Long-Term Viability of Underground Natural Gas Storage in California

An Independent Review of Scientific and Technical Information

Chapter 1, Section 1.3
Effects of age and integrity on underground gas storage capacity

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1.3 CAPACITY OF UGS SITES: EFFECTS OF AGE AND STORAGE INTEGRITY

1.3.1 Abstract

The capacity of UGS reservoirs can be affected by the age of the facility through (1) the effects of formation damage and related reservoir processes, (2) the loss of reservoir integrity through well or caprock seal failure. Any unintended impedance to the flow of fluids into or out of a wellbore (reduction in permeability) is referred to as formation damage (Petrowiki, 2017). Age-related processes affecting depleted oil and natural gas reservoirs include formation damage, grain alteration due to partially fluid-supported sediments, changes in reservoir pressure conditions, and changes in fluid contacts within the pore spaces of the reservoir. Of these, the factor with the greatest potential to affect storage capacity is formation damage, as it affects the productivity of a depleted oil and gas reservoir during gas withdrawal. Operators should carry out proactive approaches to identifying, addressing, and properly mitigating formation damage in advance of the reduction in formation permeability to avoid loss of gas storage reservoir capacity.

The majority of the depleted oil and gas fields converted to UGS in California were originally discovered and developed for oil and natural gas production from 1929 to 1958. Consequently, the majority of the wells used for UGS in California are older wells (see Section 1.1) and these have required extensive well work-overs targeting a variety of integrity-related issues, such as quantity and quality of cement and corrosion of casing. Well work-overs themselves can provide inherent risk and have the potential for accidental releases. The age of these wells and historic well construction practices dramatically increase the likelihood for LOC. Five gas storage fields within the Los Angeles area have experienced gas migration issues due to age of the wells, improperly plugged and abandoned wells that served as avenues for gas migration out of the reservoir, and reliance on repurposed gas storage wells. At the depleted Montebello oilfield in Los Angeles, gas had been injected by SoCalGas at a depth of 7,500 feet since the early 1960s (Bruno, 2014). Gas injection ceased in 1986 after significant gas seeps were discovered at the surface within a large housing development above the gas storage reservoir (Khilyuk et al., 2000). Soil-gas analysis had detected the presence of imported and processed storage gas, several homes were purchased and demolished, and soil-gas extraction system was installed (Miyazaki, 2009).

When old wells are taken out of service due to age or integrity failures, the capacity of a gas storage reservoir is impacted unless new gas storage wells are drilled and completed to retain gas storage capacity and deliverability. Regarding effects on capacity of reservoir integrity in depleted oil and gas field storage operations, the initial confining zone/caprock is relatively secure as evidenced by hydrocarbon retention (based on the thick cap that acts as a robust seal in preventing migration from the gas storage reservoir), but the seal can sometimes become degraded over time with repeated pressure and stress cycling. The maximum operational reservoir pressure may need to be reduced to manage reservoir integrity problems, thereby impacting capacity. By assessing gas storage reservoir integrity

using a holistic approach (i.e., utilizing multiple methodologies such as geophysical logging and pressure testing), the number of incidents associated with loss of storage integrity can be dramatically reduced, with the added benefit of maintaining storage capacity.

1.3.2 Historical Use Considerations (e.g., oil and gas production)

1.3.2.1 Introduction and Discussion

This section reviews the history of gas storage facility operations and discusses the effects on capacity of age and storage integrity failures. According to the Energy Information Administration, as of 2015 there were 415 natural gas storage fields in the United States, and approximately 79% of these gas storage fields are in depleted oil and gas reservoirs (Tomastik and Arthur, 2016). The first conversion of a depleted oil and natural gas field to underground natural gas storage (UGS) occurred in Zoar, New York, in June 1916 (National Fuel Gas, 2016). Figure 1.3-1 shows the surface infrastructure of the first gas storage operation in the United States.

Conversion to gas storage of depleted fields commenced after World War II and continued across the United States as the demand for natural gas increased. Many of the wells within these depleted oil and natural gas fields were drilled and completed in the early to mid-1900s. Conversion of these wells to gas storage was not without problems. Most of the well construction and cementing practices at that time were substandard compared with modern drilling and completion technologies and requirements. Due to older well construction and cementing practices followed many decades ago, older wells converted to gas storage undergo extensive well work-overs. Well work-overs can lead to remedial well construction and cementing operations as well as continued well integrity assessment (Figure 1.3-2).

Storage of natural gas in California started in the 1920s when SoCalGas began storing natural gas in large aboveground tanks to meet customer needs (SoCalGas, 2017a). In 1941, the company introduced an approach new to California—underground storage of natural gas in depleted oil and gas fields, with the commencement of underground storage at La Goleta in Santa Barbara County (SoCalGas, 2017a). The majority of the depleted oil and gas fields converted to UGS in California were originally discovered and developed for oil and natural gas production from 1929 to 1958 (ALL Consulting, LLC, 2015). Consequently, the majority of the wells used for underground gas storage in California are older wells (see Section 1.1) and have required extensive well work-overs targeting a variety of integrity-related issues of older wells, such as quantity and quality of cement and corrosion of casing.

Side bar: Description of the 2015 Aliso Canyon incident: SS-25 well blowout and kill attempts

Introduction

The 2015 Aliso Canyon incident was a subsurface blowout of a gas storage well (SS-25) that breached to surface and leaked approximately 100 thousand tons (~5 Bcf) of methane into the atmosphere over nearly four months without igniting (Conley et al., 2016). Only the 2004 Moss Bluff cavern storage well blowout exceeded the size of the 2015 Aliso Canyon incident, but the Moss Bluff natural gas ignited converting the methane to CO_2 making the Aliso incident the largest release of methane to the atmosphere in U.S. UGS history (Conley et al., 2016). The total amount of natural gas leaked was approximately 6% of the working gas capacity of the reservoir. This severe loss-of-containment (LOC) incident led to the evacuation of several thousand families from the Porter Ranch neighborhood downslope of the SS-25 well, families who either experienced health impacts or were avoiding potential health impacts.

