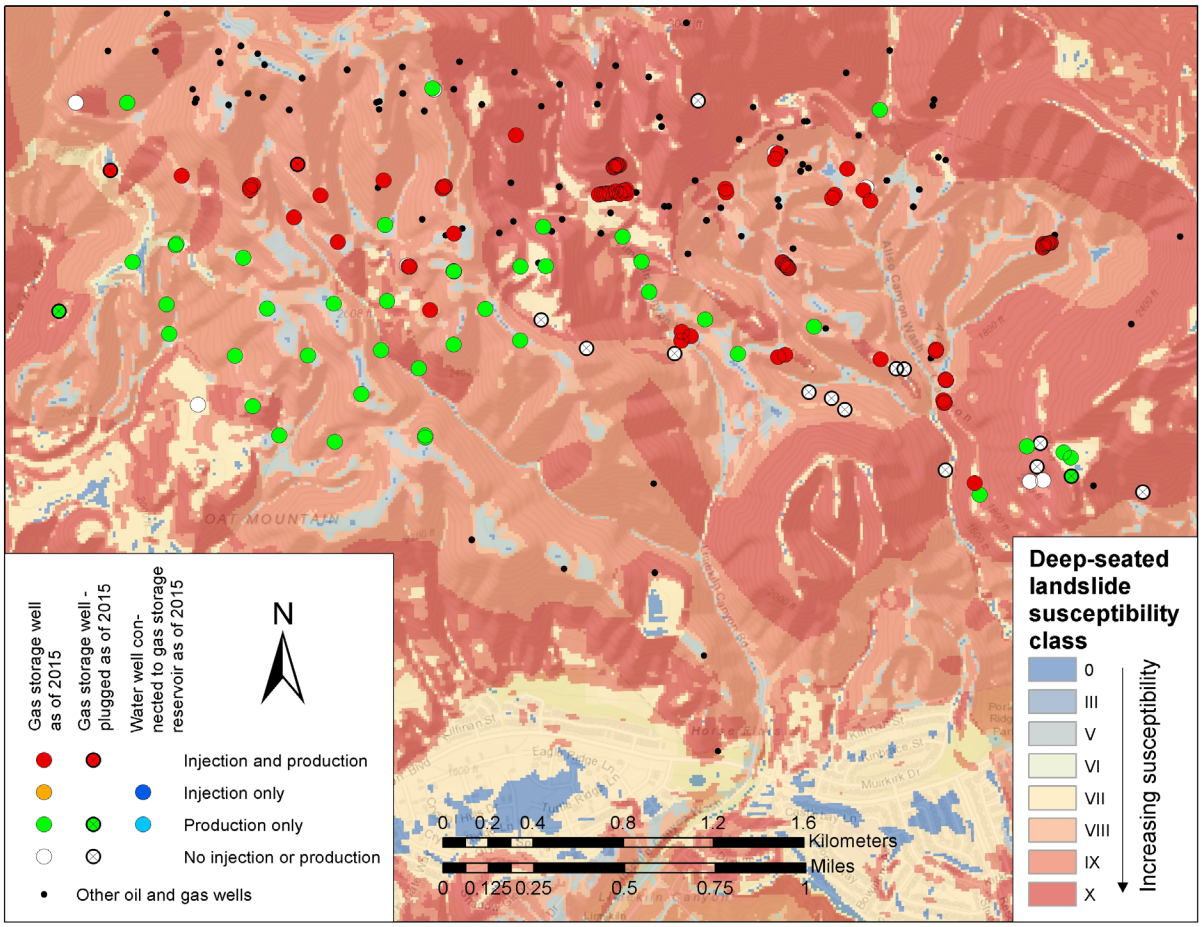
Regardless of cause, landslides are a hazard to UGS infrastructure. UGS wells can be sheared in the subsurface by movement of deep-seated (rotational and translational) landslides, and surface infrastructure can be severely impacted by landslides through (1) direct impact of soil and debris, e.g., into a flowline or wellhead, and (2) sliding or undermining of the ground beneath supports or foundations for surface infrastructure, e.g., flowlines, compressor, or gas processing foundations. In this latter case, loss of ground support could lead to collapse of a flowline or its support and subsequent rupture, bending, or compression of the line leading to failure and LOC. For compressors or other large infrastructure, loss of ground support could lead to collapse and the breaching or detachment of supply flowlines containing high-pressure gas. Loss-of-containment could result from any or all of these failure modes.

Susceptibility to deep-seated landslides in California is mapped by Wills et al. (2011) based on the assignment of land areas to one of eight classes (0, III, V, VI, VII, VIII, IX, and X) ranging from least to most susceptible. Assignments were made based on a combination of slope and rock strength. As such, the assignments do not take into account the probability of triggering events such as precipitation and earthquake shaking. Table 1.2-1 provides the predominant and maximum class (in parentheses) for each type of surface infrastructure for each UGS facility in California. The table does not include the local susceptibility to compressors or gas processing equipment (i.e., at the plant), because the susceptibility map is not meant to be used for such small locations.

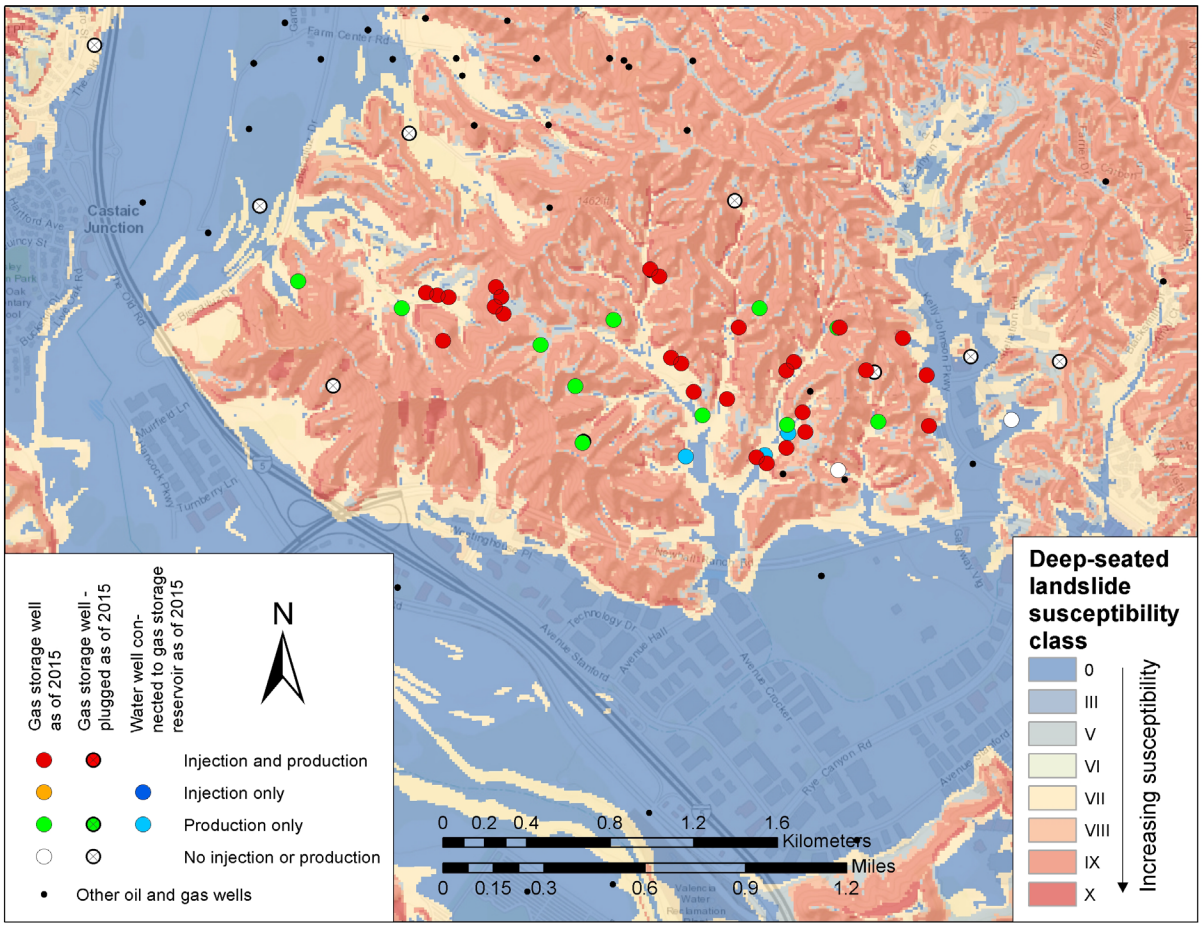
Table 1.2-1. Deep-seated landslide susceptibility classes at each facility from Wills et al., 2011. Predominant class is followed by maximum class (in parentheses). Pink tint indicates classes III and V, light red tint classes VI and VII, and red classes IV and X (class XIII does not occur in table).

	Facility	Well(s) and flowline(s)	Interconnect
Independents	Gill Ranch Gas	0 (0)	0 (0)
	Kirby Hill Gas	0 (VI)	0 (VII)
	Lodi Gas	0 (0)	0 (0)
	Princeton Gas	0 (0)	0 (0)
	Wild Goose Gas	0 (0)	0 (0)
PG&E	Los Medanos Gas	0-III (VI)	0 (III)
	McDonald Island Gas	0 (0)	0 (0)
	Pleasant Creek Gas	0 (VII)	0 (V)
SoCalGas	Aliso Canyon	IX (X)	IX (X)
	Honor Rancho	IX (IX)	XII (X)
	La Goleta Gas	0 (X)	0 (0)
	Playa del Rey	0 (X)	0 (X)

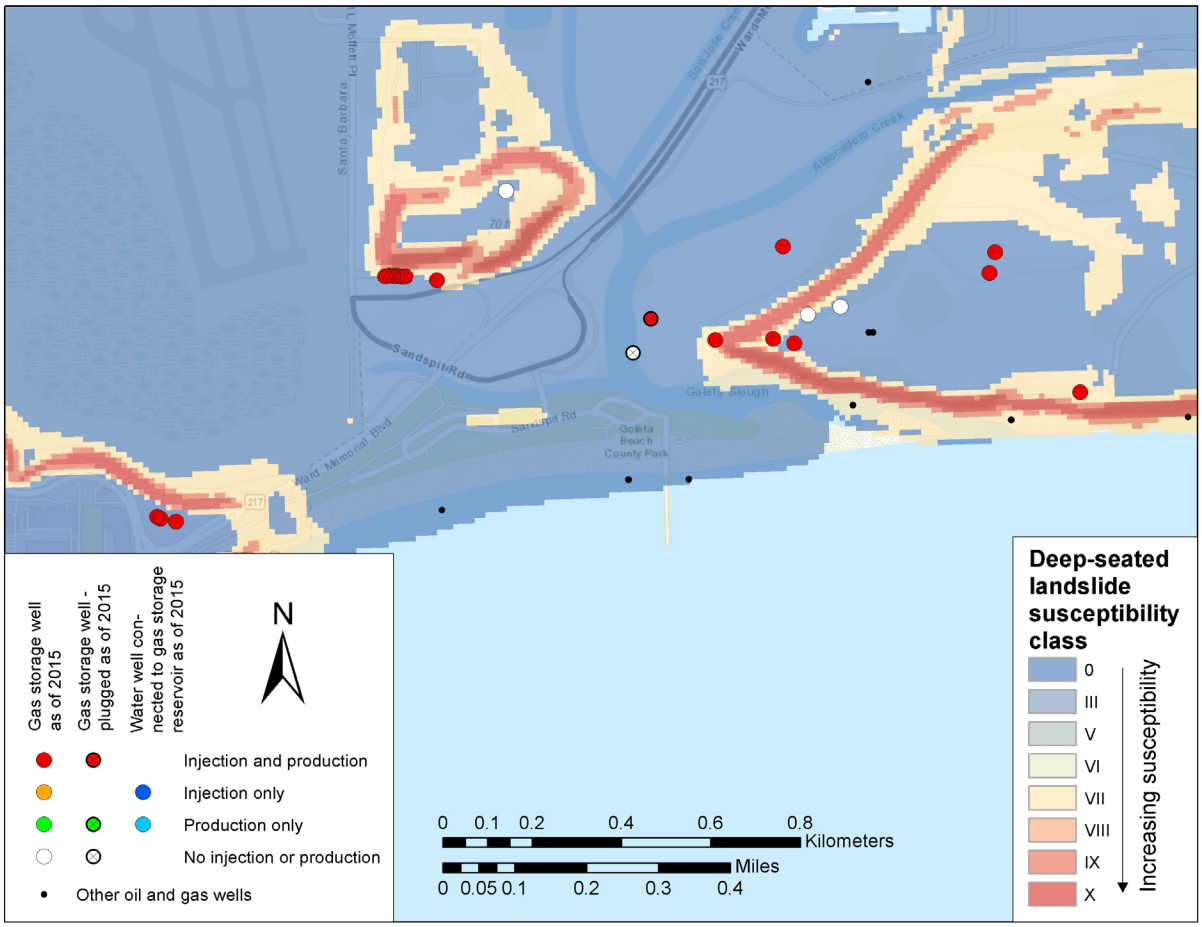
The southern California facilities have the highest susceptibility to deep-seated landsliding, and the independently operated facilities in central and northern California have the least susceptibility as a group. Figure 1.2-9 shows the deep-seated landslide susceptibility at the southern California facilities.


Gas storage well as of 2015
Gas storage well - plugged as of 2015
Water well connected to gas storage reservoir as of 2015
N
Injection and production
Injection only
Production only
No injection or production
Other oil and gas wells
0 0.2 0.4 0.8 1.2 1.6
Kilometers
0 0.125 0.25 0.5 0.75 1
Miles
Deep-seated landslide susceptibility class
0
III
V
VI
VII
VIII
IX
X
Increasing susceptibility

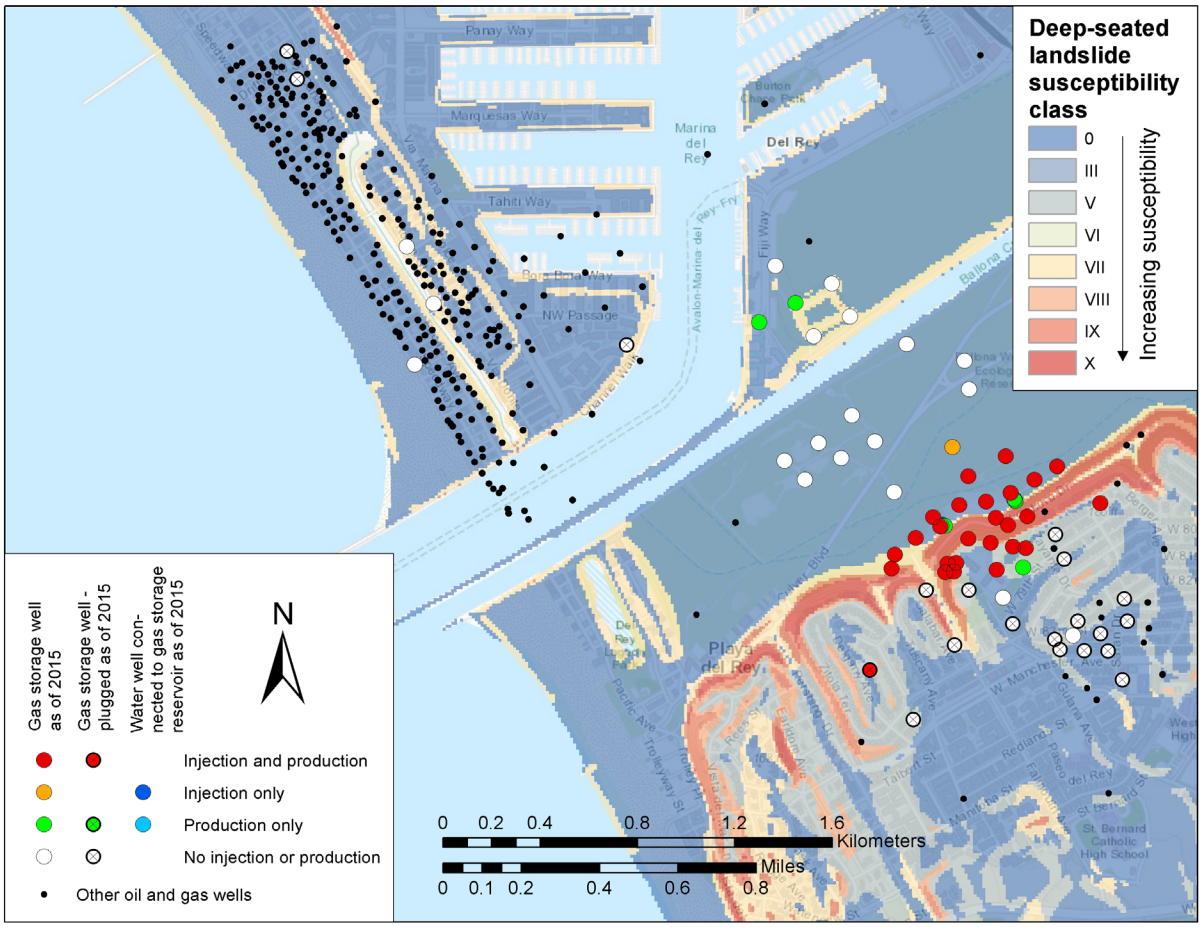
(a)


Castaic Junction
Farm Center Rd
Old Rd
Technology Dr
Avenue Stanford
Avenue Hall
Avenue Crocker
Rye Canyon Rd
Gateway Vg
Gas storage well as of 2015
Gas storage well - plugged as of 2015
Water well connected to gas storage reservoir as of 2015
N
Injection and production
Injection only
Production only
No injection or production
Other oil and gas wells
0 0.2 0.4 0.8 1.2 1.6
Kilometers
Miles
0 0.15 0.3 0.6 0.9 1.2
Deep-seated landslide susceptibility class
0
III
V
VI
VII
VIII
IX
X
Increasing susceptibility

(b)


Santa Barbara
Sandspit Rd
Ward Memorial Blvd
Goleta Slough
Goleta Beach County Park
Atascadero Creek
San Jose Cree
Gas storage well as of 2015
Gas storage well - plugged as of 2015
Water well con-nected to gas storage reservoir as of 2015
Injection and production
Injection only
Production only
No injection or production
Other oil and gas wells
N
0 0.1 0.2 0.4 0.6 0.8 Kilometers
0 0.05 0.1 0.2 0.3 0.4 Miles
Deep-seated landslide susceptibility class
0
III
V
VI
VII
VIII
IX
X
Increasing susceptibility

(c)



(d)

Figure 1.2-9. Deep-seated landslide susceptibility at the southern California facilities from Wills et al. (2011) (a) Aliso Canyon, (b) Honor Rancho, (c) La Goleta, and (d) Playa del Rey.

1.2.3.7 Earthquake

The active tectonics and pervasive faulting in California mean that every UGS facility in the state is subject to some level of seismic hazard. Earthquakes can damage surface infrastructure by direct fault displacement, shaking, and ground deformation due to liquefaction and earthquake-induced landslides.

Seismic hazard analyses carried out jointly by the California Geological Survey (CGS) and the U.S. Geological Survey (USGS) to assess the potential for damaging ground shaking throughout the state consider major faults that show evidence for activity within the last 1.6 million years (the Quaternary geological period). These fault characterizations are also used for more detailed site-specific analyses of the potential for ground shaking

and fault displacement. Calculation of the probabilities of these events occurring in the future—the ground shaking or fault displacement hazard—is based on the long-term rates of displacement on the faults, which are used to estimate the average time periods over which earthquakes recur. An example of seismic hazard assessment in the field of geologic carbon sequestration is given by Foxall et al. (2017). The latest ground shaking hazard assessment for California and site-specific analyses at one UGS facility currently in progress are summarized later in this section.

Fault displacement can affect surface infrastructure if fault displacement occurs in the footprint of the facility component, e.g., fault displacement through the concrete foundation of a compressor. And fault displacement can affect wells at depth through shearing of the well casing if the well crosses the plane of the fault, e.g., a dipping thrust or normal fault, on which there is slip during an earthquake or by aseismic creep.

Specifically to address surface fault displacement hazards, CGS has mapped Earthquake Fault Zones (EFZs) throughout much of the state where evidence exists for movement on a fault rupturing the ground surface during the past 11,000 years (the Holocene epoch; http://www.conservation.ca.gov/cgs/rghm/ap). Certain proposed projects, such as buildings with multiple residences, that are proposed within an EFZ must conduct a site-specific investigation to identify the location of past ground surface ruptures, if present, and set back project elements from those locations.

The location of surface infrastructure at the 12 current UGS facilities was compared to EFZ maps where they exist. All the facilities were also compared to the Quaternary Fault and Fold Database of the United States (USGS and CGS, 2006), which maps faults in California with evidence of ground surface rupture in the Quaternary period. These comparisons provide a perspective on whether an area was not mapped for EFZs because there is no fault suspected of rupturing the surface in the last 11,000 years, or because the CGS has not yet mapped EFZs in the area. It also enables an assessment of the potential for both surface and subsurface displacement on less active Quaternary faults.

As shown in Table 1.2-2, only the interconnect at Aliso Canyon is transected by the surface trace of a Holocene fault. Some wellheads in the Aliso Canyon and Honor Rancho facilities are located within an EFZ. No gas was transferred via these wells during the study period, suggesting they are used as observation wells. No flowlines to these wells are shown in the NPMS data; however, these data are missing some flowlines in both of these facilities, so such lines may exist within the EFZ at each facility. Even if such lines exist, they may not contain pressurized gas. Insofar as the wells are connected to the storage reservoir, they could be involved in an LOC incident regardless of whether or not they are currently used for production or injection. Faults listed in the vicinity of wellheads and flowlines in Table 1.2-2 are discussed further below. Faults listed as in the vicinity of interconnects are not discussed, because this hazard is not unique to UGS but rather is analogous to the far more numerous instances of faults with Quaternary rupture in the vicinity of gas pipelines throughout the state not related to storage.

Table 1.2-2. Mapped Quaternary faults at UGS facilities according to USGS and CGS (2006), and Earthquake Fault Zone (EFZ) mapping. Rows for facilities partially within an Earthquake Fault Zone are shaded red.

	Facility	Fault[1]	Last rupture (yrs ago)[1]		7.5′ quadrangle mapped for EFZs	Source
			Wellhead(s) and flowline(s)	Interconnect(s)		
Independents	Gill Ranch Gas	None			No	
	Kirby Hill Gas	Vaca	<130,000	<130,000	No	
		Kirby Hills	<130,000*			
	Lodi Gas	Unnamed		<1,600,000*	No	
	Princeton Gas	None			No	
	Wild Goose Gas	None			No	
PG&E	Los Medanos Gas	Unnamed	<130,000*		Yes[1]	1CGS (1993)
	McDonald Island Gas	None			No	
	Pleasant Creek Gas	None			No	
SoCalGas	Aliso Canyon	Santa Susana	<15,000*	<15,000	Yes[2]	2CGS (1976)
			<130,000	<130,000		
		Mission Hills		<130,000		
	Honor Rancho	San Gabriel	<15,000*		Yes[3]	3CGS (1995a,b)
			<130,000*			
		Holser	<130,000*	<130,000*		
	La Goleta Gas	More Ranch	<130,000*	<130,000*	No	
	Playa del Rey	Charnock		<130,000	No	

*Fault trace within 500 m of surface infrastructure

The faults in USGS and CGS (2006) at the Kirby Hill facility are shown in Figure 1.2-10. The Kirby Hills fault is shown as passing through the field by DOG (1982). Note that the name of the field in which this facility is located is “Kirby Hill Gas,” while the name of the fault is “Kirby Hills.” Consequently, it may pass through some of the storage wells; however, this is uncertain because the fault appears to be almost vertical. Parsons et al. (2002) indicate earthquakes have been recorded on this fault at depth, and that to the south, the fault deforms the “youngest” sedimentary rock. A very high resolution seismic reflection profile across the fault in the Sacramento River also suggests movement on the fault has deformed sediments deposited by the river.

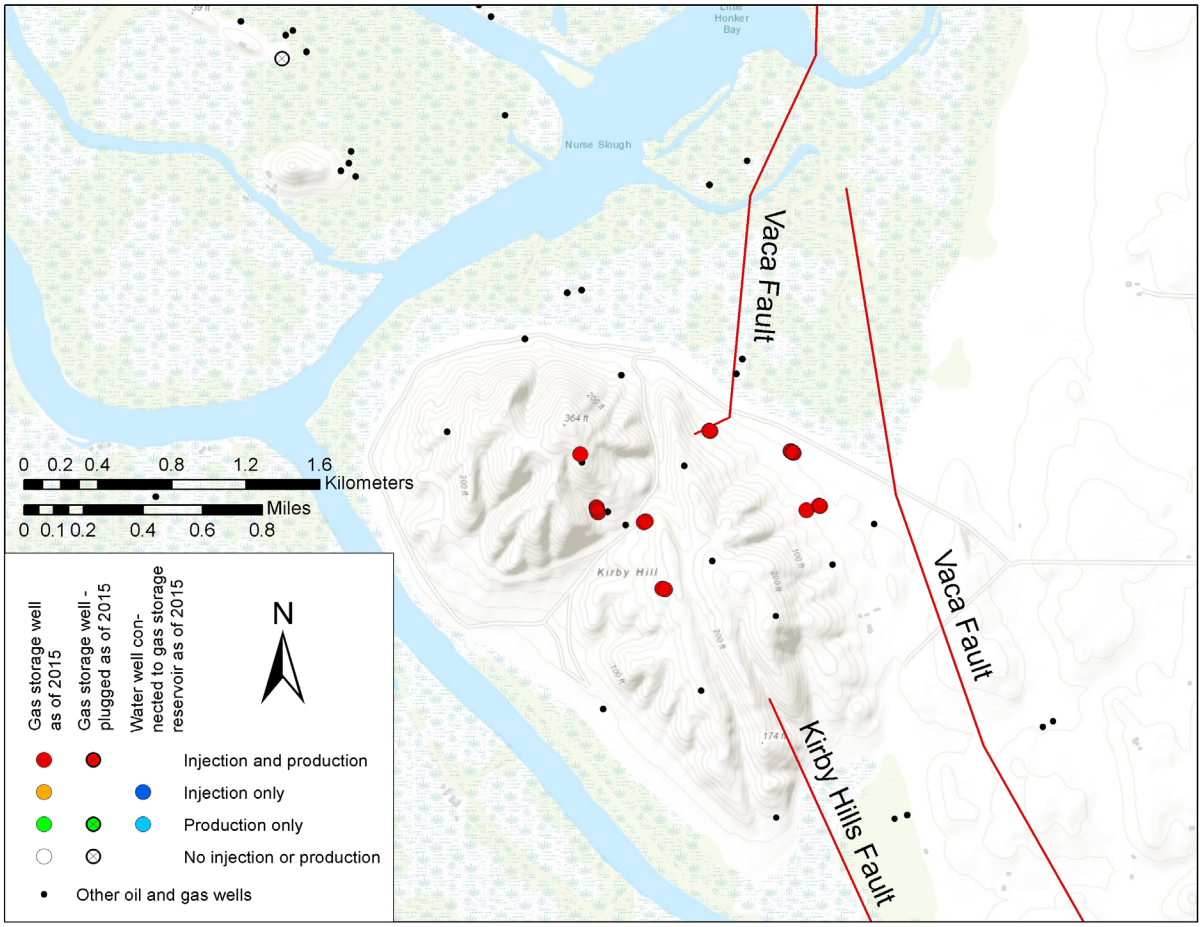


Figure 1.2-10. Vaca and Kirby Hills fault traces that ruptured in the last 130,000 years in the vicinity of the Kirby Hill facility shown in red (USGS and CGS, 2006).

The faults with surface rupture in the Quaternary in the vicinity of the Los Medanos facility are shown in Figure 1.2-11. Based on the linearity of the fault traces across topography with relief, the faults appear to be vertical, or nearly so. No vertical faults are shown on the cross section through the Main area, which is where storage is located (DOG, 1982). Consequently, there is likely no hazard of storage wells being sheared by rupture of these faults. However, the Los Medanos Hills thrust fault passes above the storage reservoir (Hoffman, 1992) and is listed as Quaternary active by Unruh and Sundermann (2006). Consequently, the storage wells are susceptible to hazard of being sheared by movement on this fault.

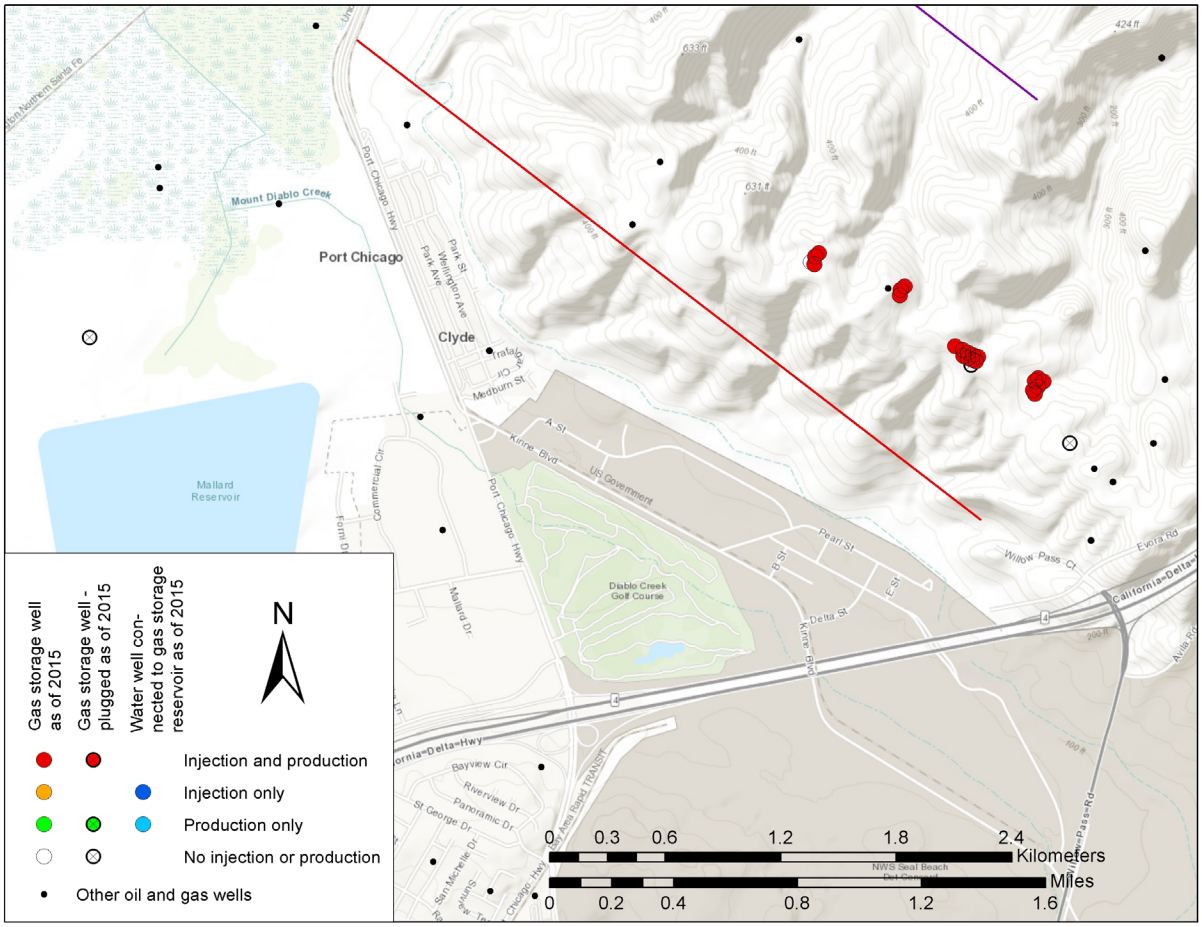


Figure 1.2-11. Unnamed fault traces that ruptured in the Quaternary in the vicinity of the Los Medanos facility. Rupture in the last 1.6 million years shown in purple and the last 130,000 years shown in red (USGS and CGS, 2006).

The EFZ at Aliso Canyon is shown in Figure 1.2-12. This EFZ corresponds to a segment of the Santa Susana fault that was active during the last 11,000 years, the surface trace of which ends just to the southeast of the facility (Figure 1.2-12). Approximately 3 km farther east, surface displacement on the Santa Susana fault occurred during the 1971 magnitude 6.5 Sylmar-San Fernando earthquake. The most recent rupture of the section of the Santa Susana fault trace that continues westward to the south of the Aliso Canyon facility and another trace through its western edge is given as occurring less than 130,000 years ago (Figure 1.2-12).

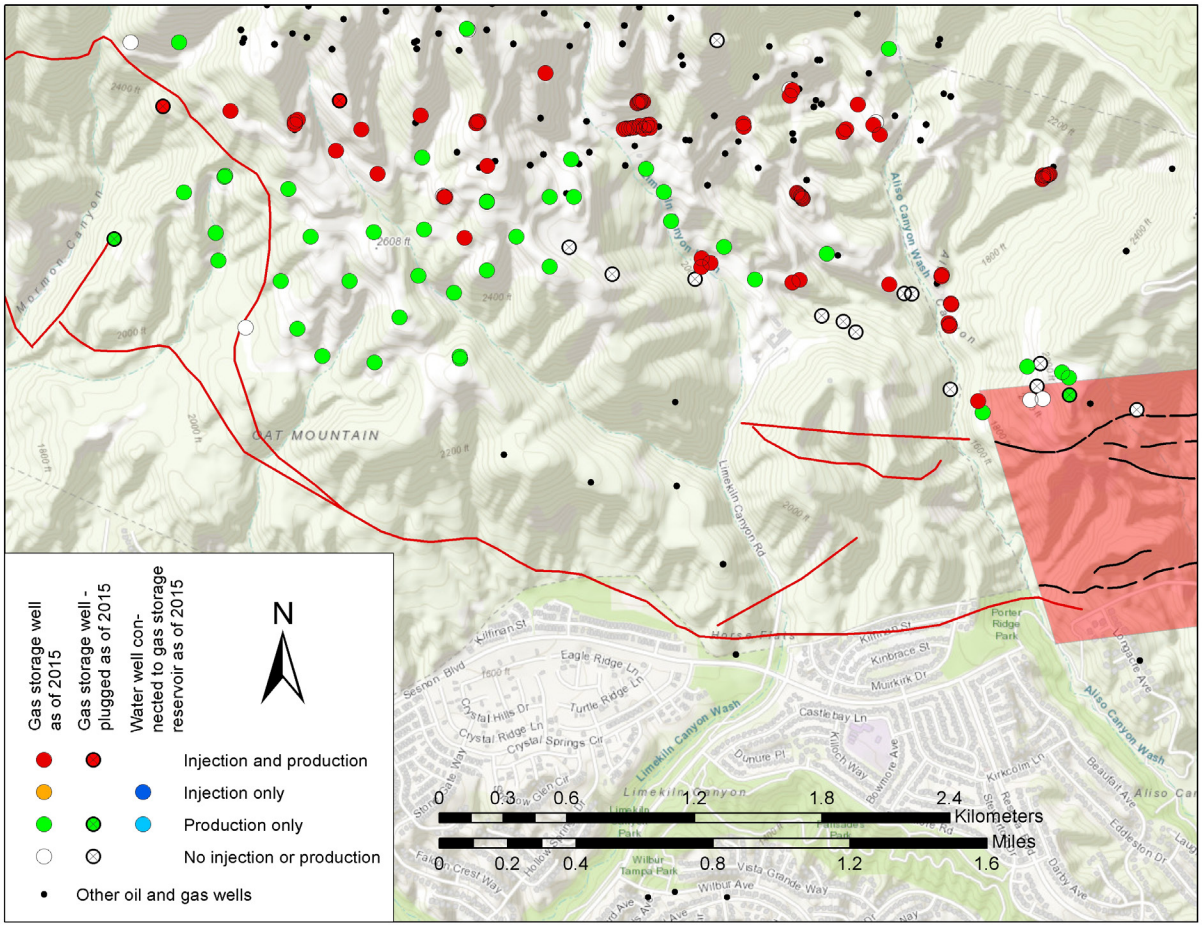


Figure 1.2-12. Earthquake Fault Zone (EFZ) at the Aliso Canyon facility shown in red tint (CGS, 1976). Fault traces that ruptured during the last 15,000 years are shown in black, and traces that show evidence for activity during the last 130,000 years are shown in red (USGS and CGS, 2006).

The long-term slip rate assigned to the Santa Susana fault in Version 3 of the authoritative Uniform California Earthquake Rupture Forecast (UCERF3; Field et al., 2014) model is 6 mm/year, which is one of the highest rates for a reverse fault in the Western U.S. However, the overall characterization of the fault is subject to significant uncertainty, and the bounds on this estimate range from 0.5 to 10 mm/year. This is because the relatively high slip rate estimate is only indirectly constrained (Huftile and Yeats, 1996; Yeats, 2001), and appears to be incompatible with the geomorphic expression of the fault. The age of latest displacement on this segment of the fault is also very poorly constrained (Lung and Weick, 1987).

The subsurface geometry of the Santa Susana fault system at Aliso Canyon is particularly well defined by abundant well data, as shown in Figure 1.2-13. Above 1.5 km depth, the system comprises three north-dipping fault strands and the associated buried Roosa and Ward faults. The Younger Santa Susana strand is considered to be the most active. While the wellheads of only two wells active in 2015 are located within the EFZ, all of the Aliso Canyon wells penetrate the Younger strand of the Santa Susana fault in the subsurface, and some of them also penetrate the Upper Older strands. It appears likely that the fault strand penetrated by the wells to the storage reservoir along the eastern margin of the facility corresponds to the surface trace mapped as active during the last 11,000 years. The maximum magnitude estimated in UCRF3 for the Santa Susana fault is 6.6 to 7.3, which corresponds to fault displacements in the approximate range of 0.5 to 2.5 meters. A portion of the interconnect is also located in the EFZ.

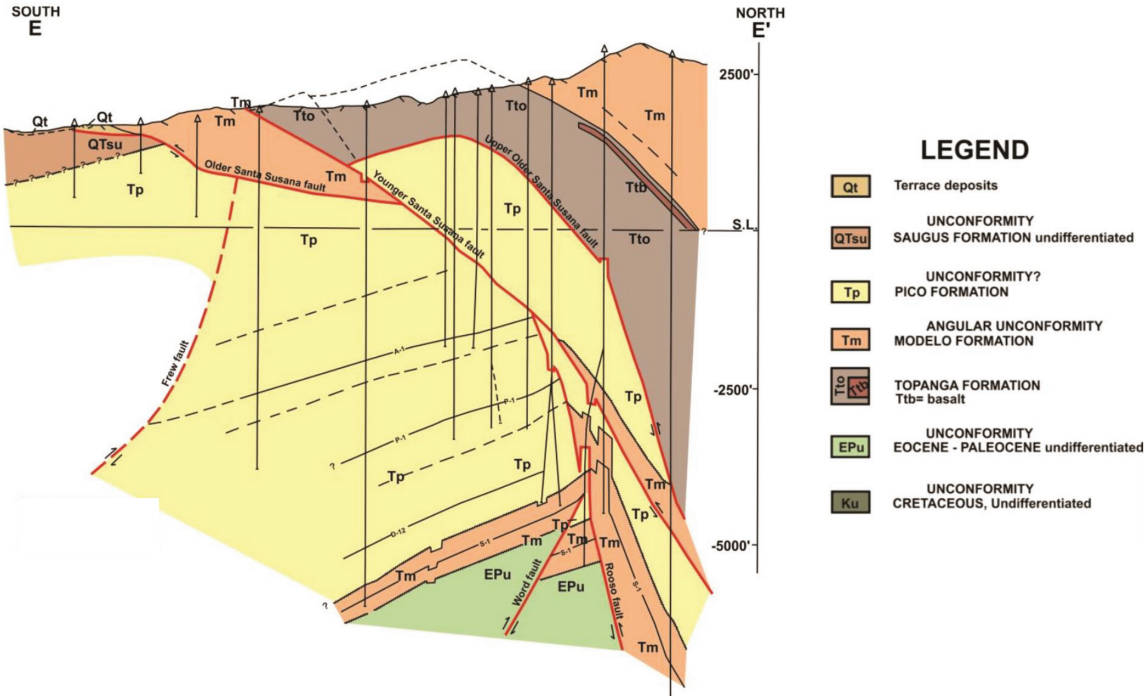


Figure 1.2-13. North-south cross section through the Aliso Canyon facility about one km west of the western end of the EFZ shown in Figure 1.2-12. Vertical lines represent wells. The storage reservoir is in the Modelo Formation (Davis et al., 2015).

The EFZ at Honor Rancho is shown in Figure 1.2-14. While only one well was open in the EFZ in 2015, the EFZ is for the San Gabriel Fault. USGS and CGS (2006) indicate displacement on this fault is dextral (the far-side moves to the right). As such, the fault surface is likely to be near vertical, although it dips to the northeast in the shallow

subsurface. Therefore, it is unlikely that the portion of the fault within the EFZ intersects any active wells in the subsurface. The cross section through the Honor Rancho field Main area in DOGGR (1998), which is approximately perpendicular to the fault, does not show the fault, which tends to confirm this interpretation.

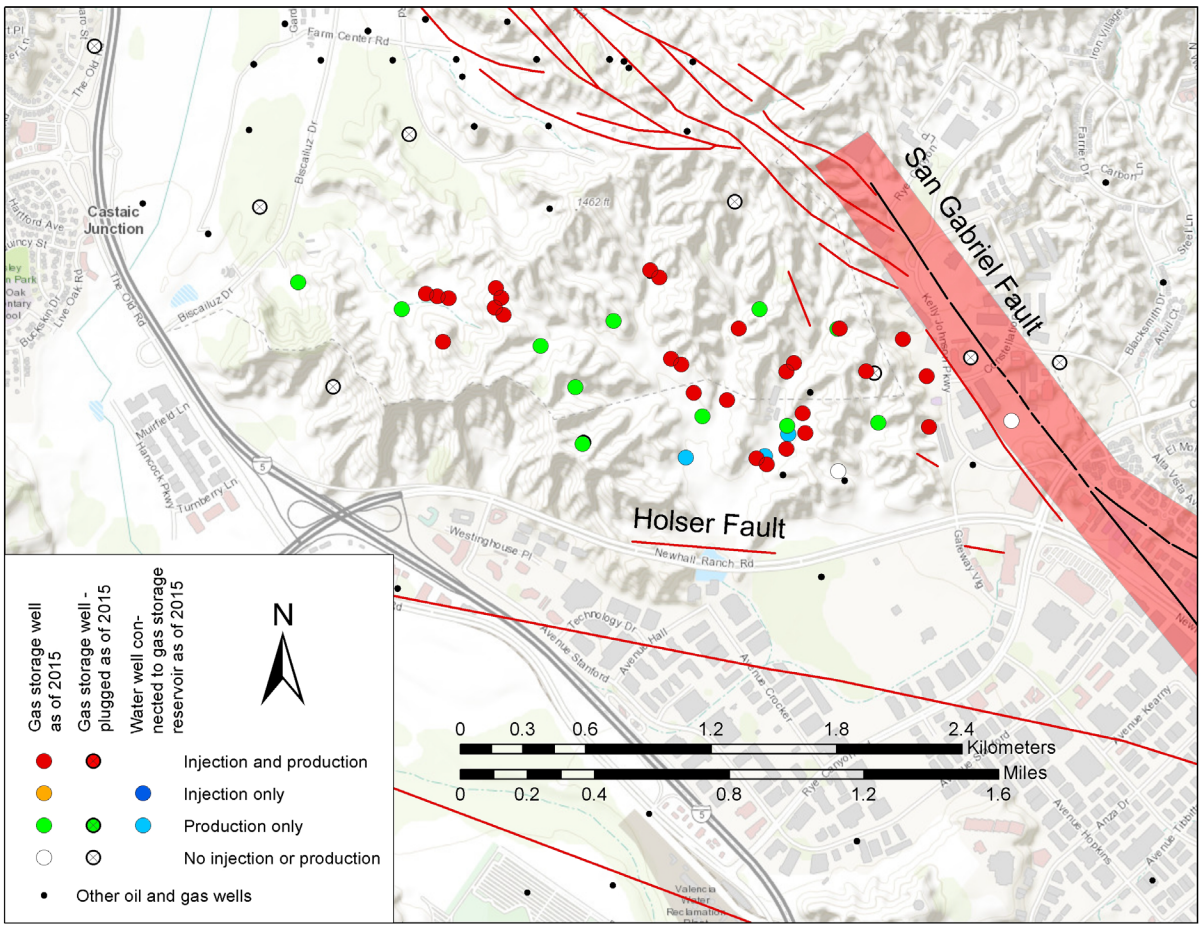


Figure 1.2-14. Earthquake Fault Zone (EFZ) at the Honor Rancho facility shown in red tint (CGS, 1995a). Fault traces ruptured in the last 11,000 years are shown in black, and traces ruptured in the last 130,000 years shown in red (USGS and CGS, 2006).

At the northern end of the Holocene-active segment shown in Figure 1.2-14, the San Gabriel fault zone bends to strike northwest with a most recent rupture in the last 130,000 years. There are short traces of the San Gabriel fault that ruptured in the last 130,000 years that are up to the margins of the facility. Rupture of these, should it occur, is more likely to intersect wells in the subsurface.

The short trace of the Holser fault is within 500 m south of the Honor Rancho facility, as shown in Figure 1.2-14. This is a south-dipping reverse fault (Jennings and Bryant, 2010). As such, it dips away from the facility and is unlikely to intersect any storage wells.

Three traces of the west-striking More Ranch fault, which last ruptured during the last 130,000 years, are mapped within 0.5 km north of the La Goleta facility (USGS and CGS, 2006), as shown in Figure 1.2-15. The More Ranch fault dips to the south (Keller and Gurrola, 2000). The fault is a section of the approximately 70 km long Mission Ridge-Arroyo Parida-Santa Ana fault system. The entire fault system is assigned a Late Quaternary long-term slip rate of 0.4 to 1.6 mm/year in the UCERF3 model, but the estimate for the More Ranch fault itself is 0.3 mm/year based on local field data. The maximum earthquake magnitude for the entire system is estimated at 6.8 to 7.3, corresponding to fault displacements of approximately one to two meters.

At storage depth, the More Ranch fault is also to the north (Olson, 1982; Davis Namson Consulting Geologists, 2005). Since all the storage wellheads in the facility are located south of the More Ranch fault traces, as shown on Figure 1.2-15, presumably none is at risk of being directly sheared by the fault due to crossing it. However, a Final Environmental Impact Report certified in 2013 regarding the proposed installation of four new wells included one that would cross the fault to test for the existence of a gas-filled trap north of the fault (Santa Barbara County Planning and Development Department, 2013). If such gas were as encountered, it would be withdrawn and then utilized for additional storage at the facility. A review of DOGGR's well finder indicates this well (Chase and Bryce 3) does not exist, and there is no permit for its construction. However, if such a well or wells are ever developed at this facility, they would be at risk of shearing by rupture of the More Ranch fault.

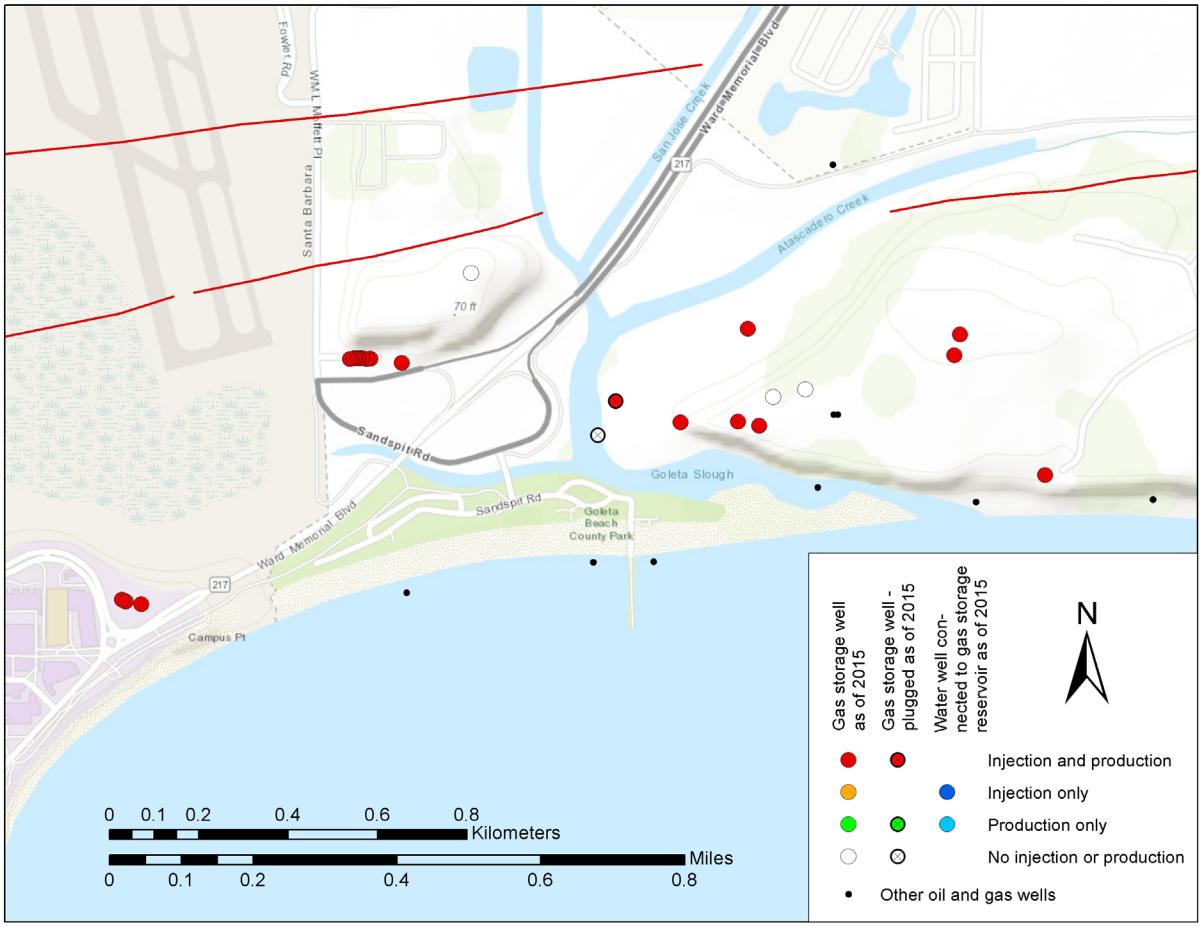


Figure 1.2-15. More Ranch fault traces north of the La Goleta facility that ruptured in the last 130,000 years shown in red (USGS and CGS, 2006).