In this brief side bar, we describe the main elements of the incident with an emphasis on the physical processes occurring in the well before and during attempts to kill the well. The account is relevant to risk because it illustrates a case in which the failure scenario was very difficult to address, which points out the value of risk mitigation and avoidance of failure scenarios. We do not discuss the emergency response, or impacts of the incident on the community, the environment, or the larger UGS industry, the full extents of which have yet to play out. We emphasize that the full root-cause analysis of the 2015 Aliso Canyon incident has not been published, so the account below is tentative but based on available records, documentation, and inference.

Background

The SS-25 well was one of 115 operational wells at the Aliso Canyon UGS facility at the time of the blowout. As with a bit fewer than half of the wells at Aliso Canyon, SS-25 was a re-purposed oil well with the original production casing from its construction in 1953. The SS-25 well was converted to use as a UGS well in 1973, and the last work-over of the well was in 1979, at which time a failed subsurface safety valve (SSSV, aka downhole safety valve (DHSV)) was removed. At some point, slots or ports were created likely for use of a sliding sleeve valve (SSV) at this location (depth of 8,451 ft) connecting the tubing and A-annulus (Figure SB-1) (Interagency Task Force on Natural Gas Storage Safety, 2016, p. 19).

The direct connection between the tubing and the A-annulus of this well is not a unique feature of the SS-25 well, but is in fact a common feature of UGS wells. This configuration in which both tubing and annulus are used for injection and production is non-standard in the oil and gas industry (outside of UGS) and not allowed under the U.S. EPA Underground Injection Control (UIC) program because it causes reliance on a single barrier (the casing) to hold the high pressure of the gas in the well. Normal oil and gas and wells (and injection wells in the UIC program) only produce (or inject) fluid through the tubing, and they utilize a packer to maintain isolation between the high-pressure of the reservoir and the A-annulus. By this standard approach, the A-annulus serves as a region in which pressure can be monitored and anomalies investigated, while the casing serves as a secondary barrier.

Blowout

Gas leakage was detected to be occurring from out of the ground on the hillsides below the ridge-nose location of the wellhead of SS-25 on or about October 23, 2015. Although it was considered at the time to be a straightforward operation to kill the well, ultimately eight unsuccessful well-kill attempts would be made between October 24, 2015, and late December by pumping heavy kill fluids and other materials down the well. In early November, attempts to carry out temperature logging, a standard approach to detect and locate subsurface leakage by means of sensing decompression cooling associated with subsurface blowouts, failed because of a blockage of methane hydrate at a depth of approximately 450 ft. (Methane hydrate is a water-methane compound similar to ice that forms at low temperatures in water-methane systems and is a good indicator of gas leakage in wells.) In order to facilitate completion of the temperature log, a coiled tubing rig was set up on November 4, 2015, at the SS-25 well with the goal of injecting hydrate inhibitor (glycol) fluid to wash out the hydrate blockage. A hydrate plug at approximately 450 ft depth was removed by this process.

Temperature and noise logs were obtained by November 8, 2015, and showed that there was no gas flow in the tubing down to 8,435 ft, but gas was flowing in tubing below that depth. It can be inferred from this evidence that gas was flowing up the A-annulus above 8435 ft. At some point in the timeline, a bridge plug was placed in the tubing at a depth of 8,393 ft to allow pressure testing of the tubing to determine its integrity. The tubing was subsequently perforated to connect the tubing and A-annulus above this plug. The methane hydrate plug at 450 ft depth is suggestive of the location of leakage from the A-annulus to the B-annulus (see Figure SB-1). A cooling anomaly at 890 ft depth was detected, suggestive of leakage from the B-annulus to the formation at the base of the surface casing (see Figure SB-1).

On November 13, 2015, one of the multiple top-kill attempts was carried out in which heavy kill fluid was injected. Instead of killing the well, the kill fluid came to surface and, along with high-pressure natural gas from the reservoir, excavated a crater north of the well. By December 22, 2015 following additional kill attempts, the single crater had grown to comprise a large crater on both sides of the SS-25 well approximately 25 ft deep, 80 ft long and 30 ft wide (2,400 sq. ft) (22 m_2) oriented subparallel to the ridge, the likely direction of maximum horizontal stress (Figure SB-2). The craters surrounded the well and thereby allowed the well casing to oscillate from side to side. The extreme motion of the well during the last top-kill attempts in late 2015 led responders to place a bridge-like structure across the craters approximately perpendicular to the ridge to stabilize the casing. From this point forward, the natural gas gushed out of the craters into the atmosphere along with entrained kill and reservoir fluids, although at some point in the timeline a heavy steel screen was placed over the craters in the attempt to catch some of the oily residues entrained with the gas.