Figure 1.2-16 shows maps of major faults and earthquake shaking potential in California. As shown, the Los Angeles Basin and nearby coastal areas have numerous faults and significant seismic hazards.

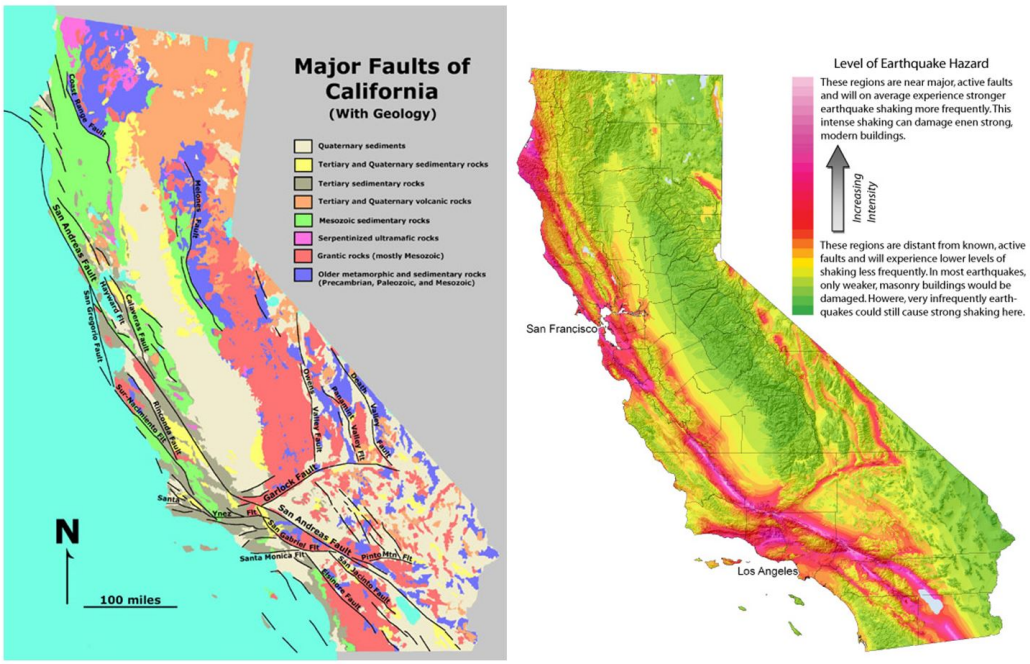


Figure 1.2-16. (a) Major faults and general geology of California (Source: http://geologycafe.com/erosion/tectonics.html accessed 7/17/17) (b) Earthquake shaking potential in California (Branum et al., 2016).

The CGS and USGS seismic hazard assessment for California include estimates of the 0.2-second spectral acceleration during earthquakes with a 2% chance of being exceeded in a 50-year period (Branum et al., 2016) and the 1.0-second spectral acceleration with the same chance of being exceeded (Branum et al., 2016). (Spectral acceleration is a standard measure related to the responses of buildings with different resonance periods. These frequencies typically correlate to building height. Taller buildings have longer resonance periods and so respond most strongly to lower frequencies.) Table 1.2-3 lists spectral accelerations for each type of surface infrastructure at each facility. Because of their different proximities to active faults, the southern California facilities have the highest anticipated accelerations, and the independently operated facilities in central and northern California, with the exception of Kirby Hills, have the lowest.

Table 1.2-3. 2% chance of spectral acceleration exceedance in 50 years (Branum et al., 2016). 0.2-second period accelerations greater than 1 g and 1.0-second period accelerations greater than 0.5 g are tinted pink. 0.2-second period accelerations greater than 2 g and 1.0-second period accelerations greater than 1.0 g are tinted light red. 1.0-second period accelerations greater than 3.0 g are tinted dark red. (g is the acceleration due to gravity.)

	Facility	Infrastructure	Spectral acceleration (fraction of g)	
			0.2-second	1.0-second
Independents	Gill Ranch Gas	Wellhead(s)	0.85	0.45
		Flowline(s)	0.85	0.45
		Plant	0.85	0.45
		Interconnect	0.85-1.45	0.45
	Kirby Hill Gas	Wellhead(s)	1.55	0.55
		Flowline(s)	1.55	0.55
		Plant	1.55	0.55
		Interconnect	1.25-1.55	0.55-0.75
	Lodi Gas	Wellhead(s)	0.65	0.35
		Flowline(s)	0.65	0.35
		Plant	0.65	0.35
		Interconnect	0.65-1.25	0.35-0.85
	Princeton Gas	Wellhead(s)	0.75	0.45
		Flowline(s)	0.75	0.45
		Plant	0.75	0.45
		Interconnect	0.75-0.95	0.35-0.55
	Wild Goose Gas	Wellhead(s)	0.65	0.45
		Flowline(s)	0.65	0.35-0.45
		Plant	0.65	0.45
		Interconnect	0.65	0.35-0.45
PG&E	Los Medanos Gas	Wellhead(s)	2.05-2.15	0.75-0.85
		Flowline(s)	2.05-2.15	0.75-0.85
		Plant	2.05-2.15	0.75
		Interconnect	2.05-2.15	0.75
	McDonald Island Gas	Wellhead(s)	1.15	0.75
		Flowline(s)	1.15	0.75
		Plant	1.15	0.75
		Interconnect	1.15-1.25	0.55-0.85
	Pleasant Creek Gas	Wellhead(s)	1.75	0.85
		Flowline(s)	1.75-1.85	0.75-0.85
		Plant	1.85	0.75
		Interconnect	1.85	0.65-0.75

	Facility	Infrastructure	Spectral acceleration (fraction of g)	
			0.2-second	1.0-second
SoCalGas	Aliso Canyon	Wellhead(s)	2.45-2.55	1.45
		Flowline(s)	2.45-2.55	1.45
		Plant	2.55	1.45
		Interconnect	2.45-2.75	1.15-1.45
	Honor Rancho	Wellhead(s)	2.25-2.45	0.95-1.15
		Flowline(s)	2.25-2.45	0.95-1.15
		Plant	2.45	1.05
		Interconnect	2.45	1.05
SoCalGas	La Goleta Gas	Wellhead(s)	2.65	1.45-1.55
		Flowline(s)	2.65	1.45-1.55
		Plant	2.65	1.45
		Interconnect	2.65	1.45
	Playa del Rey	Wellhead(s)	1.35-1.65	0.75-0.95
		Flowline(s)	1.35-1.65	0.75-0.95
		Plant	1.35-1.55	0.75-0.95
		Interconnect	1.35-1.55	0.75-0.95

The CGS has mapped Liquefaction and Earthquake-induced Landslide Zones throughout most of the urbanized portions of the Los Angeles Basin, Antelope Valley, San Francisco Peninsula, East San Francisco Bay Area, and South San Francisco Bay Area. These ground deformations can damage both surface and subsurface infrastructure. As such, certain structures, such as buildings with multiple residences that are proposed within these Seismic Hazard Zones (SHZs) must conduct a site-specific investigation to identify if the hazard is present, and if so to mitigate the hazard.

Table 1.2-4 lists which UGS facilities have been mapped for SHZs, and for those facilities each class of surface infrastructure in each type of SHZ. For the facilities not in SHZs, the presence or absence of the hazard is estimated based upon the geologic and geomorphic setting. While each of the independently operated facilities is estimated to have one or both hazards, the probability of those hazards occurring at all of them but Los Medanos is lower than for the other facilities, because ground shaking is estimated to be lower. Figure 1.2-17 shows the SHZs at the facilities for which they have been mapped.

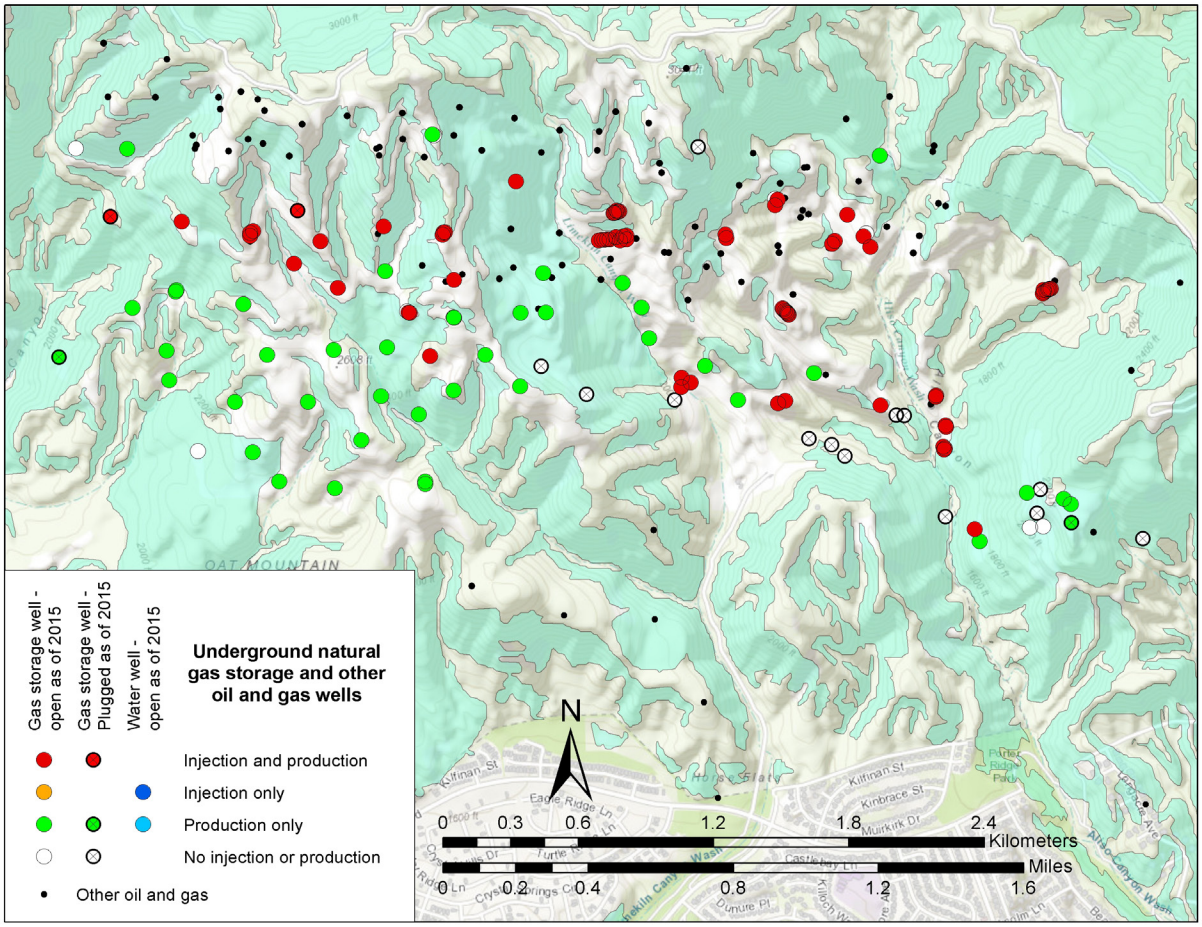
Table 1.2-4. UGS surface infrastructure in Seismic Hazard Zones by facility and type of zone.

	Facility	Infrastructure	Seismic Hazard Zone	
			Liquefaction	Earthquake-induced landslide
Independents	Gill Ranch Gas	All	? (unmapped, but includes alluvium by a river)	No (unmapped, but little topographic relief)
	Kirby Hill Gas	All	? (unmapped, but includes alluvium by a slough)	? (unmapped, but includes hillslopes)
	Lodi Gas	All	? (unmapped, but includes alluvium by a slough)	No (unmapped, but little topographic relief)
	Princeton Gas	All	? (unmapped, but includes alluvium by a river)	No (unmapped, but little topographic relief)
	Wild Goose Gas	All	? (unmapped, but includes alluvium by a river)	No (unmapped, but little topographic relief)
PG&E	Los Medanos Gas	All	No (unmapped, but no alluvium or shallow saturation)	? (unmapped, but includes hillslopes)
	McDonald Island Gas	All	? (unmapped, but includes alluvium by a slough)	No (unmapped, but little topographic relief)
	Pleasant Creek Gas	All	? (unmapped, but includes alluvium by a river)	No (unmapped, but little topographic relief)
SoCalGas	Aliso Canyon1	Well(s) and flowline(s)	No	Yes
		Plant	No	No
		Interconnect	Yes	Yes
	Honor Rancho2	Well(s) and flowline(s)	Yes	Yes
		Plant	Yes	No
		Interconnect	Yes	No
	La Goleta Gas	All	? (unmapped, but includes alluvium by a slough and shore)	? (unmapped, but includes bluffs)
	Playa del Rey3	Well(s) and flowline(s)	Yes	Yes
		Plant	Yes	Yes
		Interconnect	Yes	No

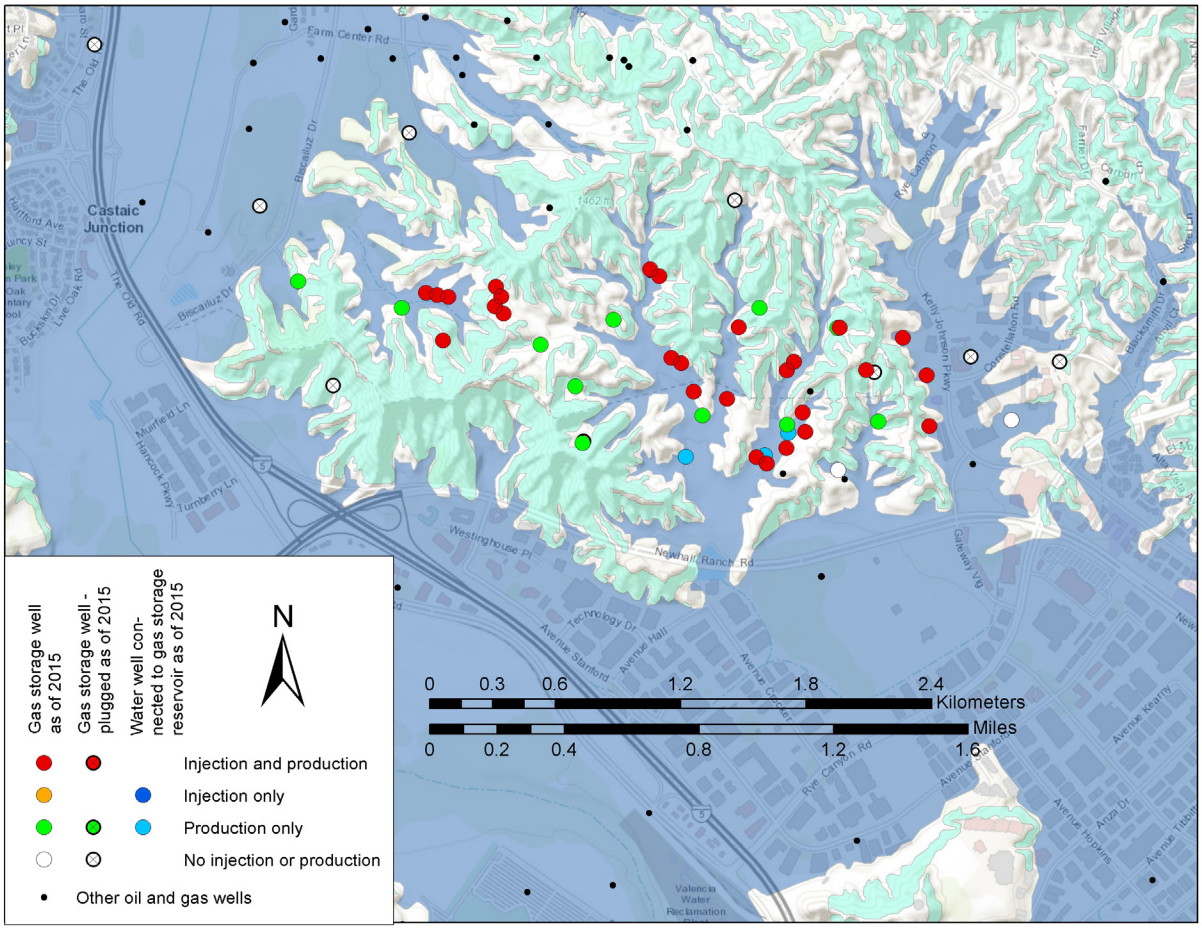
1 CGS (1998b);

2 CGS (1998a);

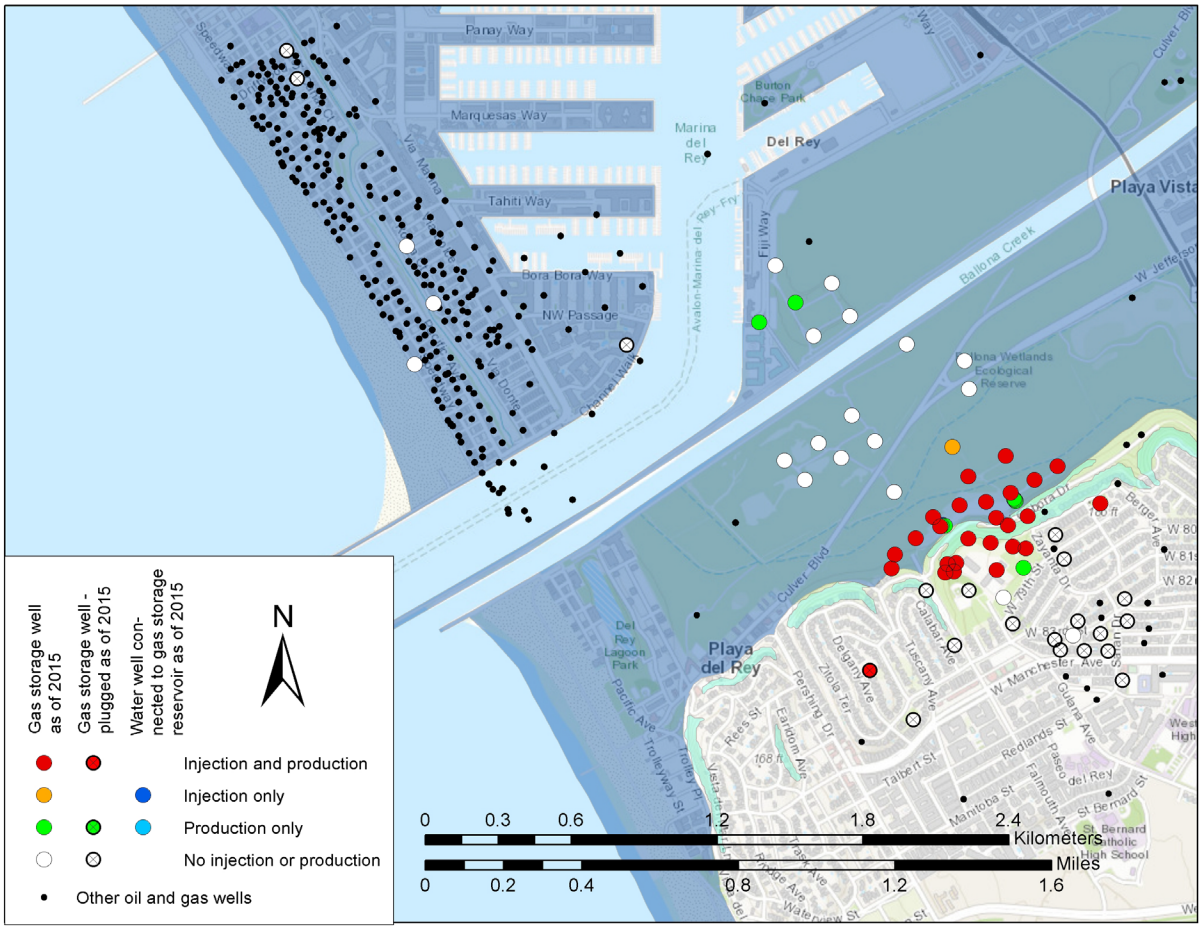
3 CGS (1995a,b)


Gas storage well - open as of 2015
Gas storage well - Plugged as of 2015
Water well - open as of 2015
Underground natural gas storage and other oil and gas wells
Injection and production
Injection only
Production only
No injection or production
Other oil and gas
N
0 0.3 0.6 1.2 1.8 2.4 Kilometers
0 0.2 0.4 0.8 1.2 1.6 Miles
OAT MOUNTAIN

(a)


Gas storage well as of 2015
Gas storage well - plugged as of 2015
Water well con-nected to gas storage reservoir as of 2015
N
Injection and production
Injection only
Production only
No injection or production
Other oil and gas wells
0 0.3 0.6 1.2 1.8 2.4
Kilometers
0 0.2 0.4 0.8 1.2 1.6
Miles
Castaic Junction
Farm Center Rd
Biscailuz Dr
The Old Rd
Live Oak Rd
Buckskin Dr
Hartford Ave
Muirfield Ln
Hancock Pkwy
Turnberry Ln
Westinghouse Pl
Newhall Ranch Rd
Technology Dr
Avenue Stanford
Avenue Hall
Avenue Crocker
Rye Canyon Rd
Kelly Johnson Pkwy
Constellation Rd
Gateway Vlg
Blacksmith Dr
Avenue Kearny
Avenue Hopkins
Anza Dr
Valencia Water Reclamation

(b)



(c)

Figure 1.2-17. Seismic Hazard Zones at the (a) Aliso Canyon (CGS, 1998b), (b) Honor Rancho (CGS, 1998a), and (c) Playa del Rey (CGS, 1995b) facilities. Liquefaction Zones shown in dark blue tint and Earthquake-Induced Landslide Zones in light blue tint.

UGS incidents arising from earthquake activity are not entirely hypothetical. The following text is from the Supplement to SoCalGas' Storage Risk Management Plan #2 (SoCalGas, 2016b):

> *"The 1994 Northridge earthquake damaged the surface terrain at the Aliso Canyon facility, including landslides, cracked well cellars and roads, tank farm damage, and pipe support damage. An immediate investigation of storage well integrity following the earthquake indicated that only one well -SS4-O- was affected, and it experienced a collapsed casing in a section above the gas storage zone. A work-over rig repaired the damaged well and, with regulatory oversight provided by DOGGR, SoCalGas successfully drilled around the damaged section and placed abandonment cement below the collapse and into the storage zone. SoCalGas recovered a section of the casing*

> *and noted that the collapsed casing sealed the well. The well was subsequently plugged in accordance with DOGGR plug and abandonment regulations.*
>
> *Since the 1994 Northridge earthquake, there have been no incidents of casing failure from seismic events at the Aliso Canyon facility."*

The reported sealing of the well by the collapsed casing suggests that no LOC occurred during this incident. Regardless, in other scenarios, wells could fail in ways that lead to LOC, and certainly surface infrastructure is vulnerable to damage. Therefore, UGS facilities in California should assess seismic hazard with respect to shaking and fault displacement and implement mitigation measures such as base isolation for foundations, seismic bracing, automatic seismic shut-off valves, etc.

SoCalGas is currently conducting a comprehensive hazard and risk assessment for the Aliso Canyon facility employing state-of-the art methodologies (Harris et al., 2017). The probabilistic seismic (ground shaking) hazard analysis (PSHA) utilizes the same technique used by CGS and USGS to develop the seismic hazard maps described above, but on a site-specific basis. This assessment is based on data for all relevant fault sources in the UCERF3 database, with extensive additional detailed characterization of faults within the facility and in its immediate vicinity. Estimates of local amplification of ground shaking caused by differences in surface geology at locations within the site are included in the analysis. A probabilistic fault displacement hazard assessment (PFDHA) is being carried out employing an analysis approach developed for other critical facilities adapted to include subsurface fault displacement. The PFDHA as applied at Aliso Canyon utilizes the fault characterizations developed for the PSHA and estimates of fault slip derived from earthquake magnitudes. The fault geometries and slip rates that form the inputs to these assessments are usually subject to significant uncertainties, often stemming from alternative interpretations of sparse available data. Therefore, an important aspect of both PSHA and PFDHA is rigorous treatment of these uncertainties to enable realistic uncertainty bounds on the hazard to be estimated.

The landslide hazard at Aliso Canyon is being addressed by extensive field investigations of existing and potential landslide zones. These include both surface mapping and gathering data from purpose-designed trenches to characterize and date recurring landslide events. Comprehensive structural geology, and petrophysical and geomechanical analyses are being conducted to provide the basis for assessment of risks, including gas leakage through faults and well failure. Although most sites are not subject to all of the hazards considered at Aliso Canyon, specific items from the suite of investigations being carried out there can serve as models for application to other UGS facilities.

1.2.3.8 Tsunami

1.2.3.8.1 Introduction

Tsunamis are sea waves generated by large displacements of water that can cause rapid inundation, followed by outwash, and related damage to low-lying coastal areas. In California, tsunamis can be caused by (1) distant and local earthquakes, and (2) by subsea landslides (Thio et al., 2010; Dooher, 2016). The force of water in the sea wave itself, or insofar as it can carry heavy debris capable of crashing into surface infrastructure, can cause catastrophic damage to UGS components such as pipelines, wellheads, compressors, etc. As such, the main mode of failure of concern for UGS sites is damage by impact from water or heavy debris on pipelines, wellheads, and other surface infrastructure. A secondary mode of failure is erosion and/or undermining of support structures and foundations holding surface infrastructure.

The UGS facilities in California that are vulnerable to marine tsunamis are the La Goleta and Playa del Rey facilities, located in Goleta (approx. 10 mi (16 km) from Santa Barbara) and Playa del Rey (near Venice Beach), as shown on Figure 1.2-18. Some of the wells and flowlines in the La Goleta UGS facility are within the projected inundation zone. The only facilities within the inundation zone at the Playa del Rey facility are in a few wells in Venice Beach north of the Ballona Creek estuary, which flows into the Pacific. These wells were open in 2015, but no gas was transferred through them in the 2006 through 2015 study period, suggesting they are observation wells. As such, they may not have flowlines connected, or, if present, the lines may not be charged with gas. However, these wells presumably connect to the storage reservoir, and so damage to them by a tsunami could potentially result in an LOC incident.

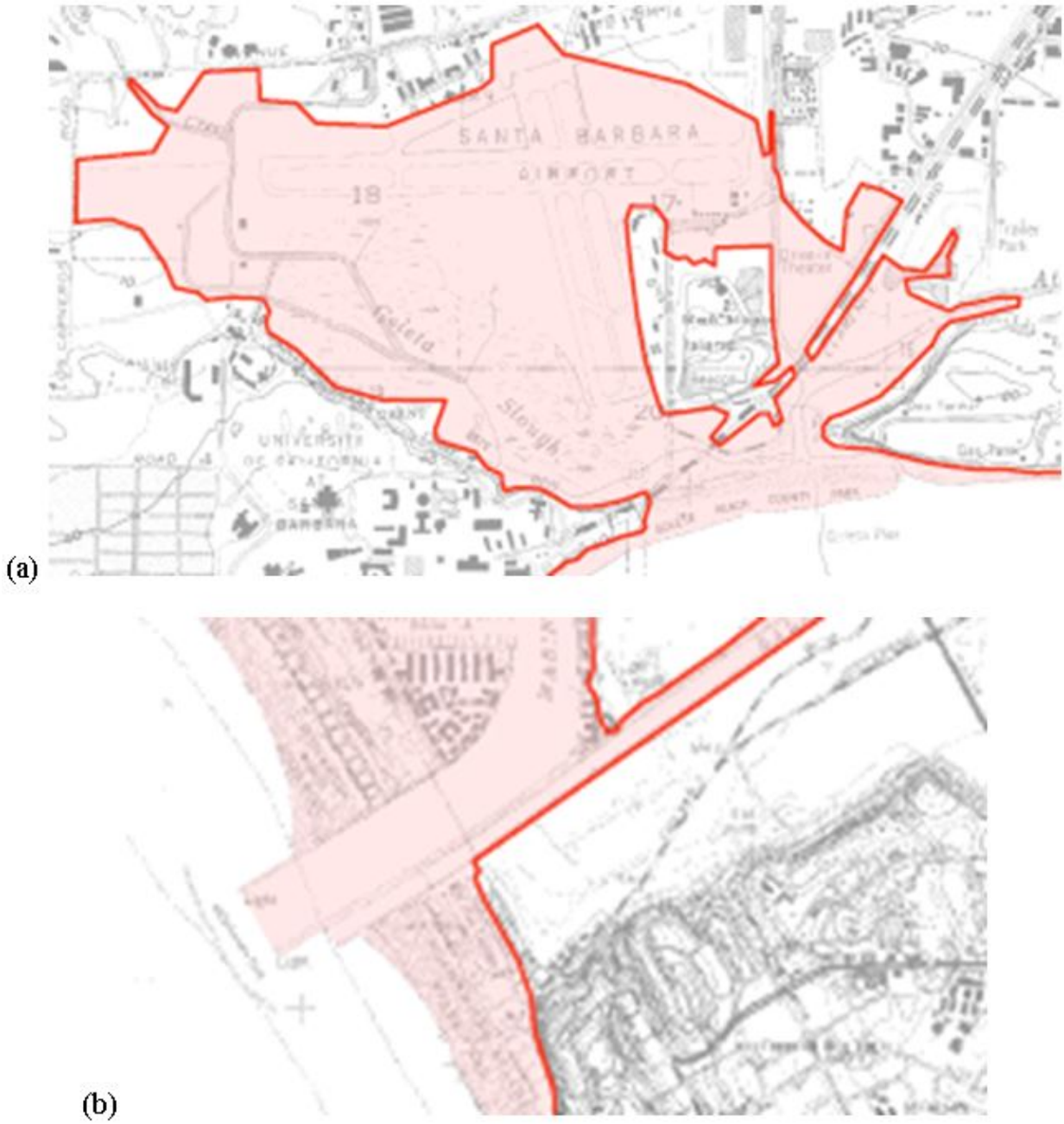


Figure 1.2-18. Maps showing potential tsunami inundation areas in pink for emergency planning: a) covering the La Goleta facility, which stretches from on bluffs east of the tsunami inlet to the bluffs west of the tsunami inlet (California Emergency Management Agency [CEMA] et al., 2009a), and (b) covering the Playa del Rey facility, whose surface facilities are primarily south of the channel near the bluffs (CEMA et al., 2009b).

1.2.3.8.2 Seismically Generated Tsunamis

Thio et al. (2010) used computational approaches to model seismically generated tsunamis along the Central California coast with consideration of both aleatory uncertainty (random uncertainty that generally cannot be reduced) and epistemic uncertainty (uncertainty related to properties that can be reduced by data collection and better understanding). Results of their modeling relevant to the La Goleta and Playa del Rey UGS facilities are shown in Figure 1.2-19 in plots of frequency of tsunamis of given waveheights for cities of Santa Barbara and Venice, California, respectively. The blue curves represent the hazard curve including aleatory uncertainty, while the red curves assume no aleatory uncertainty. As shown, seismically generated tsunamis with waveheights of 1 m and 2 m have return periods of approximately 200 and 1,000 yrs, respectively. We note that floating debris carried by the tsunami are a hazard of tsunami flooding because of the threat of physical impact to wellheads and related UGS infrastructure.

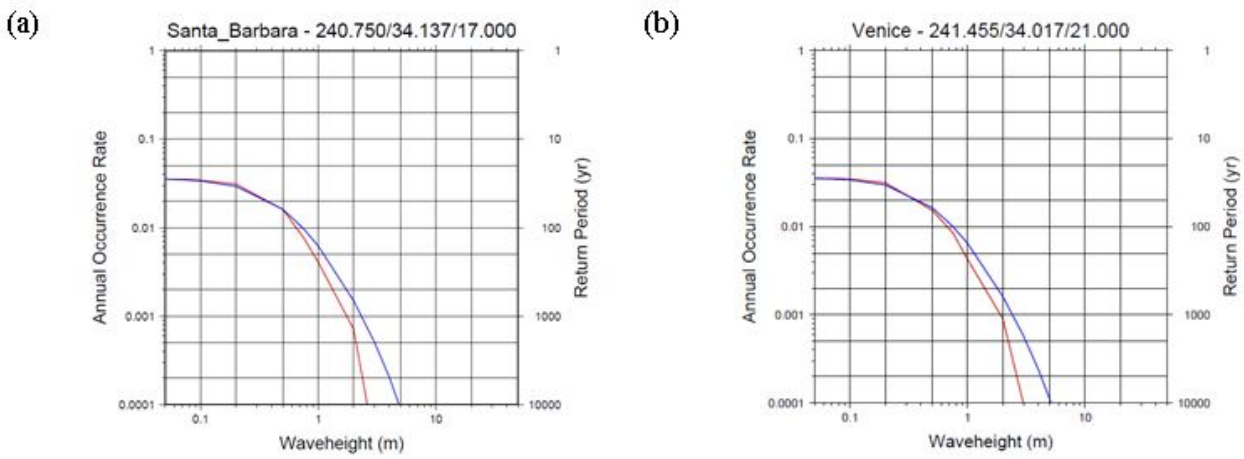


Figure 1.2-19. Modeled results of seismically generated tsunami waveheight frequency for Santa Barbara and Venice, California. A 1 m waveheight tsunami is predicted to have a recurrence interval (return period) of approximately 200 yrs.

1.2.3.8.3 Submarine Mass Failure Tsunamis

Dooher (2016) presented results of the analysis of tsunamis generated along the Central California coast by submarine mass failures (a.k.a. submarine landslides). Bathymetric mapping of the seafloor along the coast of the Santa Lucia escarpment, along with seismic reflection and core studies, allow the dating of subsea landslides. Onshore geologic evidence of tsunamis and historical records complement the offshore studies to produce defensible predictions of tsunami hazard. Shown in Figure 1.2-20 is a map of the Central California

coast from Dooher (2016) showing estimated waveheights from various submarine mass failures (in red) along with official NOAA records of historical tsunami-related runups. Note that in 1812, there was a runup in Gaviota, approximately 23 mi (37 km) west of Goleta. Note further that NOAA records an official wave runup height of 8.2 ft (2.5 m) at Goleta.

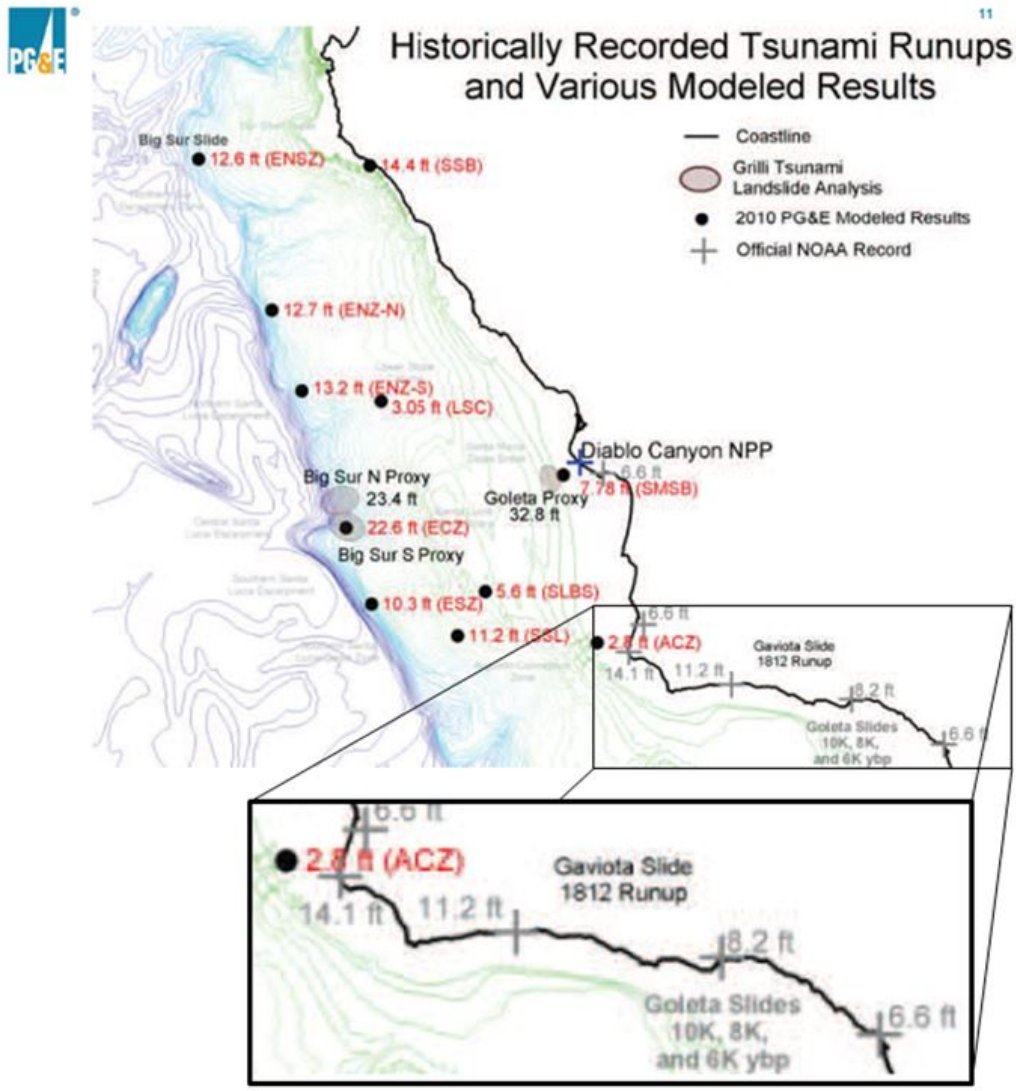


Figure 1.2-20. Historical and modeled results of tsunamis along the Central California coast after Dooher (2016). Note the 8.2 ft official NOAA record of runup at Goleta.

1.2.3.9 Flooding

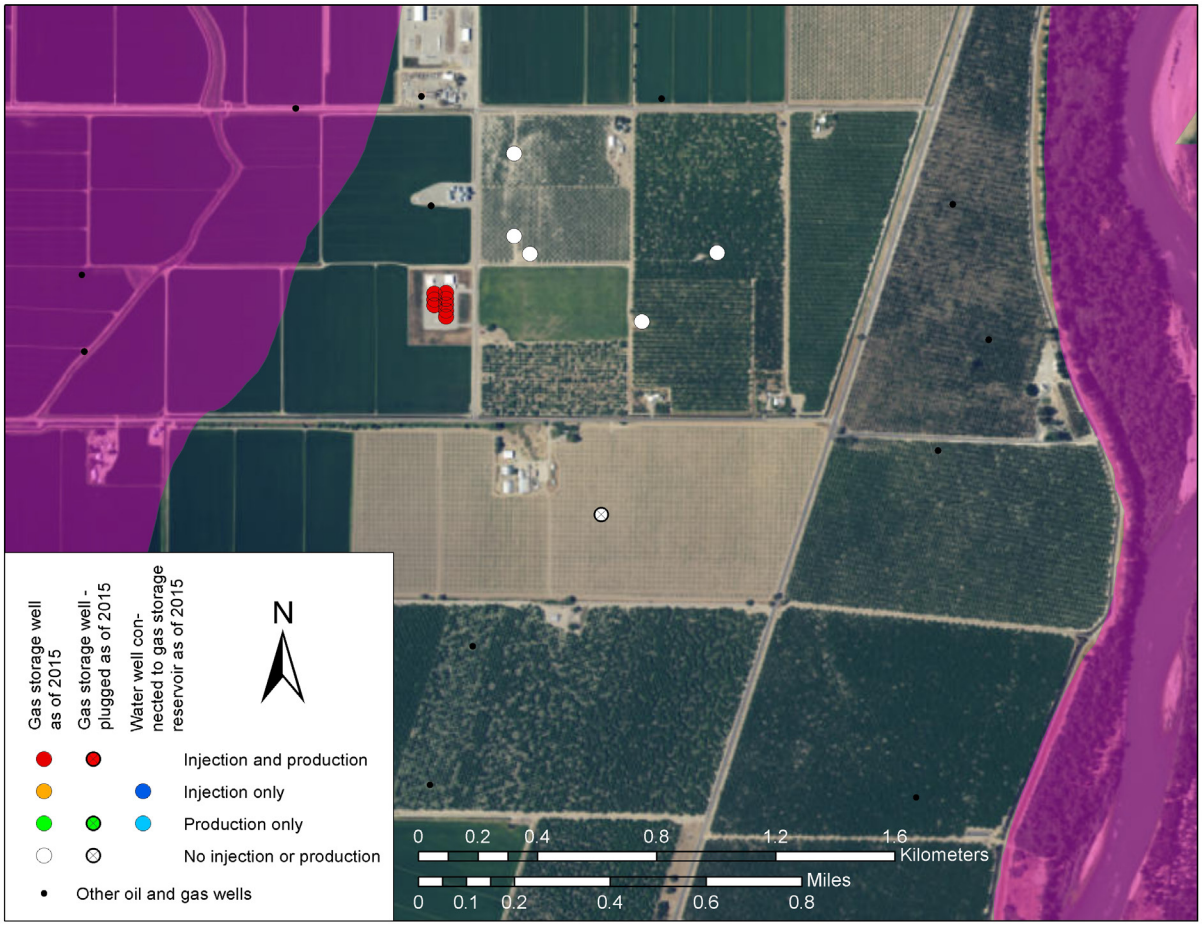
While the facilities with substantial topographic relief are generally subject to landslide hazard, facilities with little topographic relief potentially are subject to substantial risk of flooding. Like tsunamis, floods can damage UGS surface infrastructure through impact by entrained debris and erosion. Flooding also can result in a longer period of submergence than tsunamis, cutting off or making difficult access to valves and other controls. This can interfere with a facility's ability to meet its purpose serving demand, even if no other damage occurs.

The Federal Emergency Management Agency (FEMA) maps predicted flood frequency. Table 1.2-5 lists the type of infrastructure in each facility that resides within areas with an estimated 1% annual probability of flooding. We note that these maps are known to underestimate the extent of this risk. For instance, they do not consider changing hydraulics and hydrology due to development nor changing precipitation patterns and sea level due to climate change (Highfield et al., 2013).

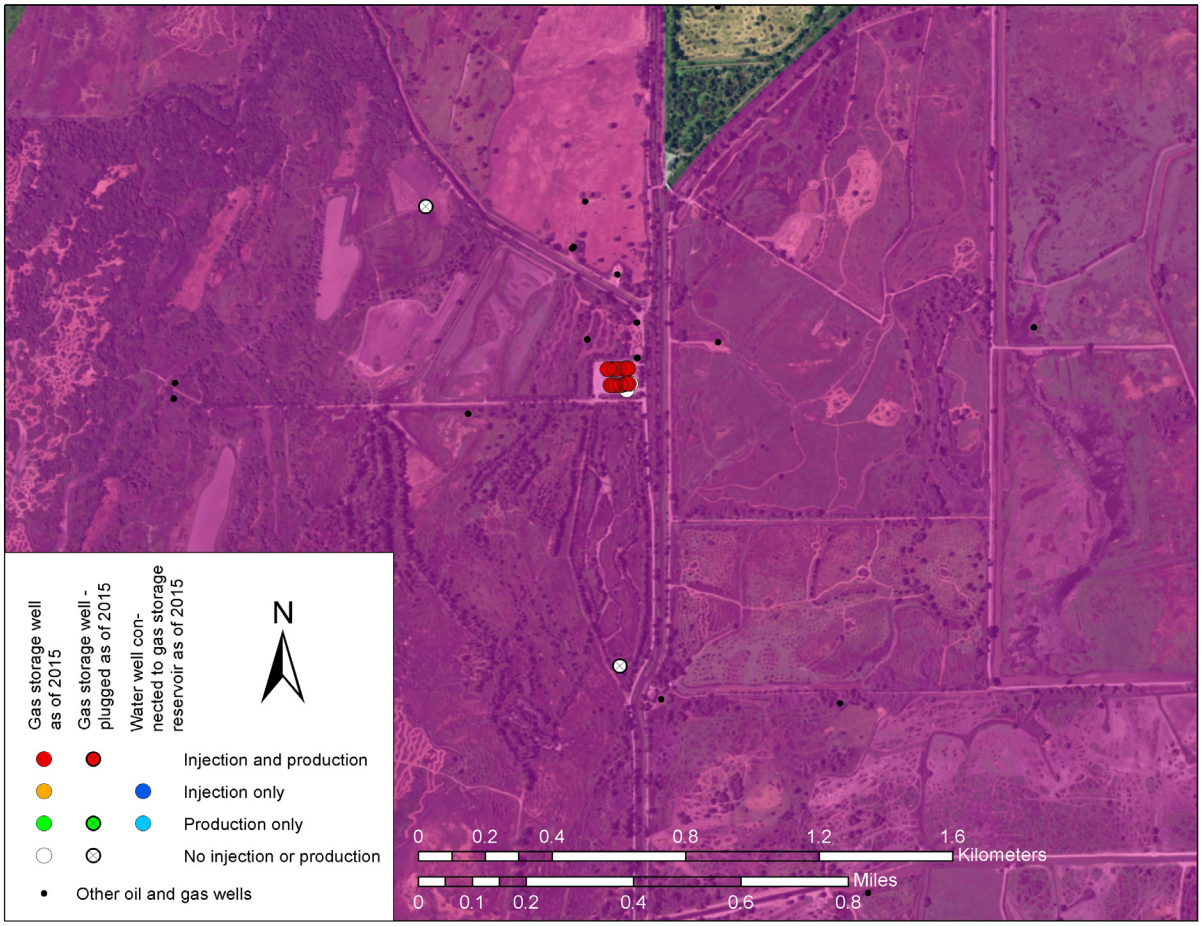
Table 1.2-5. UGS surface infrastructure in areas with an estimated 1% annual probability of flooding.

	Facility	Well(s) and flowline(s)	Plant	Interconnect	Source
Independents	Gill Ranch Gas[1, 2]	No	No	Yes	[1]FEMA (2016a) [2]FEMA (2017a)
	Kirby Hill Gas[3]	No	No	Yes	[3]FEMA (2016b)
	Lodi Gas[4, 5]	No	No	Yes	[4]FEMA (2017b) [5]FEMA (2016c)
	Princeton Gas[6]	No	Yes	Yes	[6]FEMA (2015)
	Wild Goose Gas[7]	Yes	No	Yes	[7]FEMA (2011)
PG&E	Los Medanos Gas[8]	No	No	No	[8]FEMA (2017c)
	McDonald Island Gas[4, 8]	Yes	Yes	Yes	[4]FEMA (2017b) [8]FEMA (2017c)
	Pleasant Creek Gas[9]	No	No	No	[9]FEMA (2017d)
SoCalGas	Aliso Canyon[10]	No	No	No	[10]FEMA (2016d)
	Honor Rancho[10]	No	No	No	[10]FEMA (2016d)
	La Goleta Gas[11]	Yes	No	No	[11]FEMA (2016e)
	Playa del Rey[10]	No	No	No	[10]FEMA (2016d)

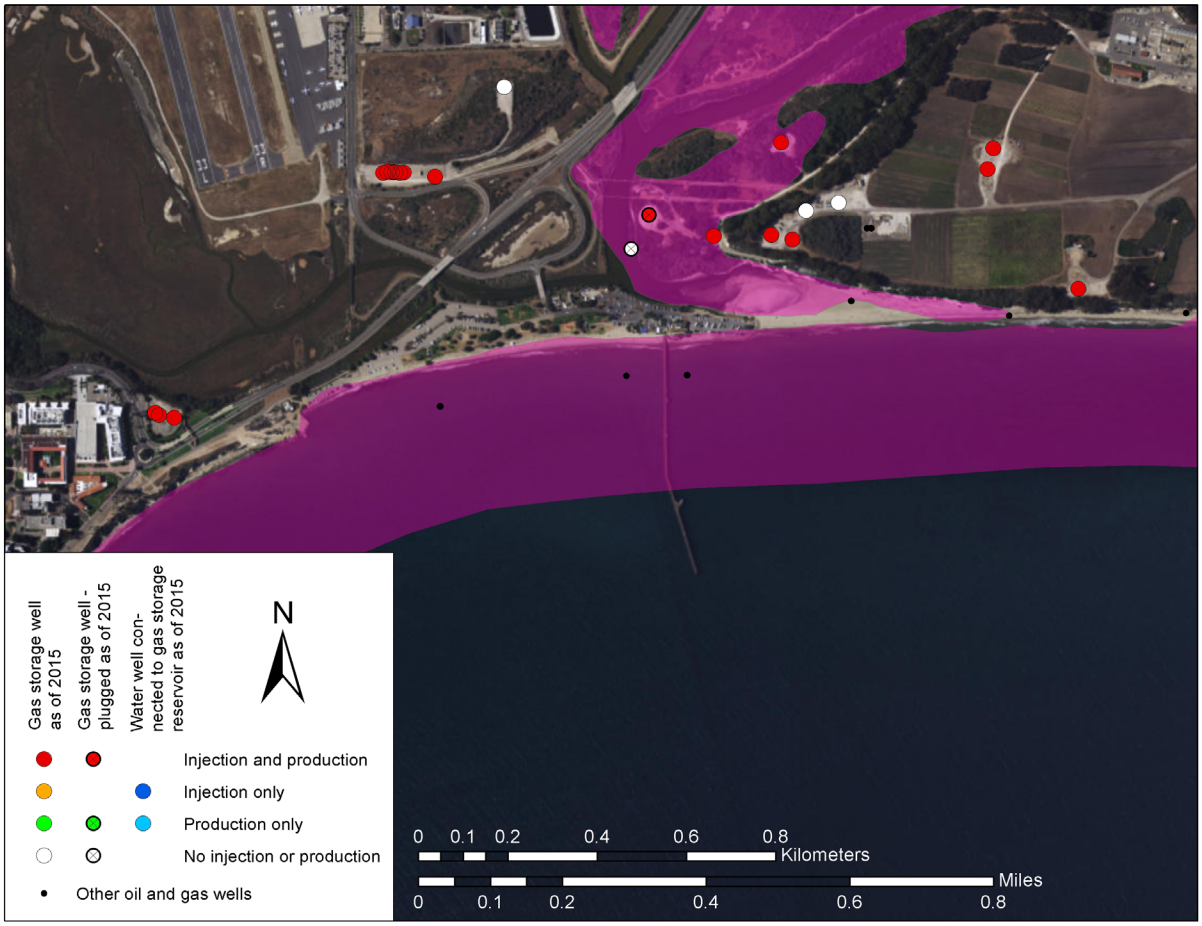
The 1% annual probability flood zones are shown on Figure 1.2-21 for facilities with well(s), flowline(s), or plant(s) in the zone other than McDonald Island. McDonald Island is not shown because it is entirely in a flood zone along with the surrounding area. This being so, most of the plant infrastructure at McDonald Island are all on elevated platforms to reduce the risk of flooding. Also of note, only an apparently unoccupied and relatively small portion of the plant at the Princeton Gas facility is in this flood zone, as shown in Figure 1.2-21a.