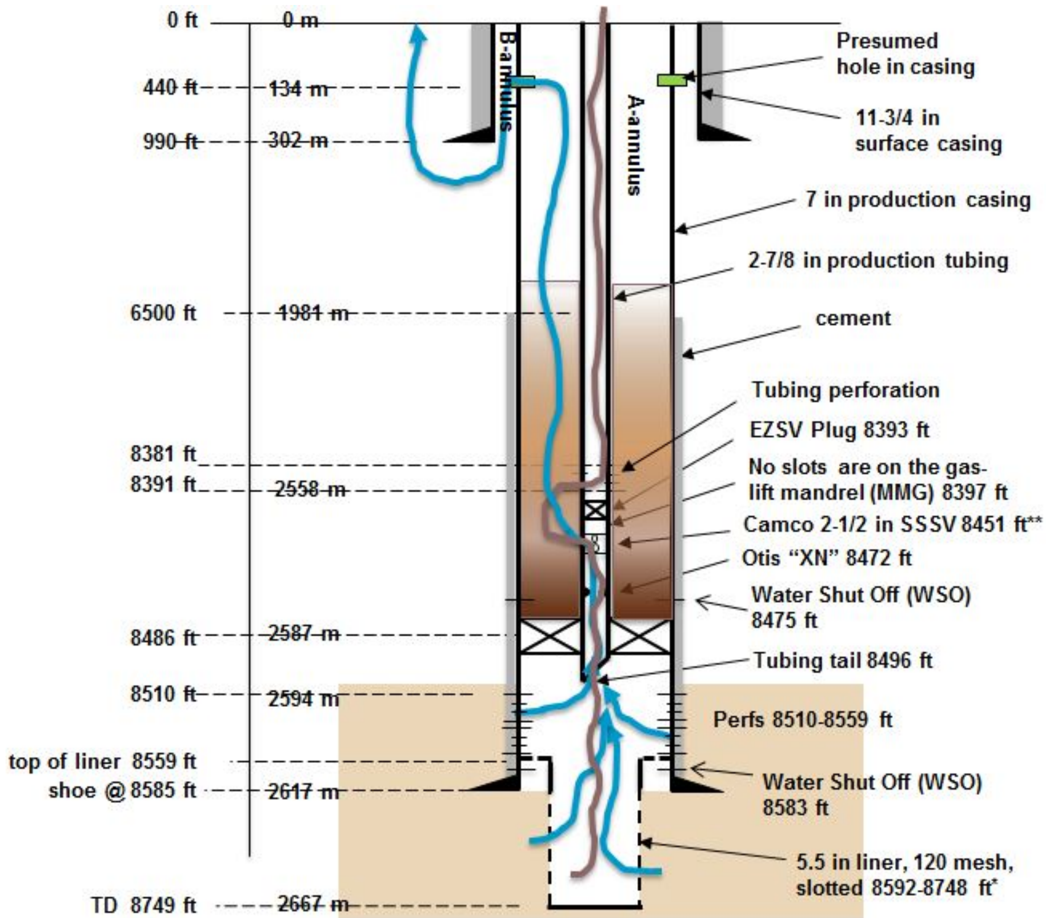

Figure SB-1. Sketch of the SS-25 well (not to scale) showing the complex geometry of gas flow (blue) and kill-fluid flow (brown). In particular, note that the tubing is connected to the A-annulus through slots in the tubing. Note further that at some point during the SS-25 blowout, a plug and tubing perforations were installed in the well at a depth of 8393 ft.

*The 120 mesh liner is believed to be 120 Gauge (0.120 inch).

**This is the location of a subsurface safety valve (SSSV) that was removed decades ago. At the time of the 2015 incident, there were slots in the tubing at this location connecting the inner tubing to the A-annulus, possibly remnants of an inoperable or missing sliding sleeve valve (SSV) installed at some point (Interagency Task Force on Natural Gas Storage Safety, 2016, p. 19).

Figure SB-2. The SS-25 wellhead is shown in the upper right-hand quadrant of this image along with the two craters extending diagonally from the well in the photo. Source: http://www.latimes.com/local/california/la-me-aliso-well-hole-20160115-story.html (Accessed 7/30/17).

Why was the SS-25 well hard to kill?

Simulations indicate the flow geometry within the well made the SS-25 very difficult to kill using top-kill approaches (Pan et al., 2018). In particular, the gas apparently flowed at high velocity through the open ports of inoperable (or missing) sliding-sleeve valve. In order to kill the well by a top kill, kill fluid would need to pool in the A-annulus to a height that would produce pressure high enough to overcome the gas flowing out of the tubing ports. Meanwhile, the only way for kill fluid to accumulate in the A-annulus was for it to exit the tubing through the perforations above the plug at a depth of 8393 ft. However, gas at high velocity was flowing upward in the A-annulus all the while that kill fluid was flowing through the perforations. Simulations show the flowing natural gas in the A-annulus was strongly entraining the kill fluid and carrying it upward in the well. The excavation of the craters is potential evidence of strong kill-fluid returns (Pan et al., submitted).

A relief well (Porter 39-A) milled into the SS-25 well below the packer on February 11, 2016, resulting in a flood of drilling fluid entering the well and reservoir. The high pressure of the drilling mud filled the bottom of the well and "U-tubed" up SS-25 killing the gas blowout within minutes. The SS-25 was subsequently filled with cement and abandoned.

Sources:

Interagency Task Force on Natural Gas Storage Safety (2016)

Denbury engineer:

(http://connect.spe.org/HigherLogic/System/DownloadDocumentFile.ashx?DocumentFileKey=4a50f78c-2906-c4d0-771d-0d9cb697470a (accessed 7/30/17)

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Pan, L., Oldenburg, C.M., Freifeld, B.M., and Jordan, P.D., Modeling the Aliso Canyon underground gas storage well blowout and kill operations using the coupled well-reservoir simulator T2Well, J. Petrol. Sci. and Eng., Vol. 161, pp 158-174.