Gas storage well as of 2015
Gas storage well - plugged as of 2015
Water well connected to gas storage reservoir as of 2015
N
Injection and production
Injection only
Production only
No injection or production
Other oil and gas wells
0 0.2 0.4 0.8 1.2 1.6
Kilometers
Miles
0 0.1 0.2 0.4 0.6 0.8

(a)


Gas storage well as of 2015
Gas storage well - plugged as of 2015
Water well con-nected to gas storage reservoir as of 2015
N
Injection and production
Injection only
Production only
No injection or production
Other oil and gas wells
0
0.2
0.4
0.8
1.2
1.6
Kilometers
Miles
0
0.1
0.2
0.4
0.6
0.8

(b)



(c)

Figure 1.2-21. Select facilities partially in zones with a 1% annual probability of flooding according to FEMA: (a) Princeton Gas (FEMA, 2015), (b) Wild Goose Gas (FEMA, 2011), and (c) La Goleta Gas (FEMA, 2016e). Flooding zones shown in a purple tint. Note the plant at Princeton Gas (a.k.a. Central Valley Gas) is located north of the well field. The northwest corner of the plant site is within the flood zone.

1.2.3.10 Sea-level Rise

Sea level is predicted to rise along the California coast at La Jolla by ~5-7 in (12-18 cm) by 2030, and by ~8.4-14 in (21-37 cm) by 2050 relative to the 1991-2009 mean sea level, as shown in Figure 1.2-22 (Griggs et al., 2017). Flooding caused by sea-level rise is a hazard for the low-lying UGS sites in California, which include La Goleta, Playa del Rey, and McDonald Island. Given that all of these sites currently mitigate against flooding, global

sea-level rise is not expected to be a major risk factor for UGS in California through 2050. Projections for beyond 2050 are more uncertain, but clearly raise the possibility that much more extensive mitigations will be necessary to operate the four low-lying facilities.

Feet above 1991-2009 mean	MEDIAN	LIKELY RANGE	1-IN-20 CHANCE	1-IN-200 CHANCE
Year / Percentile	*50% probability SLR meets or exceeds...*	*67% probability SLR is between...*	*5% probability SLR meets or exceeds...*	*0.5% probability SLR meets or exceeds...*
2030	0.5	0.4 — 0.6	0.7	0.9
2050	0.9	0.7 — 1.2	1.4	2.0
2100 (RCP 2.6)	1.7	1.1 — 2.5	3.3	5.8
2100 (RCP 4.5)	2.0	1.3 — 2.8	3.6	6.0
2100 (RCP 8.5)	2.6	1.8 — 3.6	4.6	7.1
2100 (H++)	10			
2150 (RCP 2.6)	2.5	1.5 — 3.9	5.7	11.1
2150 (RCP 4.5)	3.1	1.9 — 4.8	6.5	11.8
2150 (RCP 8.5)	4.3	3.0 — 6.1	7.9	13.3
2150 (H++)	22			

Figure 1.2-22. Forecasted sea-level rise relative to 1991-2009 mean for various times in the future. As shown, the most likely projected sea-level rise for California for 2030 ranges from 0.4-0.6 ft (12-18 cm) and approximately twice this for 2050 (Griggs et al., 2017).

1.2.3.11 Land Subsidence

Land subsidence is a well-recognized threat to infrastructure such as pipelines (e.g., Baum et al., 2008) and wells (e.g., Bruno, 2001), making it a substantial hazard for UGS surface and subsurface systems. Land subsidence in California occurs by loss of porosity and/or rearrangement of clastic sediments due typically to groundwater withdrawals, and in the California Delta region by oxidative decomposition of peat and other organic matter as a result of reclamation of wetlands and related drying (Rojstaczer et al., 1991). The modes of failure that occur as a result of land subsidence include shearing and buckling of wells, cracks, and displacement of surface infrastructure that can rupture flowlines and lead to LOC. Land subsidence is common in California's San Joaquin Valley, Delta, and Sacramento Valley areas. As such, land subsidence is a hazard to the Gill Ranch, Lodi, McDonald Island, Wild Goose, and Central Valley Storage facilities.

1.2.3.12 Wildfire

Wildfires are a serious hazard for the surface infrastructure at UGS facilities in California, regardless of whether the fire is started at the site by activities or incidents associated with the facility (e.g., welding, or ignition of released natural gas) or whether they were started externally by any cause and burn into the footprint of any UGS facility infrastructure. Several of California's UGS facilities are located in areas of grass and brush that become very dry in the summer and early fall. There are also dry northeasterly winds in California (so-called Santa Ana winds) that periodically blow particularly in southern California, causing severe fire hazard because of their typically low humidity.

Although the aboveground flowlines, wellheads, and related noncombustible hardware spread around UGS facilities will likely withstand grassfires because they are relatively fast moving and grass does not provide a lot of fuel, standard practice is to establish and maintain breaks in all vegetation around aboveground pipes and wellheads, and to maintain space between buildings and surface infrastructure. Bare ground and open spaces provide both protection for the pipe from heat impacts of direct or indirect contact with burning vegetation, and it also provides defensible space for firefighters to protect vulnerable infrastructure. Because fire of any kind is such an obvious hazard at UGS facilities, existing compressors, gas processing, and/or power plants at UGS facilities in California are located on pads maintained devoid of vegetation and with buffer zones around the perimeter. Practical and useful wildfire information related to oil and gas infrastructure can be found in the document, "READY, SET, GO! For Oil and Natural Gas Operations" http://vcfd.org/images/ready-set-go/Ready_Set_Go_Oil__Gas_2013_sm.pdf (accessed 7/25/17).

The California Department of Forestry and Fire Protection (Cal Fire) has mapped fire hazard severity zones in its area of jurisdiction throughout the state, and has also drafted or recommended such zones for selected areas where local fire agencies are responsible for non-urban areas. Table 1.2-6 lists the predominant and maximum fire-hazard severity zone at each type of surface infrastructure.

Table 1.2-6. Predominant (and maximum, if different) fire hazard severity zones for each type of surface infrastructure at each UGS facility in California from Cal Fire (2007a) and selected local responsibility areas indicated in the footnotes. Pink tint indicates moderate hazard and red indicates very high hazard (no areas of high hazard predominated for any type of infrastructure in any facility).

	Facility	Well(s)	Flowline(s)	Plant	Interconnect	Source
Independents	Gill Ranch Gas[1, 2]	Not zoned	Not zoned	Not zoned	Not zoned (moderate)	[1]Cal Fire (2007b) [2]Cal Fire (2007c)
	Kirby Hill Gas[3]	Moderate	Moderate	Moderate	Moderate	[3]Cal Fire (2007d)
	Lodi Gas[4, 5]	Not zoned	Not zoned (moderate)	Not zoned	Not zoned (moderate)	[4]Cal Fire (2007e) [5]Cal Fire (2007f)
	Princeton Gas[6]	Not zoned	Not zoned	Not zoned	Not zoned (moderate)	[6]Cal Fire (2007g)
	Wild Goose Gas[7]	Not zoned	Not zoned (moderate)	Not zoned	Not zoned (moderate)	[7]Cal Fire (2007h)
PG&E	Los Medanos Gas	Moderate	Moderate	Moderate	Moderate	
	McDonald Island Gas[4, 8]	Moderate	Moderate	Not zoned	Not zoned (moderate)	[4]Cal Fire (2007e) [8]Cal Fire (2007i)
	Pleasant Creek Gas[9]	Moderate	Moderate	Moderate	Moderate	[9]Cal Fire (2007j)
SoCalGas	Aliso Canyon[10]	Very high	Very high	Very high	Very high	[10]Cal Fire (2011)
	Honor Rancho[10]	Very high	Very high	Very high	Very high	[10]Cal Fire (2011)
	La Goleta Gas[11]	Not zoned	Not zoned	Not zoned	Not zoned	[11]Cal Fire (2007k)
	Playa del Rey[10]	Very high	Very high	Very high	Not Zoned (Very high)	[10]Cal Fire (2011)

The facilities in southern California are in the highest fire hazard severity zones as a group. In contrast, PG&E's facilities are mostly in moderate fire hazard severity zones, and the independent facilities are primarily not in a fire-hazard severity zone. These differences generally correlate to whether wild vegetation exists in the vicinity, and if so, whether it consists of grasslands or vegetation with higher fuel density, such as chaparral or forest.

1.2.3.13 Linkages Between Failure Modes

As shown in Figure 1.0-1, containment of high-pressure gas in UGS relies on an integration of components into a system. As with any system, failure of one component can lead to failure(s) of other components. In the bulleted list below, we detail some examples of modes of failure for wells (Figure 1.2-23) and for reservoirs (Figure 1.2-24) that are coupled and strongly linked. Specific examples of linked failure modes have been documented in the literature (e.g., Evans, 2009; Folga et al., 2016). This list highlights the importance of maintenance and testing of every component in order to ensure integrity of the whole UGS system at each facility.

Loss of Well Integrity:

- **Injection/Withdrawal through Tubing/Packer** – Failure of tubing or packer and tubing is plugged (assumes no surface or subsurface safety valve functioning and in place) – Pressurized gas migration into annular space – Corrosion of production casing causes loss of well integrity (hole) in uncemented or poorly cemented section of production casing – Pressurized storage gas migrated through hole in production casing and into uncemented annular space – Gas migrates upwards in borehole and gas pressure exceeds breakdown pressure of surface casing seat/shoe – Gas migrates around surface casing and then enters lower pressure aquifers and/or breaksout (fractures) as an uncontrolled release at the surface (breach blowout).

- **Injection/Withdrawal through Casing Only (Casing Injection)** – Failure of integrity of the production casing due to corrosion (assumes no surface or subsurface safety valve functioning and in place) – Pressurized gas migration into uncemented or poorly cemented annular space - Gas migrates upwards in borehole and gas pressure exceeds breakdown pressure of surface casing seat/shoe – Gas migrates around surface casing and then enters lower pressure aquifers and/or induced fractures as an uncontrolled release at the surface.

- **Well Work-over or Plugging and Abandoned Operations** – Well is "killed" with heavy brine or mud (assumes wellhead is not configured to work under pressure) to alleviate gas storage pressure – Wellhead is disassembled for installation of blowout preventers (BOPs) – Prior to installation of BOPs, well "kicks" due to under balance of "kill" fluids and there is an immediate uncontrolled release through the well at the surface.

- **Plugging and Abandonment Well Release** – Well has been permanently plugged and abandoned – Subsurface mechanical plug or cement plug(s) fail – Gas migrates out of storage reservoir and enters shallower porous and permeable geologic formations – Gas invasion into shallower oil and gas production or disposal wells and impacts operations or gas invasion into other abandoned or improperly plugged wells - Potentially breaks out at the surface and/or migrates into aquifers.

- **Seismic Activity** – Strong enough earthquake that damages wellbore and allows for uncontrolled release at the surface (assuming no surface or subsurface safety valve functioning and in place).

- **Wellhead Damage** – Damage to wellhead (accidental or intentional) – Severe enough damage to allow for uncontrolled release without ability to shut in well (assuming no surface or subsurface safety valve functioning and in place).

Figure 1.2-23. Linkages between well integrity failure modes.

Loss of Reservoir Integrity (breaches in horizontal or vertical seal containment):

- **Overpressurization of Gas Storage Reservoir** – Injection pressures exceed pressure limits of confining zone/interval – Gas migrates out the storage reservoir into shallower porous and permeable geologic formations – Pathways may include migration to other shallower, producing oil and gas wells, disposal wells, or migration into abandoned or improperly plugged wells – Gas migration could reach the surface or into aquifers.

- **Overfilling of the Gas Storage Reservoir** – Gas storage reservoir is overfilled and exceeds the spill point or geologic trapping mechanism of the formation being utilized for gas storage – Gas migrates out of the storage reservoir and finds pathways into abandoned or improperly plugged wells or other oil and gas producing horizons – Potentially breaks out at the surface or migrates into aquifers.

- **Third-Party Damage to Gas Storage Reservoir** – Artificial penetration into or through the gas storage reservoir by third-party operator during drilling or plugging operations – Uncontrolled release of gas at the third-party wellhead due to overpressurization and/or inadequate well control measures at the surface.

Figure 1.2-24. Linkages between reservoir integrity failure modes.

We present in Figure 1.2-25 a fault tree representation of the first linked scenario in Figure 1.2-23. As shown, fault trees make use of AND and OR gates to graphically depict the linkages of various features, events, and processes (FEPs) in a failure scenario. The likelihood of the top event can be calculated using knowledge of the likelihoods of each of the contributing events and the logic of the AND and OR gates (e.g., Vesely et al., 1981; Oldenburg and Budnitz, 2016).

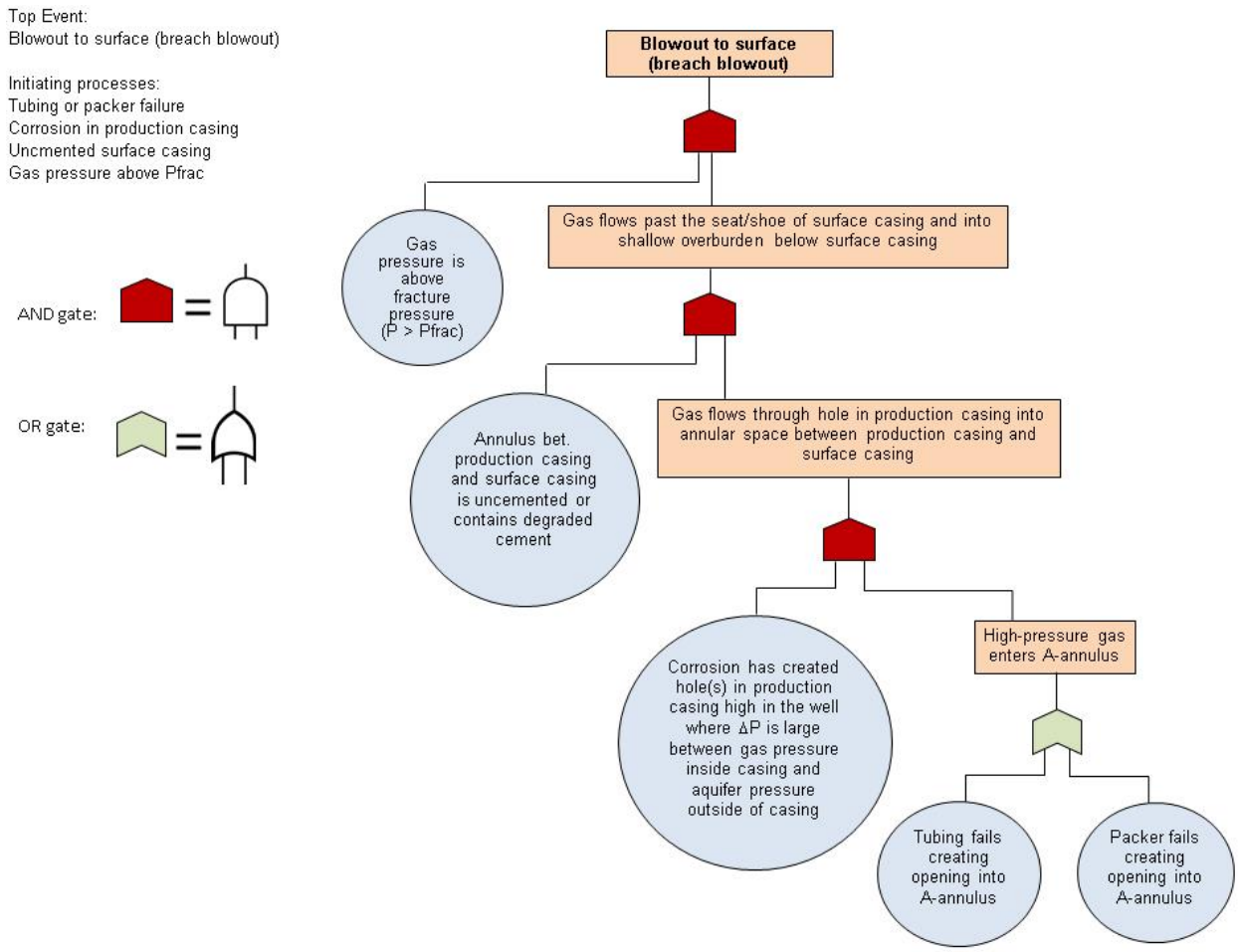


Figure 1.2-25. An example of a fault tree applicable to UGS wells in California depicting the initiating and contributing events to the top event (Blowout to surface) as described by words of the first item in the list of well-integrity failure linkages above.

1.2.4 Likelihood of Failure of UGS

Likelihood of failure can be estimated in various ways. Evans (2009), Folga et al. (2016), Schultz et al. (2017), and Evans and Schultz (2017) have used reported incidents and associated information on cause, field type, location, and mode to develop incident databases (catalogs) from which annual frequency of incidents per UGS facility, or per well, or per year of operation, or per any other combination of operating parameters one wants to use as a basis for frequency can be determined. We refer to the number of incidents in whatever classification(s) as the numerator, and the number of facilities, or number of wells, etc. as the denominator. Regardless of the details, the essence of the approach is to estimate annual frequency from the historical records of incidents. Annual frequency can be

converted to time to event by simply inverting the frequency. The main goal of this section is to discuss the estimate of the likelihood of incidents at California UGS facilities, which will require sampling from the various incident databases and estimates from the literature. We begin by describing historical records of UGS failures
to estimate time-to-event. Additional approaches to estimating failure likelihood will also be discussed.

1.2.4.1 History of UGS Loss-of-containment and Other Failures

1.2.4.1.1 Subsurface

Very significant and useful compilations of UGS incidents have been carried out by Evans (2009), Folga et al. (2016), Schultz et al. (2017), and Evans and Schultz (2017). Evans (2009) catalogued worldwide incidents for UGS for the various kinds of storage reservoirs, namely depleted hydrocarbon reservoir (DHR), Aquifer, Salt Cavern, and other subsurface storage types. Table 1.2-7 presents only the California incidents as a subset of the larger set of worldwide incidents catalogued by Evans (2009). All of the California UGS facilities are in depleted hydrocarbon reservoirs (DHR), although one reservoir interval at the DHR Kirby Hill facility is classified as aquifer storage (U.S. EIA, 2016), which may have led Evans (2009) to classify it as an aquifer storage facility. Every one of the incidents in Table 1.2-7 involves loss-of-containment (LOC) except apparently numbers (9) and (11), without evaluation or ranking by severity.

Table 1.2-7. California UGS incidents extracted from the list of worldwide UGS incidents compiled by Evans (2009). Note that Pleasant Creek was listed by Evans as an aquifer storage reservoir storage site, but we include it here as a DHR site. The numbers in parentheses in Column 6 correspond to the contributory processes (causes) enumerated in Table 1.2-9. The dark pink incidents are at facilities that are currently active UGS sites in California, while the light pink incidents are no longer active UGS facilities. The white rows are incidents that did not report loss-of-containment as a consequence of the incident. Note that the table says Montebello closed in 2003, but in fact injection and production continued until 2016 (see Section 1.1.3 of this report).

	Depleted Oil/Gasfield Storage					
	Facility	**Operator**	**Product**	**Date**	**Description of event/fatalities/injuries**	**Reported cause/comment (bracketed numbers = mechanism in Figure 5)**
Incidents involving casualties/evacuations						
1	Montebello, LA California, USA	SoCal	Gas	1950s-1980s	Storage gas lost over extended period. In 1980 found within housing estate above field - led to evacuation of families on many occasions	Storage gas migrated via old, poorly completed wells and possibly faults. Injection pressure higher than original oilfield pressure, causing fracture and damage to old wells. Injection ceased 1986, facility closed 2003. Improperly plugged wells requied re-abandonment (1, 5, 14)
Incidents where no casualties involved but financial or property loss or closure occurred						
2	Playa del Rey, LA, California, USA	SoCal	Gas	April 2003	25 minute release of gas with a fine mist of oil	Valve in compressor unit broke (2)
3	Castaic Hills & Honor Rancho, California, USA	SoCal	Gas	1975-present?	Gas migration from Castaic reservoir to adjacent fields & thence to surface	Gas migrated laterally to shallower Honor Rancho & Tapia structures, via faults and thence to surface, killing oak trees - affected oil production in nearby producing wells (1, 4, 12, 13, 14)
4	Playa del Rey, LA, California, USA	SoCal	Gas	1940s-present day	Migration of large amounts of stored gas	Stored gas has migrated from PDR structure into Venice structure from earliest days, connection between structures, some fault & well related (1, 5, 12, 14)
5	McDonald Island, Stockton, California, USA	Pacific Gas & Electric Co.	Gas	Oct 1993	Explosion, causing US $2 million damage	Explosion in moisture extraction (gas conditioning) plant (2)
6	McDonald Island, Stockton, California, USA	Pacific Gas & Electric Co.	Gas	1974	Explosion, fire burned for 19 days, 0.42 Mcm gas consumed	Not available (18)
7	East Whittier, California, USA	SoCal	Gas	1970s	Gas migrated from original injection site	Injected gas produced by other company, facility eventually closed in 2003 (4, 5, 12).
8	El Segundo, California	Not available	Gas and propane	Early 1970s	Gas migration -threatening housing development	Gas migration from reservoir to surface along fault planes. Facility initially shut in (pre 1993) but now abandoned for safety due to new housing (4, 5, 12, 13)
9	California, USA	Not available	Gas	Not available	Storage well damaged - crushed	Storage well damaged during earthquake (1, 17)
10	California, USA	Not available	Gas	Not available	Storage well damaged - casing shoe leak	Well inadvertently sidetracked during repair of casing shoe leak (1, 11)
11	California, USA	Not available	Gas	Not available	Corrosion of storage well casing	Well inadvertently sidetracked during repair of corroded casing (1, 11)
12	Pleasant Creek, California, USA	Not available	Gas	1972-1976	Soil gas surveys detect gas over storage area	Gas migrating up out of reservoir. Poor seal? (4, 12, 13)

As shown in Table 1.2-7, 12 incidents occurred in California out of 228 total incidents shown in Evans' original worldwide UGS incident table (Evans, 2009, Figure 6), but there were only 27 DHR incidents worldwide, which means California had almost half (12/27) of the reported worldwide DHR UGS incidents. This fact is discussed by Evans (2009) as possibly being explained by California's reliance on old wells and relatively lax U.S. and California regulation relative to worldwide UGS standards. It is important to note that only ten incidents in Table 1.2-7 involved reported LOC, and only eight LOC incidents were reported at facilities that are still being used for UGS in California. Nevertheless, with California having eight of the total 27 DHR LOC incidents, California apparently has a disproportionate number of LOC incidents relative to the worldwide average.

Among the 27 worldwide DHR incidents reported by Evans (2009), three are related to valves and other surface operations. Two had unknown causes. Therefore, 22/27 (81%) of the California LOC incidents are documented to be related to subsurface integrity (casing, seal, well control, etc.) failure. This proclivity toward incidents related to subsurface integrity also applies to aquifer storage in the data of Evans (2009), who reports 17/24 (71%) of the incidents are subsurface-integrity related.

1.2.4.1.2 Surface

Folga et al. (2016) updated and augmented the tables of Evans (2009), parts of which we presented in Table 1.2-7, by adding incidents taken from the PHMSA database. The comprehensive Folga et al. (2016) table that we have filtered to show only California UGS incidents is presented as Table 1.2-8. Note that there are only six facilities with incidents listed in the table that are still storing gas (Los Medanos, McDonald Island, Playa del Rey, Aliso Canyon, Honor Rancho, and Wild Goose). A total of 11 of the 13 incidents at sites still storing gas involve LOC. Approximately one-half of the LOC incidents in California were due to wells (7/16 incidents) and one-half (6/16) of the incidents in Table 1.2-8 were related to surface infrastructure.

Table 1.2-8. California-only portion of the table from Folga et al. (2016) that combines the Evans (2009) compilation with incidents from the PHMSA database to create a comprehensive list of 16 California UGS incidents. Note that El Segundo, East Whittier, and Montebello no longer store gas, leaving 13 incidents at existing UGS facilities. Note further that the first Aliso Canyon incident in the table, and the first Honor Rancho incident, did not involve LOC, leaving 11 LOC incidents. The failure mechanism ID's in column 8 are presented in Table 1.2-9.