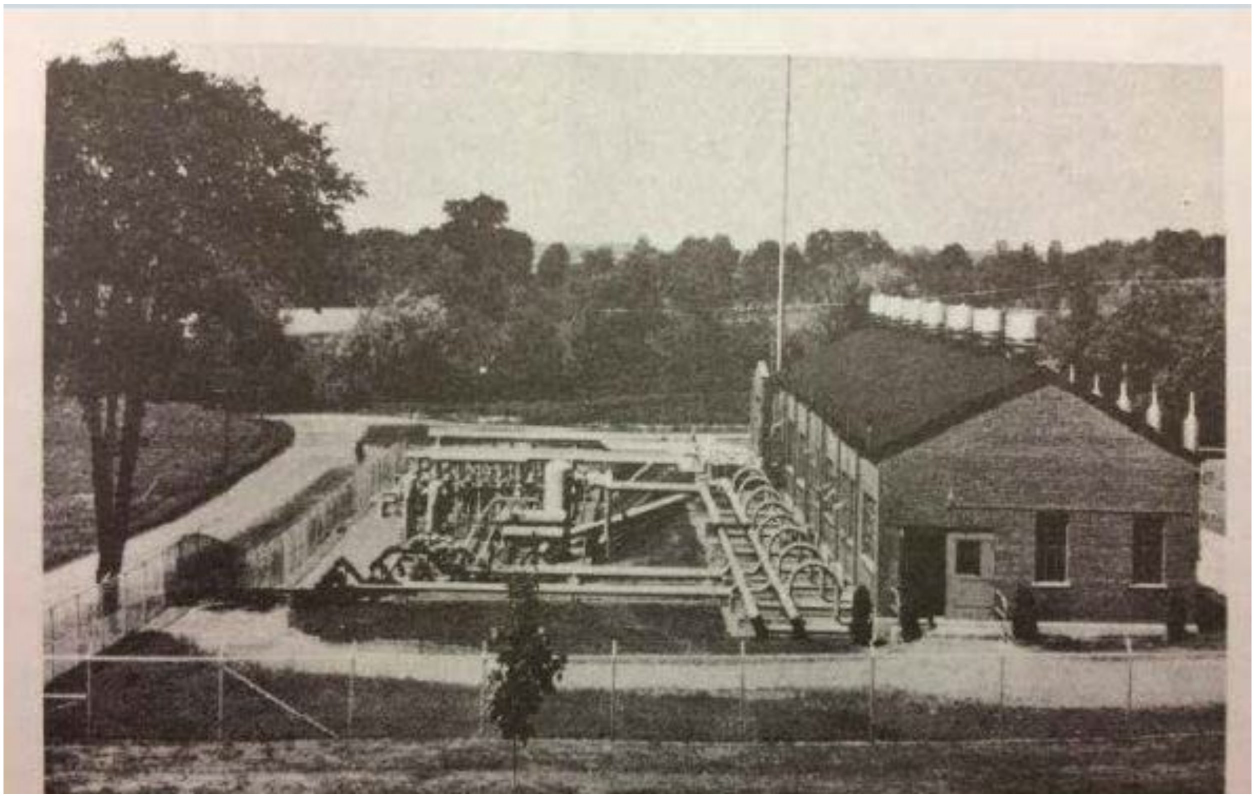

Figure 1.3-1. Photo of the nation's first underground gas storage field (Source: National Fuel Gas, 2016).

Figure 1.3-2. Example of a well work-over underway (Source: ALL Consulting, LLC, 2016).

1.3.3 Underground Gas Storage Capacity Can Be Affected by the Age of UGS Operation

1.3.3.1 Introduction and Discussion

Approximately 80% of the wells in United States UGS sites were completed in the 1970s or earlier, and have been exposed to decades of physical and mechanical stresses (Interagency Task Force on Natural Gas Storage Safety, 2016). The storage capacity of a UGS field converted from a depleted oil and natural gas reservoir can be affected by a number of different factors, including (GWPC and IOGCC, 2017):

1. Formation compaction and damage from the original oil, produced water, and natural gas extraction (i.e., formation damage);
2. Grain alteration due to partially fluid-supported sediments;
3. Changes in reservoir pressure conditions; and
4. Changes in fluid contacts within the pore spaces of the reservoir

The factor with the greatest potential to affect storage capacity is formation damage, as it affects the productivity of a depleted oil and gas reservoir during gas withdrawal. Formation damage is a generic term that refers to the impairment of the permeability of hydrocarbon-bearing formations by various adverse processes (Anyadiegwu and Muonagor, 2013). Formation damage is usually caused by physico-chemical, chemical, biological, hydrodynamic, and thermal interactions of the porous formation with particles and fluids and mechanical deformation of the reservoir under stress and fluid shear (Anyadiegwu and Muonagor, 2013). Such causes can include: (1) Cold fluid injection; (2) Cooling by gas expansion; (3) Incompatible/contaminated fluid invasion; and (4) High flow rate through the formation (Sutton and Roberts, 1974).

According to Benion and Jones (1994) formation damage falls into four broad categories based on the mechanism of its origin. They include:

1. Mechanically induced formation damage (phase trapping, fines migration, and solids entrapment);

2. Chemically induced formation damage (clay swelling and deflocculating, wax deposition, solids precipitation, acid sludge, stable emulsions, chemical adsorption, and wettability alternation);

3. Biologically induced formation damage (bacterial action); and

4. Thermally induced formation damage (elevated or reduced borehole temperatures).

Formation damage affects the deliverability of the gas storage reservoir by causing a reduction in the reservoir permeability and an increase in the well skin factor, which causes greater resistance to flow and reduces gas deliverability from the storage reservoir (Anyadiegwu and Muonagor, 2013). The zone with an altered permeability is called “skin” and its effect on the pressure or flow behavior of a well is called the “skin effect” (Hurst et al., 1969). The skin factor is a dimensionless pressure drop caused by flow restriction in the near wellbore environment (Petrowiki, 2017). Figure 1.3-3 is a graph showing the effects of skin on the deliverability of natural gas from a gas storage reservoir. The deliverability of working gas decreases as a result of skin increase, which indicates formation damage (Tureyen et al., 2000; Anyadiegwu and Muonagor, 2013).

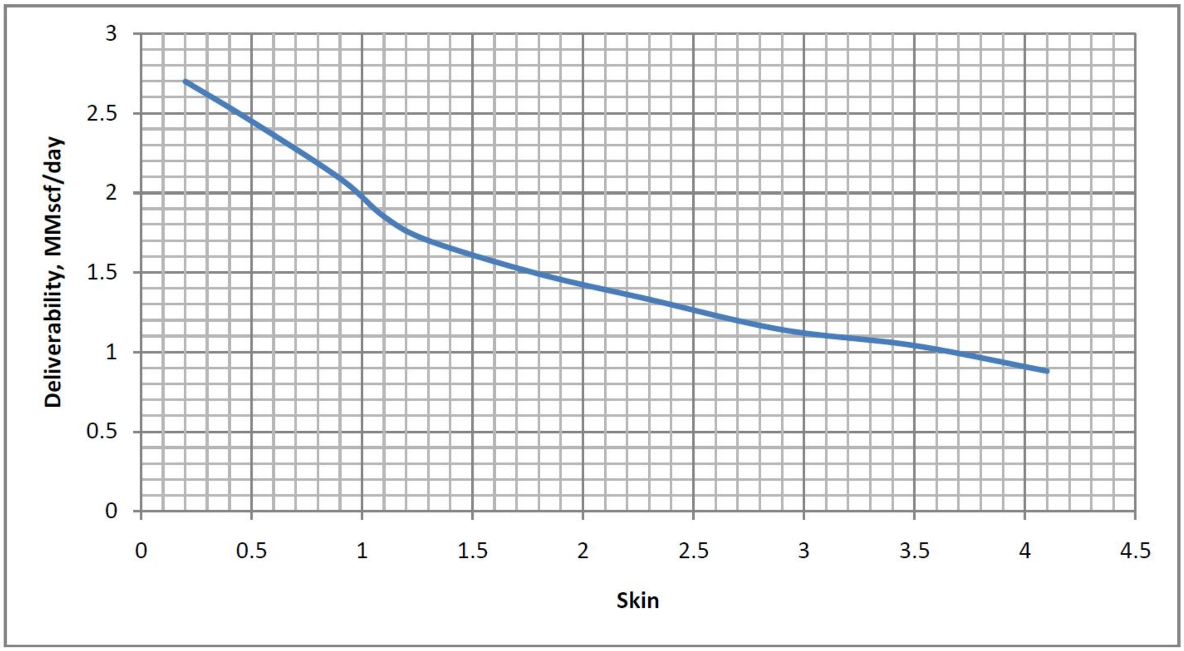

Figure 1.3-3. Plot of gas deliverability against skin for an underground gas storage reservoir (Anyadiegwu and Muonagor, 2013).

1.3.3.2 Addressing Formation Damage

Finding: The gas storage reservoir and its ability to deliver gas can be altered due to formation compaction and damage from long-term oil, produced water, and natural gas extraction resulting from grain alteration, changes to reservoir pressure conditions, and changes to the fluid contacts within the underground gas storage field (GWPC and IOGCC, 2017). Formation damage causes reduction in gas storage reservoir permeability which leads to a decrease in deliverability that dramatically impacts the effective capacity of the underground gas storage field (Anyadiegwu and Muonagor, 2013).

Conclusion: Because formation damage is more likely in older wells with long histories of production, UGS capacity can be affected by the age of the wells at the UGS facility and its history of operations.

Recommendation: Operators should carry out proactive approaches to identifying, addressing, and properly mitigating formation damage in advance of the reduction in formation permeability to avoid loss of UGS reservoir capacity. Being aware of formation damage implications during drilling, completion, injection, and production operations can help in substantially reducing formation damage and enhancing the ability of a well to inject and withdraw storage gas.

1.3.4 Underground Gas Storage Capacity Can Be Affected by Incidents of Reservoir Integrity Failure

1.3.4.1 Introduction and Discussion

Gas storage reservoir integrity can be defined by the geological and geomechanical conditions that are present within the storage reservoir that allows for safe operations beyond the wellbore (Katz and Tek, 1981; Interagency Task Force on Natural Gas Storage Safety, 2016). Loss of reservoir integrity, which results in subsurface leakage (formally LOC, but not necessarily LOC to the atmosphere), has a major impact on the capacity of the gas storage reservoir. Fundamentally, gas storage leakage from the reservoir carries two different types of risks (Folga et al., 2016):

1. The storage gas may migrate from the reservoir geologic structure, reaching drinking water aquifers and/or the surface, which represents a potentially significant risk to human health, safety, and the environment.

2. The stored gas may migrate from the storage reservoir geologic structure into overlying or adjacent porous and permeable formations and become nonrecoverable, which represents an economic risk.

Likely pathways for gas migration from the gas storage reservoir are caused by failure of vertical and/or lateral containment, which can be caused by artificial (well) penetrations, naturally occurring faults or fracture systems that may be transmissive, and compromising of the confining zone/caprock sequence due to reservoir overpressurization and/or overfilling of the structural or stratigraphic geologic spill points (Evans, 2008; Bruno, 2014; API, 2015; Folga et al., 2016; Interagency Task Force on Natural Gas Storage Safety, 2016; GWPC and IOGCC, 2017). In general, the loss of well integrity remains the primary factor in underground gas storage LOC incidents, with failure of subsurface reservoir integrity and surface operations being important secondary contributors (Evans, 2008; Bruno, 2014; API, 2015; Interagency Task Force on Natural Gas Storage Safety, 2016).