Field Name	County Name	State	Current Operator	Date	Impacts	Reported Cause	Failure Mechanism ID	Source
Los Medanos	Contra Costa	CA	Pacific Gas and Electric Company	5/25/2011	No service has been lost.	During a scheduled hydrotest job, the valve stem on an inlet fire valve to a regulator station at 2445 Garcia Avenue in Mountain View broke at 1,745 hours. The valve was being operated to release water from the line. The valve was broken in the partially open position causing gas to escape.	2, 11	PHMSA
McDonald	San Joaquin	CA	Pacific Gas and Electric Company	10/1/1993	Explosion, causing $2 million damage.	Explosion in moisture extraction (gas conditioning) plant.	2	Evans and Chadwick, 2009
McDonald	San Joaquin	CA	Pacific Gas and Electric Company	1974	Explosion, fire burned for 19 days, 15 Mcf consumed.	Not available.	18	Evans and Chadwick, 2009
El Segundo	Los Angeles	CA	Standard Oil Company of California	Early 1970s	Gas migration—threatening housing development.	Gas migration from reservoir to surface along fault lines. Facility finally shut in (pre-1993) but now abandoned for safety, due to new housing.	4, 5, 12, 13	Evans and Chadwick, 2009
Playa Del Rey	Los Angeles	CA	Southern California Gas Company	1/6/2013	The soot from the burned gas caused mist damage to neighboring homes, landscaping, and vehicles. Facility is currently shutdown during ongoing investigation and inspection of pipeline facilities.	At the Playa Del Rey underground storage facility, an unintentional and momentary opening of a block valve allowed a release of high-pressure gas into lower-rated pressure piping. This resulted in unplanned release of gas through the relieving valve system and an over-pressure of certain station piping. The gas emitted through the relief system ignited.	2, 4	PHMSA
Aliso Canyon	Los Angeles	CA	Southern California Gas Company	1/17/1994	Storage well damaged—crushed. Supply of gas from Aliso Canyon interrupted for five days.	Storage well damaged during 1994 Northridge Earthquake.	1, 17	Evans and Chadwick, 2009
Aliso Canyon	Los Angeles	CA	Southern California Gas Company	2008	High-pressure gas could migrate to the surface in a manner of hours, according to SoCalGas testimony.	Corrosion of storage well casing. Surface annulus of well Porter 50A had a pressure of over 400 psig.	1, 11	Evans and Chadwick, 2009
Aliso Canyon	Los Angeles	CA	Southern California Gas Company	2013	No evidence of the leaks at the surface or surface casing.	Two wells were found to have leaks in the production casing at depths adjacent to the shallower oil production sands.	1, 11	Evans and Chadwick, 2009
Aliso Canyon	Los Angeles	CA	Southern California Gas Company	2/4/2006	No injuries resulted from this incident. Overpressure was quickly alleviated, and relief valve reset.	A relief valve triggered on an underground storage facility wellhead, spraying petroleum mist on nearby brush and hillside. An investigation of this incident determined that while 400 barrels were being injected into the well, excessive backpressure during flowback occurred, tripping a relief valve, as designed, when pressure exceeded MAOP.	2	PHMSA
East Whittier	East Whittier	CA	Southern California Gas Company	1970s	Gas migrated from original injection site.	Injected gas produced by another company; facility finally closed in 2003.	4, 5, 12	Evans and Chadwick, 2009
Honor Rancho	Los Angeles	CA	Southern California Gas Company	1992	Storage well damaged—casing shoe leak.	Well inadvertently sidetracked during repair of casing shoe leak.	1, 11	Evans and Chadwick, 2009
Honor Rancho	Los Angeles	CA	Southern California Gas Company	1975–2008	Gas migration from Castaic reservoir to adjacent fields and then to surface.	Gas migrated laterally to shallower Honor Rancho and Tapia structures, via faults, and then to surface, killing oak trees—affected oil production in nearby producing wells.	1, 4, 12, 13, 14	Evans and Chadwick, 2009
Montebello	Los Angeles	CA	Southern California Gas Company	1950s–1980s	Storage gas lost over extended period. In 1980, found within housing estate above field—led to evacuation of families on many occasions.	Storage gas migrated via old, poorly completed wells and possibly faults. Injection pressure higher than original oilfield pressure, causing fracture and damage to old wells. Injection ceased 1980; facility closed 2003.	1, 5, 14	Evans and Chadwick, 2009
Playa Del Rey	Los Angeles	CA	Southern California Gas Company	4/1/2003	25 minute release of gas with a fine mist of oil.	Valve in compressor unit broke.	2	Evans and Chadwick, 2009
Playa Del Rey	Los Angeles	CA	Southern California Gas Company	1940s–2008	Migration of large amounts of stored gas.	Stored gas has migrated from PDR structure into Venice structure from earliest days, connection between structures, some fault and well-related.	1, 5, 12, 14	Evans and Chadwick, 2009
Wild Goose	Butte	CA	Wild Goose Storage Inc.	2/28/1999	Not specified.	Company had been operating the pipeline for 6 months at 1,400 psi. Because the operating pressure would be increasing in the near future, the decision was made to block in the wells allowing the pipeline pressure to increase to its maximum working pressure. When the pipeline reached a pressure of 1,580, a leak between two flanges was discovered.	2, 5	PHMSA

Folga et al. (2016) listed the main processes leading to UGS failure and the number of incidents worldwide that have occurred by each process in DHR facilities (non-purple entries) as shown in Table 1.2-9. As shown by comparing the numbers for processes (1) and (2), wells and surface infrastructure, respectively, the aboveground valves, pipes, wellheads, compressors, and other components have been associated with over four times (61) as many incidents as wells (14). Note further in Table 1.2-9 that some incidents involve more than one process, resulting in double-counting in the table. Table 1.2-9 shows that the majority of reported UGS incidents occur above ground (ID = 2), followed by design/construction failure (ID = 4), and well failure, including blowout (ID = 1).

It is apparent that Folga et al. (2016) come to a different conclusion about relative numbers of surface versus subsurface failures than Evans (2009). In particular, the results of Evans (2009) are contradicted by the more recent results in Folga et al. (2016), who note that far more surface-related incidents occur. Two important points are relevant: (1) the change in conclusion about importance of surface incidents arose because Folga et al. (2016) added the PHMSA data which are all surface-related, indicating that reporting, or what data one counts, controls the conclusion; (2) the consequences of surface incidents can be catastrophic (involving deaths) because the effects occur where there can be people present, but they can also be minor because surface failures are often promptly addressed by manual closing of valves or by automatic failsafe systems, or by some other emergency operational procedure.

Table 1.2-9. Contributory processes and worldwide number of DHR incidents attributed to those causes. Note that Folga et al. (2016) included salt cavern processes that are not applicable to California UGS (colored purple in the table to indicate lack of applicability in California).

ID	Main contributory processes attributed to leak/failure mechanism/abandonment of facility	Number of incidents in depleted hydrocarbon reservoir storage
1	well/casing/brine string/plug problems/failure, incl blowout	14
2	above ground infrastructure - valve/pipes/wellhead/compressor/gas detection system	61
3	loss of wellhead pressure or failed pressure test	0
4	design/construction failure - including site characterization, caprock performance, leaching	13
5	operational failure - overpressure/fill reservoir (spillpoint)/aquifer/cavern, operational procedures (human error)	11
6	operational failure - hydrostatic pressure too low, storage reservoir/cavern too shallow	0
7	Operational failure - low pressures, salt creep	0
8	operational failure - leaching (unknown & uncontrolled), cavern communication, roof collapse (salt or overburden)	0
9	caverns/void problems - fractures, creep, high insolubles, collapse/salt wall fall, filling with water (Russia)	0
10	inadvertent intrusion	5
11	during repair/testing/maintenance	6
12	migration from injection footprint/cavern (not due entirely to well problems)	10
13	cap rock - not gas tight/salt thick enough	2
14	cap rock - fractured/faulted, not gas tight	4
15	mine shaft	1
16	wet rockhead/sinkholes	0
17	seismic activity	2
18	not available	7

A great deal of information has been collected on the failure rates of pipelines and related infrastructure from a variety of industrial applications. For example, van Vliet et al. (2011) presented results of failure frequency for on-site aboveground, high pressure natural gas lines at onshore natural gas facilities. Aboveground natural gas lines have flanges that one might consider a greater hazard than straight piping. However, van Vliet et al. (2011) reported that a flange connection can withstand a larger impact and stress than the pipeline it is connected to. Therefore, van Vliet et al. (2011) excluded ruptures of flange connections from their risk calculations. Failure frequencies estimated by van Vliet et al. (2011) are shown in Table 1.2-10.

Table 1.2-10. Failure frequencies and time to event for 1 km pipeline for aboveground high-pressure gas lines (after van Vliet et al., 2011).

Failure category	Failure frequency (per m per yr)	Time to event for 1 km of pipe (yrs)
Rupture (> 1/3 pipe diameter)	6.5×10^{-9}	150,000
Large hole (1/3 diameter)	3.3×10^{-8}	30,000
Small hole (5 mm – 25 mm diameter)	6.7×10^{-8}	15,000
Pin hole (≤ 5 mm diameter)	1.6×10^{-7}	6,250

Vendrig et al. (2003) reported CO_2 pipeline failure rates and corresponding time to event likelihoods as shown in Table 1.2-11. As shown, the Modules 2-4 involving pipelines and compression have low failure rates and time to event estimates from 25 to nearly 3,000 years.

Table 1.2-11. Yearly failure rate summary per module from Vendrig et al. (2003).

Module		Expected failure rate (events per module per year)	Leak every x years
1	CO_2 recovery at source	1.5×10^{-1}	7
2	Converging pipelines	4.6×10^{-3}	217
3	Booster station	4.0×10^{-2}	25
4	10 km pipeline	3.4×10^{-4}	2,941
5	Injection well	1.8×10^{-1}	6

One can compare the estimates of Vendrig et al. (2003) for CO_2 pipelines with the estimates of van Vliet et al. (2011) for natural gas by assuming a 10 km pipeline and an intermediate frequency failure category (a large hole). From Table 1.2-10, we have $1/(3.3 \times 10^{-8}\ m^{-1}\ yr^{-1} \times 10{,}000\ m) = 3{,}030$ yrs as compared to Vendrig et al. (2003), who estimate time to event for 10 km CO_2 pipeline at 2,941 yrs. Because no one would expect a single pipeline to last 3,000 yrs, a more practical measure of the reliability of pipelines might be the translation of the above times to event into a measure such as the length of pipeline that one would need before expecting a failure in a decade. The 3,000 yr time to event estimated here would translate to the expectation of no failures in a decade over 3,000 km of pipeline (1 event/3,000 yrs/10 km = 1 event/10 yrs/3,000 km). Regardless of how it is quantified, it is clear that flowlines have very low failure frequency and long times to event.

As shown in Figure 1.0-1, UGS surface infrastructure comprises a lot more than flowlines, consisting also of compressors, gas processing equipment, turbine and reciprocating generators, valves, etc. And the statistics show that failures of surface infrastructure in general occur approximately four times more often than failures related to wells, as shown in Table 1.2-9. But there is a big difference in what can be done to mitigate and respond to surface infrastructure failure relative to (subsurface) well or reservoir integrity failure. The main difference is that surface ruptures of pipelines or other surface components are readily visible and apparent, so that operators can identify and locate leaks quickly and address

them by isolating the failed component(s) and closing valves, and then blowing down the affected system. Because leaks in surface infrastructure can be found and addressed quickly, the total amount of gas released tends to be small, resulting in small consequences. On the other hand, the presence of workers and potentially the public in the surface environment can also increase consequences in the event of fire or explosion associated with loss-of-containment. In contrast, loss-of-containment in the well environment, e.g., through a casing breach at depth, is difficult to detect and repair, and total LOC amounts can be large with no impact to people. When such leakage goes on undetected, the problem can grow and become worse until one has a blowout which can sometimes be difficult to kill, as demonstrated by the 2015 Aliso Canyon incident. This points to the need for effective monitoring.

1.2.4.1.3 Estimates of Likelihood Based on Recorded LOC Incidents

Based on the compilation of Folga et al. (2016), we can estimate the likelihood of LOC failures in California a few different ways. We show in Table 1.2-12 the 12 current California UGS facilities ranked by working-gas capacity and showing years of operation and number of reported LOC incidents extracted from Folga et al. (2016). From this information, we can estimate likelihood of LOC incidents in terms of incidents per year, time to incident, and probability of incident.

Before presenting any results from this analysis, several caveats are needed. First, there are only 12 incidents in Table 1.2-12, and five of the UGS facilities have no recorded incidents at all, making calculation of time to event questionable for those facilities. Nevertheless, failure frequencies are needed to evaluate risk, and these data (and more recent additions; see below) are all that we have in the public domain to use. Second, we note that failure rates may not be constant with time and in fact may increase as facilities age. Therefore, the estimated failure frequencies below may be lower than expected in the future. Finally, note also that only seven of the 12 UGS facilities have reported LOC incidents in the data presented by Folga et al. (2016) that are used here and yet, consistent with the practice of Evans (2008) and Folga et al. (2016), average rates of failure are calculated over all facilities.

The first-order conclusion from this exercise is that the overall likelihood of LOC incidents is 12 incidents/434 facility-yrs = 0.028 incidents/facility-yr or 0.33 incidents/yr at any of the 12 facilities statewide. This corresponds to a time to event of 36 yrs for any given facility on average, and 3.0 yrs (36/12) for all facilities statewide. This can be compared with the frequency estimated by summing the individual likelihoods for all 12 facilities, which comes to 0.278 incidents/yr (or 0.023 incidents/facility-yr), which corresponds to a statewide time to event of 3.6 yrs. The reason the likelihoods of statewide LOC incidents differ (0.33 incidents/yr vs. 0.278 incidents/yr) for these two calculation approaches is that different facilities operated for different periods of time, and this is not accounted for in the former approach.

Second-order conclusions can be drawn for the individual facilities. For example, the time to event for LOC incidents at Aliso Canyon is 14 yrs, whereas the time to event for

Honor Rancho LOC incidents is 41 yrs, and other facilities with reported LOC incidents fall somewhere in between. Aliso Canyon, McDonald Island, and Playa del Rey have more reported LOC incidents (2-3) than any of the other sites. It is important to note that Aliso Canyon and McDonald Island store the most gas of all of the sites. Using a Bcf-weighted likelihood measure (last column in the table in Table 1.2-12), we see that the per Bcf-yr likelihoods of LOC incidents are the lowest for McDonald Island and Aliso Canyon because they have large working gas capacities (store a lot of gas). Playa del Rey has the highest likelihood of LOC incidents using the Bcf-weighted approach because it has three reported incidents and only stores 2.4 Bcf, the second smallest UGS capacity in California. Breaking down the likelihoods for depleted oil reservoirs and depleted gas reservoirs shows approximately equal average likelihoods for LOC failure in oil reservoirs (0.13 LOC incidents/yr) versus average likelihood for LOC failure in gas reservoirs (0.15 LOC incidents/yr).

Table 1.2-12. California UGS facilities (coded red if LOC incident has been recorded, green if not) ranked by capacity showing number of LOC incidents and four different measures of likelihood: (1) LOC incidents/yr, (2) time to event (yrs), (3) likelihood per yr, and (4) incidents per capacity-weighted yr in units of per Bcf-yr).

Field name	working gas capacity (Bcf)	depleted oil (O) or depleted gas (G)	year established	years of operation (until 2016 to match Folga et al.)	capacity-weighted years of opn (Bcf-yrs)	number of distinct LOC incidents from Evans (2009) and Folga et al. (2016)	LOC incidents/year of operation	time to event, t (yrs)	Likelihood, P = 1/(1+ t) per year	incidents /capacity-weighted years (per bcf-yr)
Aliso Canyon	86.0	O	1973	43	3698	3	6.98E-02	1.4E+01	6.5E-02	8.11E-04
McDonald Island	82.0	G	1976	40	3280	2	5.00E-02	2.0E+01	4.8E-02	6.10E-04
Wild Goose	75.0	G	1997	19	1425	1	5.26E-02	1.9E+01	5.0E-02	7.02E-04
Lodi	29.5	G	2001	15	443	0	0.00E+00	1.0E+06	1.0E-06	0.00E+00
Honor Rancho	24.2	O	1975	41	992	1	2.44E-02	4.1E+01	2.4E-02	1.01E-03
Gill Ranch	20.0	G	2010	6	120	0	0.00E+00	1.0E+06	1.0E-06	0.00E+00
La Goleta	19.7	G	1941	75	1478	0	0.00E+00	1.0E+06	1.0E-06	0.00E+00
Los Medanos	18.0	G	1979	37	666	1	2.70E-02	3.7E+01	2.6E-02	1.50E-03
Kirby Hills	15.0	G	1975	41	615	0	0.00E+00	1.0E+06	1.0E-06	0.00E+00
Princeton	11.0	G	2010	6	66	0	0.00E+00	1.0E+06	1.0E-06	0.00E+00
Playa del Rey	2.4	O	1942	74	178	3	4.05E-02	2.5E+01	3.9E-02	1.69E-02
Pleasant Creek	2.3	G	1979	37	85	1	2.70E-02	3.7E+01	2.6E-02	1.18E-02
Totals:	385.1			434	13045	12	2.91E-01		0.278	

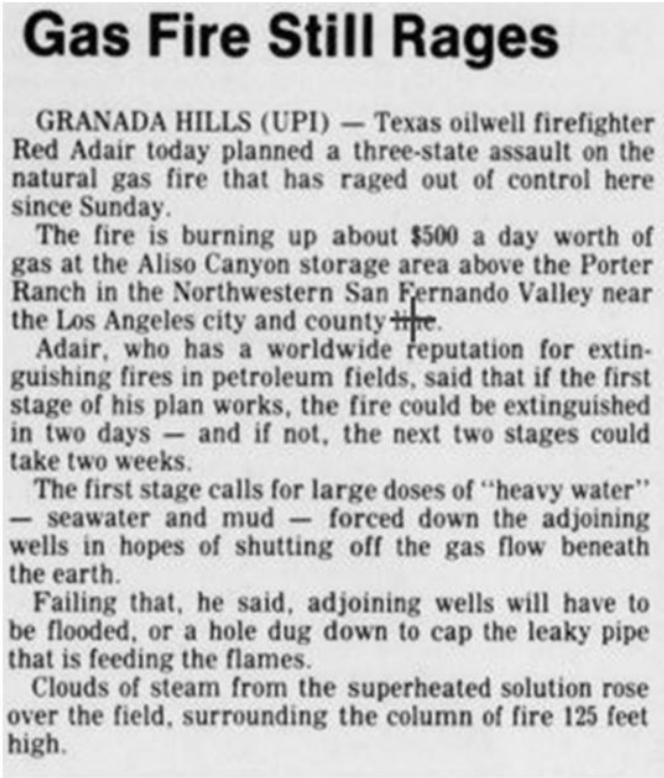
Note that we chose to base the above analysis entirely on the data of Evans (2009) and Folga et al. (2016), and that we did not include Montebello in the analysis. There are three significant points to mention related to these choices, two of which we will address below to improve the incident likelihood estimate.

First, we did not include Montebello in Table 1.2-12 despite the fact that its official cessation of operations was December 31, 2016, placing it within the time period of this study.

The reason we neglected it is that its operational history since 1997 is questionable (see Appendix 2-4 in Chapter 2) making it difficult to obtain information on it for the study period. In addition, it is not possible to determine a time frame for incident occurrence because Montebello has a long history of leakage that is not divided into distinct incidents in the database but rather lumped as a single entry. Nevertheless, the fact is that natural gas from the Montebello UGS facility leaked through abandoned wells into homes as described in Tables 1.2-7 and 1.2-8, leading to evacuations in the early 1980s and tearing down of homes to re-abandon wells properly (Chilingar and Endres, 2005). In short, while we cannot easily include incidents at Montebello in the simple analysis here, we point out that the Montebello UGS facility sustained serious LOC incidents due to well integrity failure, and these occurrences should be informally factored into the estimates of likelihood of LOC incidents due to well integrity failure.

Second, neither Evans (2009) nor Folga et al. (2016) included the 1975 Aliso Canyon incident, which consisted of an ignited gas blowout caused by sand production and failure of an elbow at the wellhead due to erosion by the sand (Hauser and Guerard, 1993). This incident is described in the newspaper article reproduced in Figure 1.2-26. We have not found additional information or details about this incident, but we have added it in to the number of LOC incidents involving well integrity failure in our updated calculation of incident likelihood that immediately follows.

Third, the 2015 Aliso Canyon incident was not in Evans (2009) (pre-dated the incident) nor in Folga et al. (2016) (relied on Evans, 2009). We have also included this incident in the updated incident likelihood estimate that immediately follows.



Gas Fire Still Rages

GRANADA HILLS (UPI) — Texas oilwell firefighter Red Adair today planned a three-state assault on the natural gas fire that has raged out of control here since Sunday.

The fire is burning up about $500 a day worth of gas at the Aliso Canyon storage area above the Porter Ranch in the Northwestern San Fernando Valley near the Los Angeles city and county line.

Adair, who has a worldwide reputation for extinguishing fires in petroleum fields, said that if the first stage of his plan works, the fire could be extinguished in two days — and if not, the next two stages could take two weeks.

The first stage calls for large doses of "heavy water" — seawater and mud — forced down the adjoining wells in hopes of shutting off the gas flow beneath the earth.

Failing that, he said, adjoining wells will have to be flooded, or a hole dug down to cap the leaky pipe that is feeding the flames.

Clouds of steam from the superheated solution rose over the field, surrounding the column of fire 125 feet high.

Figure 1.2-26. Desert Sun newspaper article from January 21, 1975 describing the 1975 Aliso Canyon incident.

If we add in the 1975 and 2015 Aliso Canyon incidents to the numbers in Table 1.2-12, we would have 14 total LOC incidents, making the frequency 14 incidents/434 facility-yr = 0.032 incidents/facility-yr or 0.39 incidents/yr for the 12 facilities statewide. The corresponding updated time to event is 2.6 yrs compared to the prior estimate of 3 yrs. For Aliso Canyon alone, the incident frequency is 5 incidents/43 yr = 0.116 incidents/yr, or a time to incident of 8.6 yrs. The depleted oil reservoir UGS LOC incident likelihood when we include the 1975 and 2015 Aliso Canyon incidents is equal to 0.17 LOC incidents/yr versus 0.13 LOC incidents/yr without these additional two incidents.

1.2.4.2 Comparison with Prior Estimates of Likelihood for Worldwide UGS

Folga et al. (2016) calculated the overall likelihood of UGS incidents as between 8.4×10^{-4} and 6.0×10^{-3} per facility yr (see Table 4.2-5 in Folga et al. (2016)). The estimates of Folga et al. (2016) include salt cavern, aquifer, and DHR storage types and are calculated based on total worldwide reported incidents, not just for California and not just for LOC. In addition, the Folga et al. (2016) table (Folga et al. (2016), Table 4.2-5) shows that salt cavern incident likelihoods are higher than for DHR. As such, the Folga et al. (2016) estimates are

conservative (i.e., they err on the high side) relative to DHR LOC incidents. Despite the expected higher values of Folga et al. (2016) relative to actual, the California-only DHR LOC incident likelihood as summarized in Figure 1.2-13 is 3.5 times higher at 0.021 incidents per facility-yr compared to the Folga et al. (2016) upper value of 6.0×10^{-3} incidents per facility-yr. The original Evans (2009) and the recent update by Evans and Schultz (2017) also report much higher likelihood of LOC incidents for California UGS facilities relative to the rest of the world.

Whether or not the failure rate for California UGS facilities is actually higher than the rest of the U.S. and world is an open question. The reason one cannot conclude that California LOC incidents are higher than the rest of the world is that the statistics depend on the reporting that has populated the databases. It is possible that California has reported incidents more completely than is typical, resulting in more incidents in the database. Another possibility is that California's larger individual facilities may store and handle a lot more gas than other facilities in other regions, resulting in more vulnerability to LOC incidents. The U.S. stores approximately 1/3 of all gas stored worldwide (IEAGHG, 2006), and California stores (and handles) a significant amount of gas (~385 Bcf working gas capacity).

1.2.5 Recent Updates to the Incident Database

1.2.5.1 Global Update

During the course of this study, the Evans (2009) database was updated by Evans and Schultz (2017) and is still undergoing quality control and validation at the time of writing this section (Evans, pers commun.). Nevertheless, Evans and Schultz have generously shared some preliminary results of querying their updated database for use in this report. The main improvements that Evans and Schultz (2017) have made in the database were to (1) add to the database those incidents that Evans and Schultz have found reported in publicly available documents since 2008; (2) add to the database older incidents that were not included in the 2008 database because they were not known at the time (typically not then electronically searchable, but now electronically searchable), and (3) add in the reported or estimated severity of the incident, which adopted a 1-8 scale in an attempt to undo some of the range compression noted in scales limited to 1-5 and which are commonly used in risk-management approaches such as risk matrices.

In total, the updated Evans and Schultz (2017) database contains 1,023 recorded incidents (up from 228 incidents in the 2008 database) from around the world involving underground fuel storage in all of its forms (aquifer, depleted hydrocarbon reservoir, salt cavern, mined opening). The database contains 528 incidents recorded for natural gas (methane) in DHR storage facilities. Of these, 166 involved subsurface well integrity, 69 involved subsurface storage integrity, six were due to direct human error, 286 involved aboveground infrastructure, and one was unknown. Globally, 235 incidents were subsurface-related and 282 were surface-related, and seven were unspecified. From these data, we conclude that globally surface incidents slightly exceed subsurface incidents

(286/235 = 1.2). Ignition and/or explosion occurred in 64 of the incidents, with six fatalities, 23 injuries, and 11,372 evacuees. To see how these kinds of consequences map to severity, we present in Table 1.2-13 the eight degrees of severity defined by Evans and Schultz (2017). While we do not endorse every detail of the Evans and Schultz (2017) severity descriptions, we support the idea of ranking incidents by severity, and use their table for illustrative purposes in the discussion below.