Bruno (2014) identified a number of potential leakage mechanisms associated with underground gas storage reservoirs and included the following:

1. Pore space/capillary pressure/permeation (caprock matrix)

2. Fault plane/fracture transmission (structural)

3. Induced fracturing, faulting, and bedding slip (geomechanical)

4. Dissolution channels/shrinkage cracks (geomechanical)

5. Overpressurization of the confining zone/caprock

6. Leakage along poorly cemented, improperly plugged, or abandon and unplugged wells.

Figure 1.3-4 further illustrates the additional mechanisms for leakage associated with underground gas storage reservoirs.

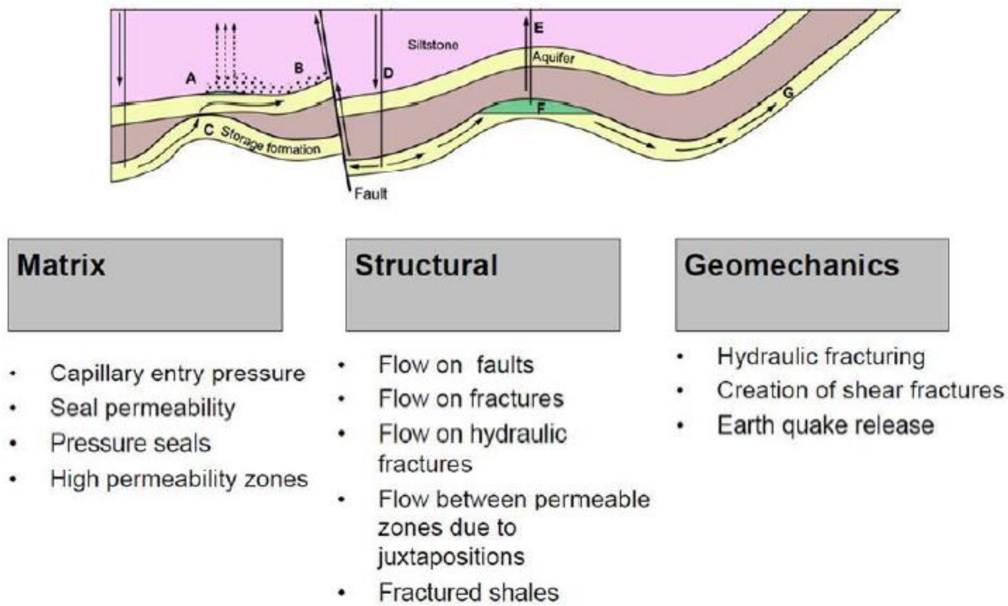

Figure 1.3-4. Identification of the leakage factors associated with gas storage reservoirs. Potential leakage pathways and mechanisms are indicated by the letters A-G as follows: (A) Gas leaks out of the reservoir through an eroded gap (missing local seal), (B) the gas pressure accumulated in the above-zone saline reservoir exceeds the capillary entry pressure in the regional seal and leaks upwards, (C) Gas leaks upwards along a conductive normal fault, (D) Gas leaks up a poorly cemented annulus of a UGS injection well, (E) Gas leaks up a poorly plugged abandoned well, (F) regional groundwater flow transports dissolved gas out of the structural closure, and (G) once out of the closure, groundwater transports gas to surface springs and into the atmosphere. (From IPCC (2005), but see also Nygaard (2012) and Bruno (2014)).

With depleted oil and gas field storage operations, the initial confining zone/caprock seal is relatively secure, but can sometimes become degraded over time with repeated pressure and stress cycling (Bruno, 2014). There have been 22 storage gas leak occurrences from a total of 485 porosity-storage facilities worldwide that could be attributed to natural gas migration through the confining zone/caprock sequence, corresponding to about 10% of all leakage occurrences investigated (Evans and Schultz, 2017). Evans and Schultz (2017) identify these failure mechanisms to include:

1. Failure of the confining zone/caprock sequence itself
2. Undetected or incorrectly characterized faults or fractures in the sequence
3. Combination of caprock failure and seal-bypass mechanisms.

Historically, California has been responsible for 18% of the underground gas storage incidents at depleted oil and gas fields due to gas migration to the surface along old wells and faults (Folga et al., 2016). California has a long history of oil and natural gas exploration dating back into the late 1800s, with many thousands of wells having been drilled across the state, often at very high densities prior to the existence of regulatory frameworks (Evans, 2008). Many oil and gas wells are not accurately located, and many well locations are not known at all. The majority of these old oil and gas wells have no, or at best, deteriorating casings and cement, and large numbers of these wells are unplugged or improperly plugged and abandoned (Evans, 2008). The Los Angeles area has been an area of intense hydrocarbon exploration and production since the late 1800s, with over 70 oilfields having been discovered, most within the early part of the 20th century (Bruno, 2014). Figure 1.3-5 is an example of oil and gas development in the Los Angeles area in early 1900s.

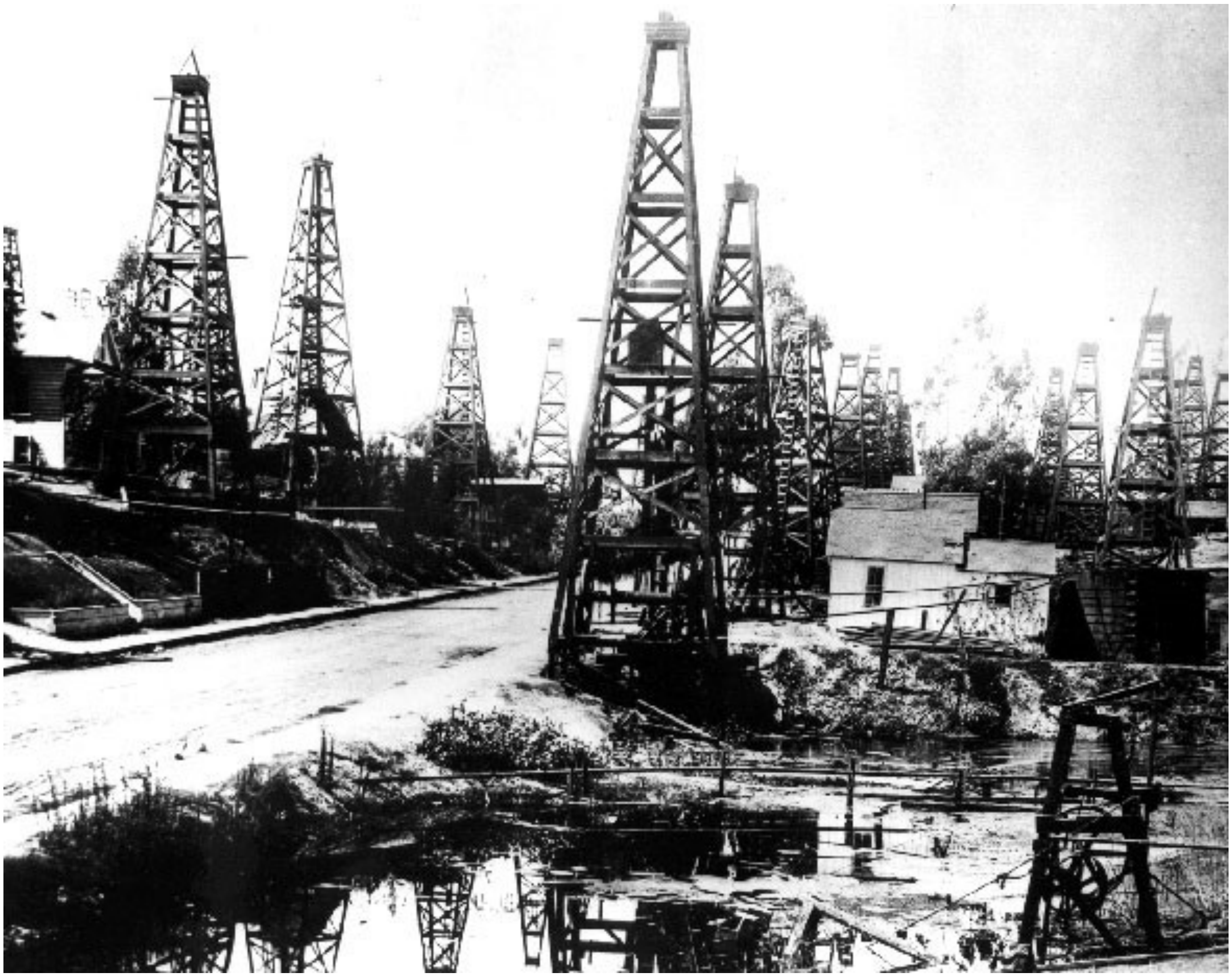

Figure 1.3-5. Photo of First Street, Los Angeles City oilfield, circa 1900 (Source: http://www.conservation.ca.gov/dog/photo_gallery/historic_mom/Pages/photo_04.aspx, accessed September 1, 2017).

Artificial well penetrations pose one of the greatest risks to reservoir integrity and loss of gas storage capacity, particularly in some of the southern California UGS fields, where thousands of poorly documented wells now lie beneath densely populated urban areas (Evans, 2008; Bruno, 2014). According to Bruno (2014), five gas storage fields that have operated in the Los Angeles area have experienced gas migration problems to the surface due in part, perhaps, to confining zone/caprock integrity issues and old wells. These include: Castaic & Honor Rancho, Playa del Rey, El Segundo, Whittier, and Montebello UGS fields (three of which have now been closed and abandoned—El Segundo, Whittier, and Montebello). Figure 1.3-6 shows the location of four of these five gas storage fields that experienced gas migration problems to the surface in the Los Angeles Basin area.