Table 1.2-13. Evans and Schultz (2017) severity categories.

Severity	Category	Description
1	*Insignificant/nuisance*	operational issues that were easily rectified or repaired, not involving leakage of product fire/explosion/blowout, injury, evacuees, fatalities or leading to financial losses
2	*Minor/ disruptive*	issues including minor/small leakages/surface release, cavern instabilities that were rectified or repaired, vapour flash, but no real financial loss, fire/explosion/blowout, injury, evacuees or fatalities
3	*Moderate (1)*	issues including substantial losses through subsurface leakages, but not involving surface release, leading to financial losses, but no fire/explosion/blowout, injury, evacuees or fatalities
4	*Moderate (2)*	issues including substantial operating problems (including shut-down, closure of caverns &/or loss of roof salt) or substantial losses through subsurface leakages, involving surface release, gas in observation or water wells, or pipeline leakages, leading to financial losses, ± fire/explosion/blowout, but no injury, evacuees or fatalities
5	*Significant*	issues including significant leakages/losses and surface release, fire/explosion/blowout leading to financial losses, minor numbers of injured/injuries (1–5), but no evacuees, fatalities or serious property damage
6	*Serious*	issues mainly involving significant surface release, fire/explosion/blowout, greater number of injured/serious injury (5–10), evacuees (<50) and/or serious property damage/financial losses but no fatalities
7	*Major*	issues mainly involving large-scale surface release through well or surface pipelines, ± fire/ explosion/blowout, high numbers of evacuees (50–500), large number of injured/serious injury (10–15) and/or significant property damage/financial losses, but no fatalities
8	*Catastrophic*	issues mainly involving devastating surface release at facility through well or surface pipelines, fire/explosion/blowout, cratering, fatalities, high number of injured (>15) and/or evacuees (>500) and major property damage/financial losses

A large number of new incidents (229) relative to the Evans (2009) database were added to the PHMSA database (and that of Evans and Schultz database) as a result of the CPUC directive of January 26, 2016 to UGS operators in California to inspect their facilities for leaks. The results of this directive are shown in Table 1.2-14 as compiled by Evans and Schultz (2017). The vast majority of the incidents reported are classified as minor nonhazardous and easily remediated. We note the classifications in Table 1.2-14 are not those of Evans and Schultz (2017) as shown in Table 1.2-13, but rather those of theCPUC, who uses the following definitions for severity indicated by Grade 1 – 3:

> *A "Grade 1 leak" is a leak that represents an existing or probable hazard to persons or property and requiring prompt action, immediate repair, or continuous action until the conditions are no longer hazardous.*
>
> *A "Grade 2 leak" is a leak that is recognized as being not hazardous at the time of detection but justifies scheduled repair based on the potential for creating a future hazard.*
>
> *A "Grade 3 leak" is a leak that is not hazardous at the time of detection and can reasonably be expected to remain not hazardous.*

(Source: docs.cpuc.ca.gov/PublishedDocs/Published/G000/M163/K327/163327660.docx accessed 7/18/17). As such, the severity of the 229 incidents as described in column 5 (SED Classification) of Table 1.2-14 would all fall into the Severity 1-2 range, except for the Wild Goose (surface) and McDonald Island (surface and subsurface) LOC events, which may be Severity 3-4 by the new Evans and Schultz (2017) scale.

Table 1.2-14. Summary of results of the CPUC directive for leak detection in California (from Evans and Schultz, 2017).

Facility	Operator	Leaks Found	Leaks Repaired	SED Classification	Location of Leak	Remedial Actions
Aliso Canyon	SoCalGas	66	66	Minor non-hazardous	Above ground	Tightening, adjustment, lubrication or replacement of parts or piping.
La Goleta	SoCalGas	17	17	Minor non-hazardous	Above ground	Tightening, adjustment, lubrication or replacement of parts or piping.
Honor Rancho	SoCalGas	1	1	Non minor non-hazardous	Above ground	Tightening, adjustment, lubrication or replacement of parts or piping.
		13	13	Minor non-hazardous	Above ground	Tightening, adjustment, lubrication or replacement of parts or piping.
Playa Del Rey	SoCalGas	3	3	Minor non-hazardous	Above ground	Tightening, adjustment, lubrication or replacement of parts or piping.
Montebello	SoCalGas	6	6	Minor non-hazardous	Above ground	Tightening, adjustment, lubrication or replacement of parts or piping.
Wild Goose Storage	Wild Goose Storage Inc.	27	21	3 (High priority) 8 (Medium priority) 16 (Low priority)	All above ground	21 leaks repaired and corrective actions begun to address remaining six leaks but final repair had not been completed by March 2016.
Lodi	Lodi Gas Storage LLC	0	0	Not applicable	Not applicable	Not applicable
Central Valley Gas Storage	Central Valley Gas Storage LLC	2	2	Grade 3	Above ground	Repaired on 2/4/16 and 2/5/16
Gill Ranch Storage	Gill Ranch Storage LLC	10	1	1 (Grade 2) 9 (Grade 3)	Above ground	Grade 2 leak was repaired 2/9/16. Grade 3 leaks were scheduled to be repaired within 60 days.
Los Medanos	PG&E	23	23	8 (Grade 1) 18 (Grade 2) 58 (Grade 3)	Above ground	Seven leaks were awaiting remedial action. PG&E completed remediation of 17 leaks of the 24 leaks as of 3/6/2016. The remaining 2 Grade 1 leaks had blown down and were not leaking at time of report, but required assistance from third party vendor to complete the repair.
Pleasant Creek	PG&E	29	29		Above ground	
McDonald Island	PG&E	32	25		23 (Above ground)	
					1 (Below ground)	
Totals		229				

1.2.5.2 Update to California Incidents

To update our analysis of the frequency and location of occurrence (surface or subsurface) of California UGS incidents that were based on the Evans (2009) and Folga et al. (2016) databases as presented above, we requested that Dr. Evans query the database to (1) count all of the California UGS incidents in the new database that occurred up until December 31, 2015, and (2) count all of the incidents occurring between January 1, 2006, and December 31, 2015, the nominal time period for UGS analysis in this report. These do not therefore

contain those reported incidents arising from the CPUC directive of January 26, 2016. As shown in Table 1.2-15, a total of 105 incidents are in the database for California, of which 46 are Severity Level 4 ("Moderate(2)") and 42 are Severity Level 2 ("minor, disruptive"). Within our study period from January 1, 2006, until December 31, 2015, Table 1.2-16 shows that the database query for incidents at California UGS facilities nets 63 incidents, of which 39 are Severity Level 4, and 20 are severity Level 2. Note that incidents involving well integrity are by far the most common problems reported, and surface incidents are far outnumbered by subsurface incidents (5/57 = 0.09) in the study period. This contrasts with the global incidence surface to subsurface ratio of (286/235 = 1.2) discussed above, which implies either that California well and caprock/subsurface integrity failures are much more common than globally (many more subsurface incidents) or that California surface infrastructure is much less prone to incidents, which seems very unlikely. The single Severity Level 8 result for both queries is the Aliso Canyon SS-25 well blowout incident. These data shown in Tables 1.2-11 and 1.2-12 are plotted in the pie charts of Figures 1.2-26 and 1.2-27. We note that there are 57 total Severity 4 or higher incidents over all time (Table 1.2-15) and 41 total Severity 4 or higher incidents during the study period (Table 1.2-16).

Table 1.2-15. Evans and Schultz (2017) database hits for California incidents in UGS up to December 31, 2015.

		Severity								
Number	**Mechanism**	***1***	***2***	***3***	***4***	***5***	***6***	***7***	***8***	***Total***
84	***Well Integrity***	0	36	1	42	0	1	3	1	84
1	***Operations/Human error***	0	0	0	1	0	0	0	0	1
5	***Caprock/Subsurface Integrity***	0	0	3	2	0	0	0	0	5
15	***Above ground infrastructure***	2	6	0	1	5	1	0	0	15
0	***Above ground infrastructure/operational***	0	0	0	0	0	0	0	0	0
105	***All***	2	42	4	46	5	2	3	1	105

Table 1.2-16. Evans and Schultz (2017) database hits for California incidents in UGS for the period January 1, 2006 up to December 31, 2015.

		Severity								
Number	**Mechanism**	***1***	***2***	***3***	***4***	***5***	***6***	***7***	***8***	***Total***
57	***Well Integrity***	0	17	1	38	0	0	0	1	57
1	***Operations/Human error***	0	0	0	1	0	0	0	0	1
0	***Caprock/Subsurface Integrity***	0	0	0	0	0	0	0	0	0
5	***Above ground infrastructure***	1	3	0	0	1	0	0	0	5
0	***Above ground infrastructure/operational***	0	0	0	0	0	0	0	0	0
63	***All***	1	20	1	39	1	0	0	1	63

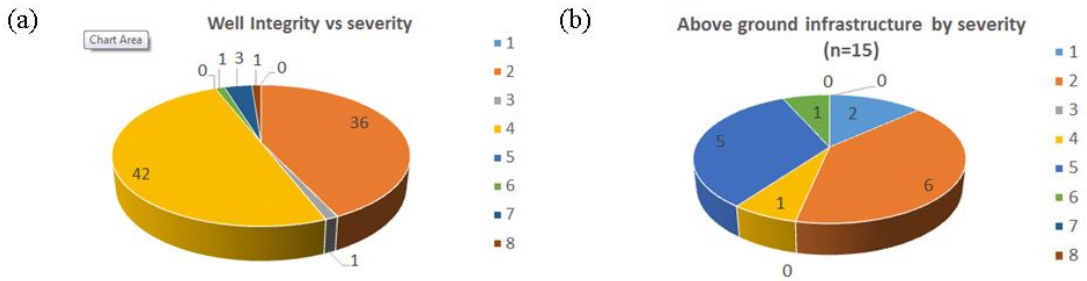


Figure 1.2-27. Counts of UGS incidents by severity up until December 31, 2015 in the updated database of Evans and Schultz (2017).

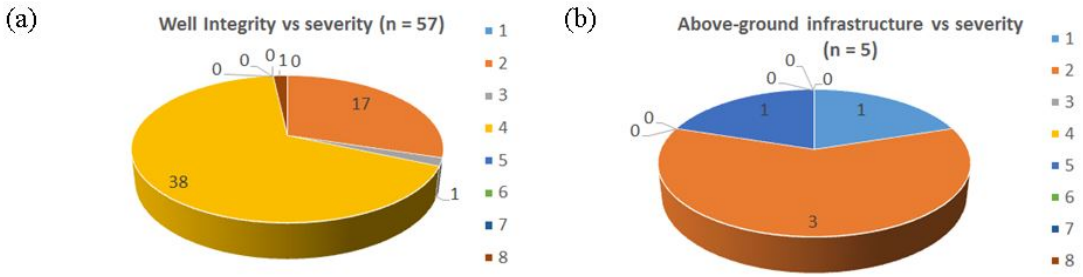


Figure 1.2-28. Counts of UGS incidents by severity for the study period January 1, 2006 until December 31, 2015 in the updated database of Evans and Schultz (2017).

If we consider a threshold of Severity Level 4, which would include incidents that disrupted operation and therefore disrupted reliability of the facility, we count 57 incidents overall and 41 incidents in the project study period. The 57 overall count of California incidents is more than five times the previous count (11) based on the Evans (2009) and Folga et al. (2016) databases (see Table 1.2-8). The quintupling of incidents since 2008 is not likely representative of an increase in frequency of incidents, but rather is more likely an artifact of reporting. For example, the additional 229 California incidents reported in 2016 under the CPUC directive include approximately 10 incidents from the McDonald Island and Wild Goose facilities (Table 1.2-14). Based on the current reporting as recorded in the Evans and Schultz (2017) database as shown in Figure 1.2-28, we estimate the frequency of significant failures (Severity 4 or larger) during the study period by dividing the 41 reported significant incidents by 120 facility years to obtain 0.342 incidents/facility-yr. If there are 12 facilities, we can expect, based on these data, 4.1 incidents every year from some facility somewhere in California. And we can expect that the most likely incidents will be related to well integrity. We note that Severity 4 LOC incidents involve no injuries, evacuees, or fatalities.

1.2.6 Human and Organizational Factors

Humans are widely cited as an important cause of UGS incidents by Evans (2009) and Schultz et al. (2017), whereas human factors as a cause of incidents are not emphasized by Folga et al. (2016). Evans and Schultz (2017) note that operational errors and human errors are often difficult to differentiate, as many operational occurrences result from some sort of human error.

The recognition and analysis of human and organizational factors (HOFs) in risk analysis in the oil and gas industry is growing. Reviews and analysis examples are available in the literature. For example, Tabibzadeh and Meshkati (2014) use the 2010 Gulf of Mexico Macondo well as motivation for the need for consideration of HOFs in deep off-shore oil and gas operations, and present a framework for doing so. In a subsequent paper addressing the Aliso Canyon SS-25 well, Tabibzadeh et al. (in press) utilize Rasmussen's AcciMap organizational principle (Rasmussen, 1997) to describe graphically a hierarchy of contributing factors at Aliso Canyon that led to the SS-25 blowout. HOFs are very significant causes of UGS incidents, and we discuss the need for increased training of UGS staff and emphasis on training for off-normal incidents as a way of addressing HOF in Section 1.6.

In addition to the acts of omission or commission that responsible management, operators, engineers, field technicians, and subcontractors in various areas of a UGS facility may carry out inadvertently, there can also be nefarious human factors. In particular, the threats of terrorism, vandalism, violence, or property destruction by internal or external individuals or groups cannot be ignored. Bajpai and Gupta (2007) provide an excellent summary of this threat and its mitigation for oil and gas infrastructure, an analysis appropriate also for UGS in California. Given the proliferation in terrorism and active shooter incidents over the last 20 years, UGS facilities should continuously evaluate security and minimize the attractiveness of their facilities to individuals and groups intent on harming the facility, its workers, or the general public.

1.2.7 LOC Emission Rates and Dispersion Patterns

The accidental release of high-pressure natural gas at UGS facilities can pose a significant threat to people and property in the vicinity of the leak (see Section 1.4.7). Emission rates can be very large from ruptures in high-pressure pipes, wellheads, compressors, and tanks. For example, during the 2015 Aliso Canyon incident, the SS-25 well emitted natural gas at a rate starting at about 57 tonnes/hr (16 kg/s) in October 2015, and only declined to about 20 tonnes/hr (5.5 kg/s) over the nearly four months until the time the blowout was stopped by means of a relief-well kill (Conley et al., 2016). Flowline ruptures can also produce large flow rates before leaking sections are isolated and the leak is stopped. Blowouts and ruptured lines are typically acute incidents with clear start and end times. At the other end of the spectrum of LOC incidents are chronic and very low-flow-rate leaks from seals and valves that do not create health or safety hazards but that may be significant from a greenhouse gas (GHG) emission standpoint (see Section 1.5). It is often hard to document when these chronic incidents begin because they are hard to detect. For the same reasons, slow chronic leaks may persist for long periods because they are not detected and/or do not create a high-priority safety-related condition.

Regardless of leakage rate, leaking natural gas will disperse following discharge into the atmosphere by the turbulence and air entrainment related to the high-pressure discharge, by local wind and atmospheric instability, and by buoyancy, which can be either positive (leaked gas tends to rise) or negative (leaked gas tends to fall) due to compositional and temperature (expansion cooling) effects on the leaking gas density relative to local air. If ignition occurs, the local wind field can change drastically, and different kinds of flaming and dispersion effects can occur (see next section). The hazards associated with ignition of leaking gas and human exposure (see Section 1.4) to leaking natural gas are controlled by the concentration of the gas at the locations of the people and therefore controlled by gas dispersion.

Leak rates and meteorological data can be combined to model downwind dispersion and estimate concentrations as a function of space and time. We present here an application of this method for demonstration purposes and to estimate the nature of dispersion around California UGS sites in a general sense. The approach we use is based on meteorological data collected from stations that are part of NOAA's Integrated Surface Database (ISD) and located closest to the various underground storage facilities as shown in Appendix 1.B. Using the meteorological data, UGS locations, and an atmospheric dispersion model, we can estimate the extent of flammable natural gas leaking from the UGS facilities for given leakage flow rates. We emphasize that these estimates are approximate because the meteorological data are extrapolated over long distances from the measurement sites to the UGS facilities. Furthermore, although the model is transient, it provides time-averaged values relative to what in reality are rapidly fluctuating concentrations.

The model that we use is NOAA's High-Resolution Rapid Refresh (HRRR) model with real-time 3 km resolution, hourly updated, cloud-resolving, convection-allowing atmospheric dispersion initialized on 3 km grids with 3 km radar assimilation. Radar data are assimilated

in the HRRR every 15 min over a 1 hr period adding further detail to that provided by the hourly data assimilation from the 13 km radar-enhanced Rapid Refresh. The model uses the community-based Advanced Research version of the Weather Research and Forecasting (WRF) Model known as the Advanced Research WRF (ARW) and Gridpoint Statistical Interpolation (GSI) analysis system. Modifications have been made to the community ARW model (especially in model physics) and GSI assimilation systems, some based on previous model and assimilation design innovations developed initially with the Rapid Update Cycle (RUC) (https://www.ncdc.noaa.gov/isd, accessed July 26, 2017). Model data for the period 08/15/2015 – 08/15/2016 were archived at National Institute of Standards and Technology (NIST) from the NCEP operational runs (http://nomads.ncep.noaa.gov/). Wind speed and direction at 10 m above ground along with the shortwave incoming radiation and cloud cover were extracted at each storage facility. Additional details on dispersion modeling are provided in Appendix 1.B.

Annual averaged values of dispersion data were computed for each storage facility for four different times of the day; 00-06 (night), 06-12 (morning), 12-18 (afternoon), 18-24 (evening) PST. The averaged wind speed and wind direction data were subsequently combined with plume dispersion models to compute the concentrations downwind of the storage facility. Furthermore, we use a unit flow rate (1 kg/s) as point source(s) from well(s) for the dispersion calculation and then normalize the resulting concentration field by the actual overall facility leak rate. If the leak rates are very large, then downwind concentrations may also be large, even though the concentrations decay with distance from the leak in an exponential manner. When the leak rates are small, the downwind concentrations close to the leak site will be relatively small.

In Figure 1.2-29, we show the average downwind concentration per unit flow rate for the Aliso Canyon facility as an example. The model assumes that each well is a point source that emits an amount of methane equal to the maximum flow rate from the 2015 Aliso Canyon incident (16 kg/s = 57 t/hr) divided by the number of wells present. The top-left panel in Figure 1.2-29 shows the concentration (C) per leakage flow rate (Q) superimposed on a GoogleEarth image of the storage facility, with the boundaries of the facility marked in black. C has dimensions of mass per volume (e.g., kg m^{-3}) while Q has dimensions of mass per time (e.g., kg s^{-1}), making C/Q have dimensions of time per volume (e.g., s m^{-3}). The white contours indicate the contour levels for C/Q scaled by a factor 10^9. The complete set of downwind concentrations for all UGS sites in California is shown in Appendix 1.B. The calculated downwind C/Q ratios are particularly useful because the contour levels can be multiplied by the actual leak rate to obtain the average concentrations downwind of the UGS facility.

For example, the modeled Aliso Canyon C/Q field is shown in Figure 1.2-29 assuming that all 115 wells at Aliso Canyon each emitted 16/115 kg/s for a total emission equal to the peak of the 2015 Aliso Canyon incident. If we consider the white C/Q contour labeled 42

(42×10^{-9}) m^{-3} s, and multiply this value by the total facility leakage rate of 16 kg s^{-1}, we obtain 16 kg $s^{-1} \times 42 \times 10^{-9}$ m^{-3} s = 6.7×10^{-7} kg m^{-3} = 670 mg m^{-3}. In short, the contour labeled 42 in Figure 1.2-29 corresponds to a CH_4 concentration of 670 mg m^{-3}, which is approximately 1 ppmv, which would correspond to an elevation of 1 ppmv above the background, which is approximately 4 ppmv in the area of Porter Ranch (see Section 1.4.10.2). It is important to note that concentrations much higher than this calculated value ($\sim 10^3$ times higher) were observed in the Porter Ranch neighborhood (see Section 1.4.10.3). The reason for this discrepancy between model and reality is that the model is time-averaged and does not account for local anomalous winds, for example canyon breezes that can advect leaking CH_4 directly down into the neighborhood. Furthermore, the SS-25 well was a point source, whereas this model assumes the equivalent leakage rate was spread out among 115 wells.

What good are these models if they cannot match observations? The fact is that these models can be very accurate if they are provided with accurate wind and flow-rate data. We have presented results here in the spirit of showing what is possible, and not to predict actual concentrations that can be used today for hazard assessment.

To summarize, acute LOC from high-pressure gas systems at UGS facilities can lead to very high flow rates, producing potentially catastrophic impacts near the leak source. And UGS facilities can also suffer from chronic low-level leakage that persists over time. Throughout the spectrum of leakage rates and durations, natural gas will disperse above ground as it flows away from the leakage source area. The patterns and degree of dispersion can be simulated for hazard assessment, risk assessment, emergency response planning, and land-use and facility planning purposes, provided the models use accurate local wind and leakage flow-rate data.

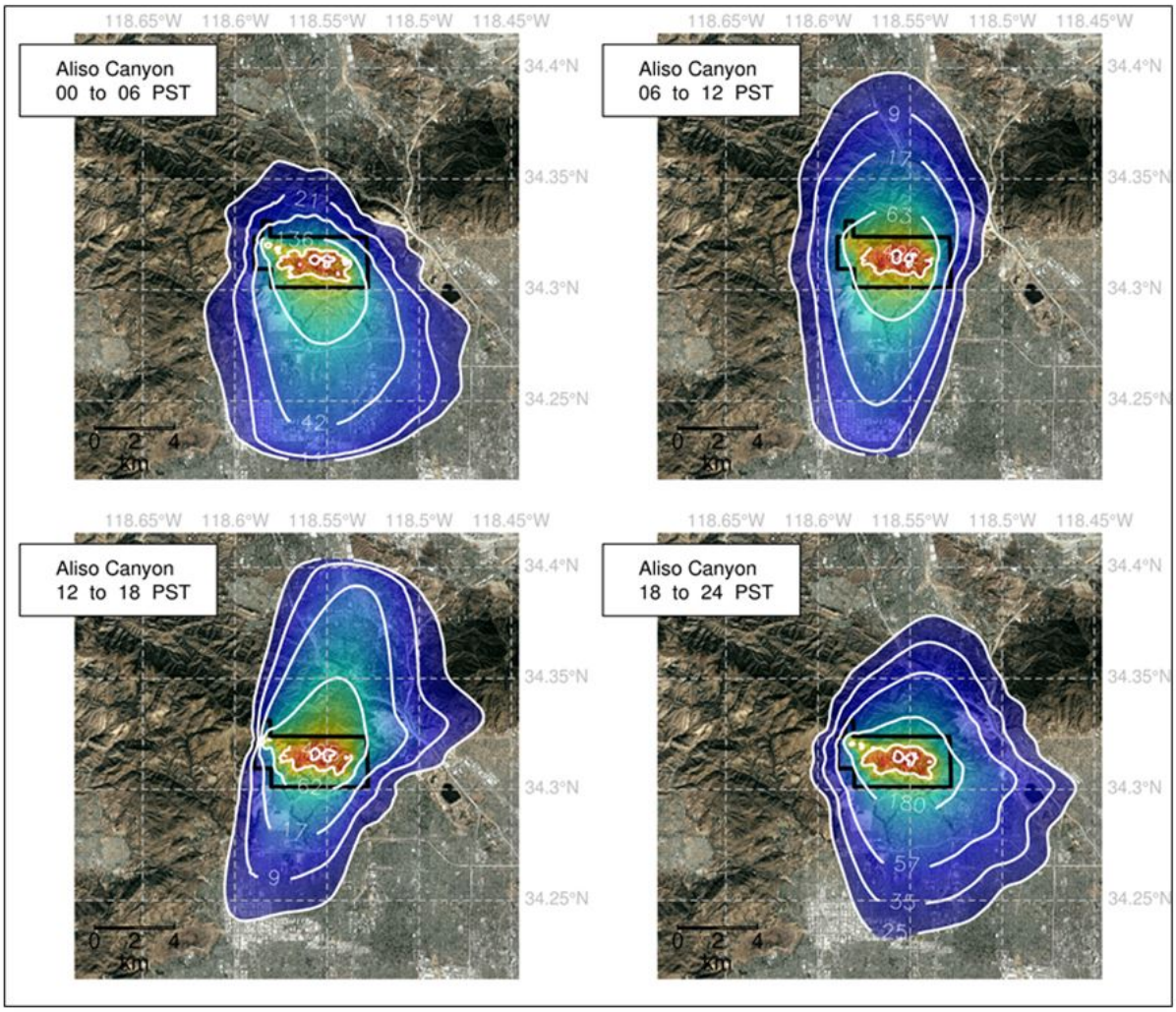


Figure 1.2-29. Simulated contours of atmospheric dispersion of leaking natural gas shown by contours of concentration divided by unit flow rate (C/Q) for four different periods during the day. The contour values are multiplied by 10^9. These are general results to demonstrate the modeling approach and the concentration values predicted here should not be used for hazard assessment.