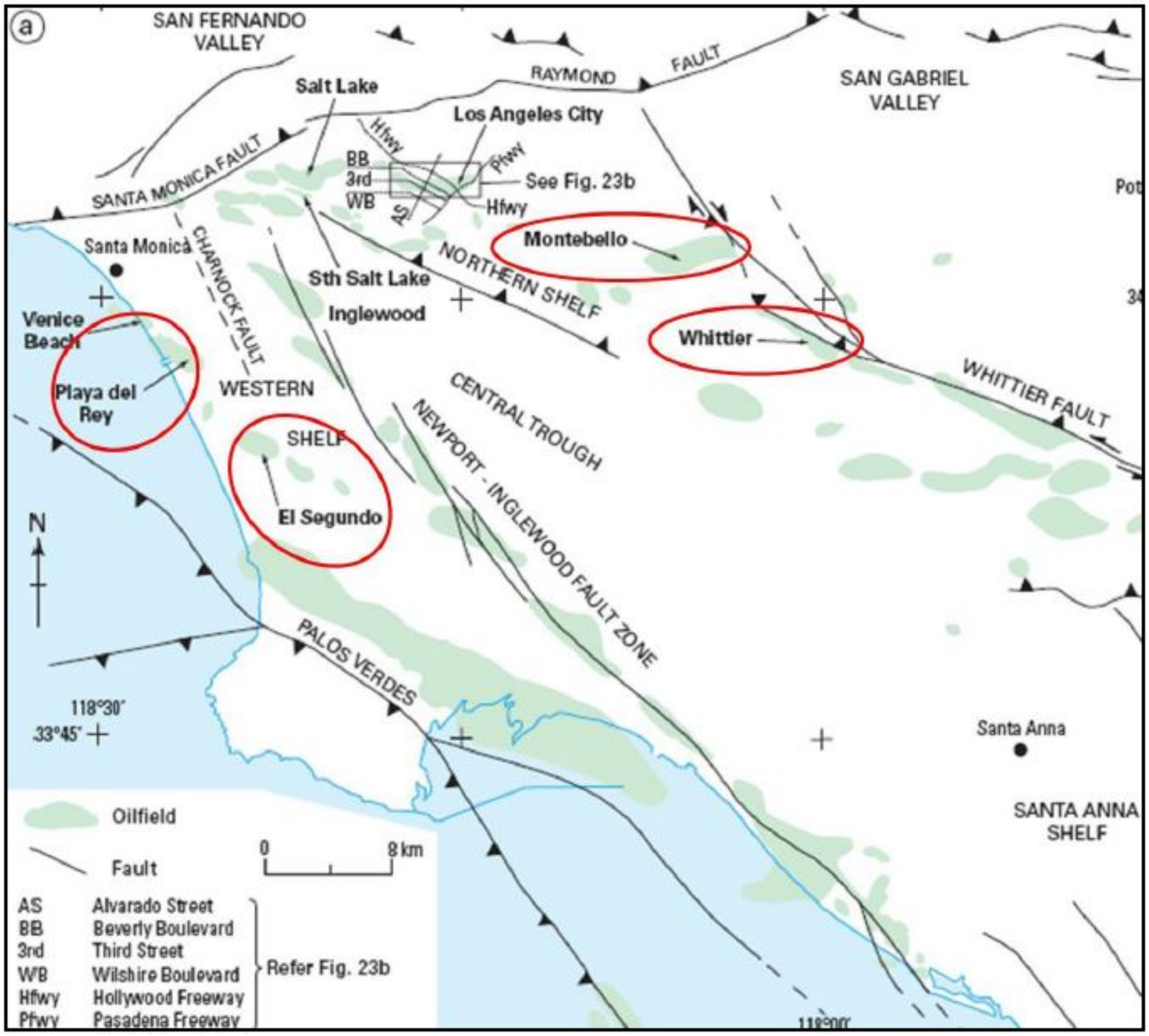

Figure 1.3-6. Map showing the location of four of the five gas storage fields with known surface leakage in the Los Angeles Basin area (Bruno, 2014).

The capacity of a gas storage reservoir can also be impacted by loss of old wells due to age, well construction, and well integrity failure (e.g., King and King, 2013). As these old wells are taken out of service and properly plugged and abandoned, new gas storage wells will need to be drilled and completed to retain existing gas storage capacity and deliverability. With the advent of horizontal drilling, many new gas storage wells are being drilled and completed horizontally within the gas storage fields throughout the U.S., which can dramatically increase capacity and deliverability of working gas within a gas storage reservoir.

With DOGGR's proposed regulatory changes that transition gas storage production from both production casing and tubing gas withdrawal and injection to injection and withdrawal through tubing and packer only (see Section 1.6), there will be a reduction in effective gas storage capacity and deliverability because of the reduced effective diameter of the well. To address these proposed regulatory changes, California gas storage operators will need to consider drilling and completing a number of new gas storage wells or alter existing well construction operations to increase capacity and deliverability. Currently, many of the wells in the gas storage fields in California utilize larger diameter production casings and a liner set across the storage formation. Injection and withdrawal operations are typically through smaller diameter tubing (such as 2-3/8" or 2-7/8"). If this is the case in most of the storage fields in California, larger diameter injection/withdrawal tubing could be used to increase injection and deliverability from the gas storage reservoirs.

1.3.4.2 Need for Stronger Regulations to Avoid Loss of Storage Capacity

Finding: Loss of reservoir integrity is a failure of UGS that results in closing of UGS reservoirs, or shutting in of certain wells, or requirement to operate at lower pressure. California UGS has experienced multiple LOC incidents due to reservoir integrity failure, which resulted in storage gas migration through old oil and gas wells back to the surface.

Conclusion: Gas storage reservoir integrity can be defined by the geological and geomechanical conditions that are present within the reservoir that allow for safe operations beyond the wellbore. Likely avenues for gas migration from the reservoir are caused by failure of vertical and/or lateral containment, which can be caused by artificial (well) penetrations, naturally occurring faults or fracture systems that may be transmissive, compromising of the confining zone/caprock sequence due to reservoir overpressurization, and overfilling of the structural or stratigraphic geologic spill points (GWPC and IOGCC, 2017). Fundamentally, UGS reservoir integrity carries two different types of risks: the release of gas from the storage reservoir that reaches aquifers and/or the surface, or migration of storage gas from the reservoir into overlying or adjacent geologic formations, where it becomes nonrecoverable.

Recommendation: More stringent underground gas storage regulations should be developed to require more technical, geologic, and engineering data to better characterize the gas storage reservoir. By assessing gas-storage-reservoir integrity using a holistic approach (i.e., utilizing multiple approaches such as geophysical logging and pressure testing), the number of incidents associated with gas-storage-reservoir-integrity failure can be dramatically reduced with the added benefit of avoiding loss of storage capacity.