1.2.8 Potential Impacts of LOC on UGS Infrastructure

Potential impacts of LOC on health and safety, including hazards of chemicals that could be released with leaking gas, e.g., mercaptan odorants, are discussed in Section 1.4. In this section, we discuss potential impacts to infrastructure. The dominant hazards from the release of high-pressure natural gas at UGS facilities include thermal radiation from sustained fire and collapse of buildings from explosions inside of buildings or in partially confined areas, e.g., areas partially enclosed by buildings. Decompression cooling as natural

gas expands to atmospheric pressure can cause small leaks to turn into large leaks as pipeline or tank-wall steel becomes brittle and fractures during leakage, thereby creating a larger opening. Small LOC incidents, if ignited, can trigger much larger incidents as flames damage other infrastructure. The source of flowing gas can be from the ground (e.g., during a breach blowout), from around wells (e.g., well cellars), from the wellheads, flowlines, flanges, or any other surface components of the UGS system (e.g., Figure 1.0-1). As observed in the 2015 Aliso Canyon incident, unignited releases result in much smaller consequences for infrastructure. Because we are focused on impacts of LOC to infrastructure here, we assume that ignition sources exist and that ignition will occur provided the flammable gas is within its flammability concentration range.

The same methods used in the previous section to simulate dispersion of leaking natural gas can be used with flammability/explosion-limit estimates to delineate the extent of the hazard zone (Benjamin et al., 2016; SFPE, 2008). For UGS facilities with high-pressure natural gas, the size of fire and explosion hazard zones can be larger than the clustered or co-located infrastructure footprint, especially for facilities with co-located equipment, such as wellheads near gas processing equipment and operations offices. As an example of co-located equipment, we show in Figure 1.2-30 the McDonald Island Turner Cut station, which has two rows of wells on 25 ft spacing and operations and office space within 50 ft (15 m) of gas processing facilities within the same elevated structure.

Figure 1.2-30. Aerial view of the McDonald Island Turner Cut station showing control room (SW end of central structure) and gas processing facilities (NE end of central structure) and two WSW-ENE trending lines of wells on 25 ft (7.6 m) spacing on either side (north and south) of the central structure.

The area of hazard associated with damage to infrastructure will depend on the mode of failure, time to ignition, environmental conditions at failure point, and meteorological variables. For example, ignited releases can produce pool fires, jet flames, vapor cloud fires, or fireballs, all of which behave differently and exhibit markedly different radiation characteristics. The thermal radiation hazards from hydrocarbon pool fires depend on a number of parameters, including the composition of the hydrocarbon, the size and shape of the pool, the duration of the fire, its proximity to the object at risk, and the thermal characteristics of the object exposed to the fire (Smith et al., 2011; Jo and Ahn, 2002).

Accidental release of hydrocarbon vapors or intentional release (e.g., blowdown) of unwanted gas can result in large turbulent diffusion flames and flares (Dryer et al., 2007; Montiel et al., 1996; Sklavounos and Rigas, 2006). Thermal radiation from flares and

turbulent flames can represent substantial hazard to personnel, equipment, and the environment. The base diameter of a flare stack, height of the stack, and composition of the burning substance are important variables in determining the radiation from turbulent jet flames. Horizontal jet dispersion models that characterize the concentration profile and fire models that characterize the radiative heat flux can estimate the ground area (hazard zone) affected by credible failure scenarios. For the purposes of this section, any and all infrastructure located within the hazard zone will be considered to be a total loss.

Under high leak rates, the downwind concentrations can be larger than the flammability or explosions limits. Flammability limits refer to the range of compositions, for fixed temperature and pressure, within which exothermic chemical reactions are possible. Flammability limits are given in terms of fuel concentration (by volume) at a specified pressure and volume. The lower flammability limit for pure methane is 4.4% (percent volume of air), while the upper flammability limit is 16.4%. For comparison, the lower and upper flammability limits of pure ethane are 3% and 12.4%, respectively.

If the leak rates are very high, then the downwind concentrations can be larger than the lower flammability limits. Results indicate that the C/Q contours (white contours in Figure 1.2-27) extend well beyond the extent of the storage facility (marked in black). This implies that the size of the hazard zone can be much larger than the infrastructure footprint, and that LOC failure consequences can be potentially very large.

This discussion of the high risk to UGS infrastructure associated with severe acute LOC incidents within the footprint of the UGS facility points to the need for clearly establishing the extent of the hazard zone. Design simulations and characterizing hazard zones at current facilities would allow development of safer site layouts and LOC risk mitigation for existing sites, e.g., through minimization of leakage and ignition sources. Buffer zones and sufficient spacing between potentially leaky components, along with open spaces between buildings, mitigate on-site LOC infrastructure risk by providing space for leaking gases to flow and disperse.

1.2.9 Risk to Underground Sources of Drinking Water (USDW) of UGS Failures

Stray gas migration into resources such as underground sources of drinking water (USDWs) associated with the oil and gas industry in general, rather than the UGS industry in particular, have been well documented across the United States. An example of a nationally recognized oil and gas stray gas migration case called the “Bainbridge Incident” occurred in Bainbridge Township of Geauga County, Ohio, in 2007 (Bair et al., 2010). Figure 1.2-31 is a downhole color photo of a stray gas impact to a domestic water supply documented during the Bainbridge Incident investigation (Bair et al., 2010). A total of 26 domestic water wells were impacted by this incident. This type of impact was caused by what is called “annular overpressurization.” Annular overpressurization occurs when the uncemented or poorly cemented annular space behind the production casing fails and allows high-pressured natural gas to migrate into the uncemented or poorly cemented annulus and

enter into formations of lower hydrodynamic pressure, such as groundwater aquifers (Harrison, 1985). Figure 1.2-32 illustrates the potential pathway for stray gas migration in an overpressurized situation (Harrison, 1985). See also Figure 1.2-1 for pressure profiles that are relevant to Figure 1.2-32. In order to fully investigate and document a gas migration incident with a USDW, access to the USDW is necessary. Stray gas migration cases associated with UGS operations with impacts to USDW have not been well documented, but obviously have occurred (e.g., Araktingi et al., 1984). Without having direct access to monitoring wells or private, domestic water wells, determining whether USDW has been contacted by storage gas may be somewhat problematic. The main impact of methane is dissolution into USDW, and potential exsolution during use in homes or business, resulting in fire or explosion hazard. Other impacts can occur from components such as benzene that have maximum contaminant levels and which may be associated with the leaking natural gas from the reservoir.

Historic UGS Migration Issues in California

Evans (2009) documented a number of incidents of storage gas migration in California. Figure 1.2-22 lists the different storage gas migration incidents in California, with some that reached the surface and could have impacted USDWs (Evans, 2009). Numerous cases of stray gas migration to the surface (from both oil and gas and depleted storage fields) in California have been documented over the years due to failure and leakage of old wells. The Montebello UGS field had storage gas leaking to the surface along old oil and gas wellbores that had been drilled in the 1930s, and this storage facility was abandoned due to these gas leaks (Chilingar and Endres, 2005). The Playa del Rey oilfield, located in the Marina del Rey area of the Los Angeles Basin, was converted to underground gas storage in 1942 (Chilingar and Endres, 2005). Storage gas from the field has been leaking along old wellbores for a number of years, and typically this gas migrates into a shallow gravel deposit located several hundred feet below the surface (Chilingar and Endres, 2005). This storage gas migration from the Playa del Rey UGS is a documented case of storage gas impacting a groundwater aquifer in California. This permeable gravel aquifer can act to conceal the true magnitude of storage gas migration hazards (Chilingar and Endres, 2005).

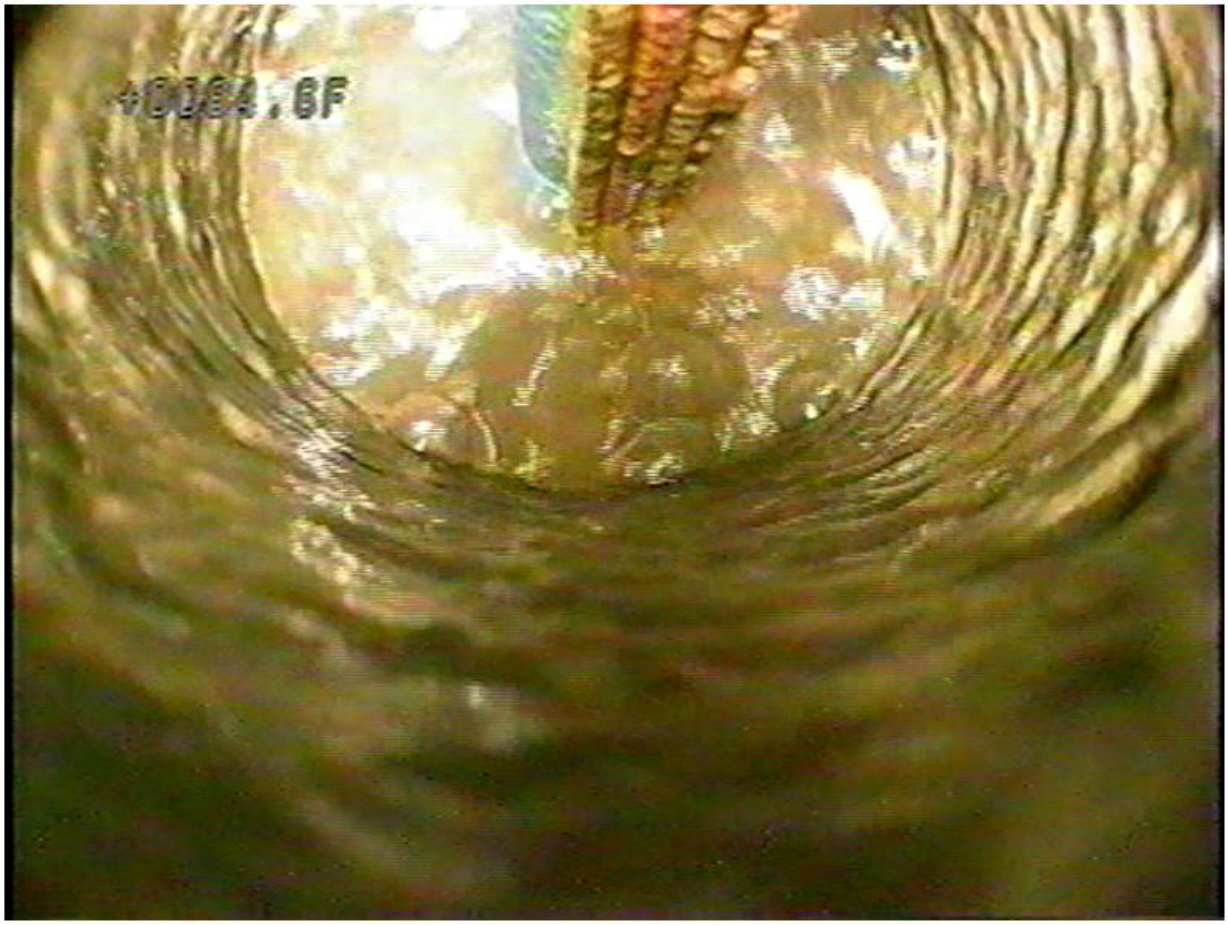


Figure 1.2-31. Example of stray gas migration impact to a USDW during the "Bainbridge Incident" (Bair et al., 2010).

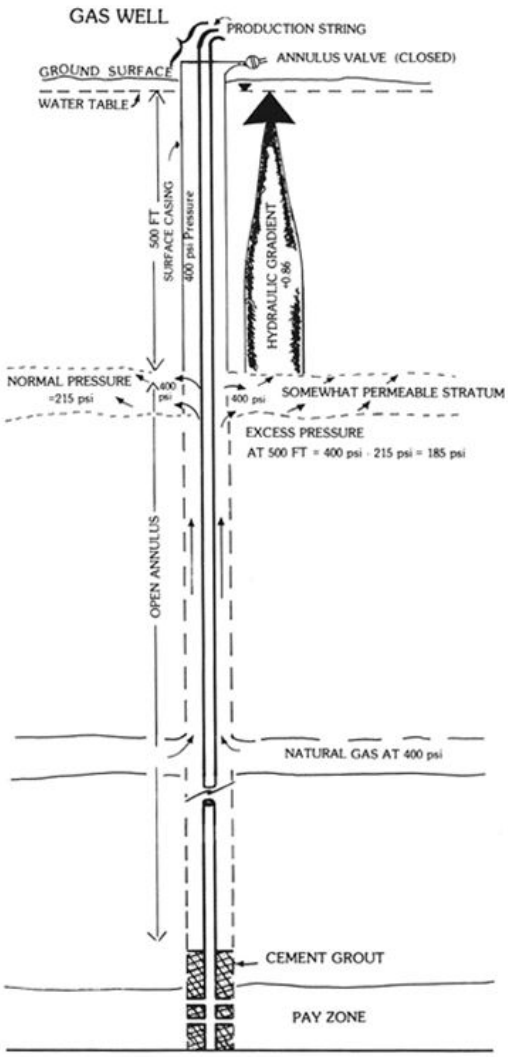


Figure 1.2-32. Example of an annular overpressurization scenario (Harrison, 1985).

1.2.10 Findings, Conclusions, and Recommendations

1.2.10.1 Overall Failure Frequency of UGS

Finding: Gas storage has been carried out in California for over 60 years at around 20 different sites. Several of the facilities have had serious LOC incidents. The most problematic of these sites have been closed and are no longer storing gas. Of the 12 sites open today, seven have incidents recorded in the literature. Although possibly artifacts of reporting or

the fact that California's larger facilities are larger than the worldwide average, the failure rate of UGS in California appears to be higher than the worldwide failure frequency, which is about the same or lower than the failure frequency of oil and gas extraction operations (Evans, 2009).

Conclusion: Analysis of historic failure-rate statistics of California's UGS facilities points to a need for better risk management and improvement in regulations and practices. The Steering Committee views the new regulations proposed by DOGGR as a major step forward to reduce the risk of underground gas storage facilities, provided they are consistently and thoroughly applied and enforced across all storage facilities. In the future, careful re-evaluation of failure statistics, based on ongoing reporting and evaluation of incidents, can help determine whether and to what degree incident reductions have indeed been realized. (See Conclusion 1.1 in the Summary Report.)

Recommendation: At regular intervals in the future, DOGGR should assess—by re-analyzing incident reports—whether the frequency of UGS LOC incidents and other underground gas storage failures in California has actually been reduced. DOGGR should use these statistics to inform auditing processes for regulatory effectiveness. (See Recommendation 1.1 in the Summary Report.)

1.2.10.2 Focus on Subsurface

Finding: Queries of the database compilations of UGS incidents in California show that well-related leakage is by far the most common failure mode for LOC incidents in this state (Evans and Schulz, 2017). In contrast, compilations of UGS failures worldwide suggest that LOC incidents at UGS facilities worldwide are four times more likely to involve above-ground infrastructure (valves, pipes, wellheads, compressors, and other systems) as compared to incidents involving wells (Folga et al., 2016). It appears that California's subsurface LOC incidents are substantially higher than the worldwide average.

Conclusion: Although efforts to reduce LOC incidents should be expended on both surface and subsurface parts of the underground gas storage systems in California, there appears to be a large opportunity to reduce loss-of-containment risk by focusing on reducing subsurface integrity failures, in particular with regard to well integrity issues. Emphasis on subsurface failure modes is consistent with the focus of many of the requirements in DOGGR's interim and draft final regulations. (See Conclusion 1.2 in the Summary Report).

1.2.10.3 Require Tubing and Packer

Finding: In California, DOGGR regulates UGS wells and until now has not required the use of tubing and packer (two-point failure requirement) in UGS wells. Although this is how most UGS wells are operated in the U.S., it is inconsistent with the U.S. EPA's UIC program, which generally requires injection wells to utilize a tubing and packer configuration. But because UGS is specifically excluded from the UIC program, no such federal requirement

exists. The new proposed DOGGR regulations, planned to take effect January 1, 2018, will require a two-point failure configuration for all UGS wells. By the exclusion of UGS from the UIC program, UGS wells have not been required to conform to the two-point failure requirement, resulting in widespread operation of UGS wells that produce and inject fluid through the A-annulus, with the casing serving as the only barrier between high-pressure gas and the environment, including along regions of casing without cement between the outside of casing and the borehole wall. If the SS-25 well at Aliso Canyon had been operated using tubing and packer for production and injection, the hole in the casing, suspected to have been caused by corrosion, would not have caused gas to escape to surface in the 2015 Aliso Canyon incident, because there would have been no reservoir pressure support and gas supply to the A-annulus to feed an ongoing blowout (major LOC incident).

Conclusion: We view the requirement in the new DOGGR regulations of a two-point failure configuration for all UGS wells as an important step in preventing major well blowouts and low-flow-rate LOC events. (See Conclusion 1.3 in the Summary Report.)

1.2.10.4 RA of Failure Scenarios

Finding: Compilations of UGS incidents worldwide and in California show that loss-of-containment (LOC) of high-pressure natural gas at UGS facilities often occurs by a chain of events that can be described by a failure scenario, which often involves human and organizational factors (HOFs). Queries of the updated database of Evans and Schultz (2017) show that well-related leakage is by far the most common failure mode for LOC incidents in California.

Conclusion: Failure scenarios involving initiating and multiple contributing events are common experience. Risk assessment and analysis methods and capabilities are well-developed and available from the engineering consulting industry to address failure scenarios in terms of understanding linkages between events, finding mitigating actions, and quantifying likelihood and assessing risk quantitatively and semi-quantitatively.

Recommendation: Operators of UGS facilities should utilize long experience and new and existing data to carry out quantitative risk assessment (what is the risk?) and risk analysis (what are the main sources of risk? How can risk be reduced?).

1.2.10.5 Basis for Failure Frequency Estimates

Finding: Different authors use a different denominator or basis for estimating failure frequency. E.g., some calculate failure rate on a per well basis, while others use per well-yr or per facility-yr.

Conclusion: The number of wells in use at any time over the course of operations of UGS facilities changes. Furthermore, there are abandoned wells that can be an issue for integrity but that are not used for storage. These facts make it difficult to form a meaningful metric for failure frequency using wells as the basis. We prefer to base failure frequencies on a

per facility-yr basis. To rank sites and account for the larger number of wells at some sites, we suggest using a working-gas-capacity (Bcf) normalization, whereby the per facility-yr frequency is multiplied by the ratio of the California-average working gas capacity to the particular site working gas capacity. By this approach, one can account indirectly for the expected larger number of wells at larger sites, and normalize failure frequency to the average size site.

1.2.10.6 Natural Hazards Can Affect Integrity of UGS Facilities

Finding: Some California UGS facilities are located in regions with particular hazards that can affect UGS infrastructure, among which are seismic, landslide, flood, tsunami, and wildfire hazards. The risk arising from these hazards along with monitoring, prevention, and intervention needs, is now being assessed in the risk management plans that DOGGR now requires from each facility. Some natural hazards are more easily evaluated and mitigated than others; e.g., facilities potentially affected by periodic flooding are often protected by dams or placed on elevated land. Earthquake risk, on the other hand, is harder to assess and mitigate. Fault displacement and seismic ground motion can directly affect the surface infrastructure. Fault displacement can also affect wells at depth through shearing of the well casing if the well crosses the plane of the fault. Earthquake risk is a concern in several California facilities, such as Aliso Canyon, Honor Rancho, and Playa del Rey. SoCalGas is currently conducting an in-depth analysis of the risk related to the Santa Susana Fault, including a probabilistic seismic hazard analysis and a probabilistic fault displacement analysis.

Conclusion: Natural hazards can significantly affect the integrity of UGS facilities. (See Conclusion 1.4 in the Summary Report.)

Recommendation: Regulators need to ensure that the risk management plans and risk assessments required as part of the new DOGGR regulations focus on all relevant natural hazards at each facility. In-depth site-specific technical or geological studies may be needed to evaluate potential natural hazards associated with UGS facilities. For some facilities, earthquake risks fall under that category. (See Recommendation 1.4a in the Summary Report.)

Recommendation: Agencies with jurisdiction should ensure that earthquake risks (and other relevant natural hazards) are specifically investigated with in-depth technical or geological studies at all facilities where risk management plans suggest elevated hazard. (See Recommendation 1.4b in the Summary Report.)

1.2.10.7 Protect UGS from Attack

Finding: By analogy with oil and gas pipelines and wells, which have been the subject of numerous terrorist incidents around the world, UGS facilities in California are vulnerable to similar kinds of attacks.

Conclusion: It is well known that UGS facilities store a highly energetic fuel at high pressure, and that high-pressure pipelines of natural gas are ubiquitous at UGS sites. High-pressure pipelines of natural gas provide a source for explosion and fire that may make UGS sites attractive to terrorists or other groups or individuals intent on harm.

Recommendation: UGS sites should carry out a top-to-bottom review of mitigation of the threat of terrorism or other attacks by individuals or groups. Examples of mitigations of this threat include increasing security, decreasing the attractiveness of the facility as a target, maintaining an appropriate degree of confidentiality about operations, improving cyber security to avoid hacking attacks, and locking key valves and controls (Bajpai and Gupta, 2007).

1.2.10.8 Better Emissions Data and On-site Meteorological Stations

Finding: UGS sites in California are not uniformly equipped with meteorological stations or gas monitoring equipment. Bottom-up approaches that employ empirical emission factors are used to estimate emission inventories. These approaches do not provide the spatially and temporally varying emission data that are critical for estimating downwind consequences of leaks from individual UGS sites.

NOAA's Integrated Surface Database (ISD) provides meteorological data; however, the distances between California UGS sites and the closest stations can range from 2 to 25 km. Many UGS facilities are located in an area of complex topography, which can make the available meteorological data unreliable.

Conclusion: Although a range of practical and sophisticated modeling capabilities is readily available, lack of temporal and spatially varying emission data as well as reliable meteorological data make it difficult to accurately estimate the concentrations and dispersion of gas leakage from UGS facilities.

Recommendation: A practical implementation of continuous emission monitoring technology should be deployed at each UGS facility to provide reliable spatially and temporally varying data for analysis[2]. On-site weather stations should be installed at each UGS facility following National Weather Service (NWS) guidelines. These data could be used to generate accurate estimates of dispersion of leaking gases for risk assessment and emergency response purposes using readily available dispersion models.

2. The California Air Resources Board (CARB) implemented regulations effective October 1st, 2017 requiring continuous meteorological conditions at UGS facilities.

1.2.10.9 Risk to UGS Infrastructure from Fire and Explosions

Finding: Large accidental leaks of natural gas can pose a significant threat to people and property due to thermal radiation from sustained fires and collapse of buildings and infrastructure from explosions. Decompression cooling can cause small pipeline leaks to turn into large leaks. Horizontal jet dispersion models that characterize the concentration profile and fire models that characterize the radiative heat flux can estimate the ground area (hazard zone) affected by credible failure scenarios. Leak rates and meteorological data can be combined with flammability/explosion-limit estimates to delineate the extent of the hazard zone for risk assessment purposes.

Conclusion: The size of fire and explosion hazard zones can be larger than the footprints of local surface infrastructure, e.g., a compressor pad, gas-processing facility pad, or the clustered wellheads on pads of multiple deviated wells. This is especially true for facilities with gas processing equipment co-located with office/control facilities. LOC failure impacts to UGS infrastructure are potentially very large.

Recommendation: Hazard zones should be delineated for each UGS facility to focus risk mitigation on elimination of leakage and ignition sources to reduce the likelihood of fire and explosion, and to design surface infrastructure (e.g., buildings and their layout) to reduce the consequences (loss prevention) of fire and explosion if they should occur (safer site-use planning).

1.2.10.10 Impacts of Leakage on USDW

Finding: Stray gas migration from oil and gas operations into USDW has been well documented across the United States. Leakage of natural gas into USDW from UGS operations can occur and typically is caused by the phenomenon called “annular over pressurization.” Most UGS wells are constructed in a manner that results in an open annular space behind the production casing. This annulus is a potential avenue for gas migration from the gas storage reservoir of higher hydrodynamic pressure into formations of lower hydrodynamic pressure, including aquifers (Harrison, 1985).

Conclusion: Storage gas migration into USDW in California has occurred and has been documented in association with the Playa del Rey gas storage field (Chilingar and Endres, 2005). Other gas storage migration incidents into USDW may go undocumented due to the lack of groundwater monitoring wells or lack of reliance on domestic water wells for private water supplies that would detect the presence of stray gas. Storage gas migration to the surface in a number of California gas storage fields has occurred through leakage through faults and abandoned or improperly plugged oil and gas wells (e.g., Honor Rancho and Montebello) (Evans, 2009).

Recommendation: Implement the proposed DOGGR regulations to improve well integrity and require groundwater monitoring wells at UGS sites to detect possible stray gas migration to USDW aquifers.

1.2.10.11 Clustered vs. Dispersed Wells

Finding: UGS facilities developed in California depleted oil (DO) reservoirs utilize mostly vertical wells that are widely dispersed across the field. In contrast, UGS facilities developed in California depleted gas (DG) reservoirs are often deviated with closely spaced and centralized wellheads.

Conclusion: There are tradeoffs in risk management of closely spaced versus dispersed wellheads. Maintenance and observation of the wellheads is facilitated by clustering, but failure of a wellhead (e.g., a burning blowout) in close proximity to other wellheads can lead to multiple wellhead failures.