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REGULAR ARTICLE OPEN ACCESS

Review and analysis of historical leakages from storage salt caverns wells

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Abstract. Twelve incidents involving well casing and/or cement leaks in the salt caverns storage industry are described. These incidents occurred at the following storage sites: Eminence salt dome, Mississippi; Elk City, Oklahoma; Conway, Kansas; Yoder, Kansas; Mont Belvieu, Texas; Teutschenthal/Bad Lauchstädt, Germany; Clute, Texas; Mineola, Texas; Hutchinson, Kansas; Magnolia, Louisiana; Boling, Texas; Epe, Germany. Mechanisms leading to a casing leak and consequences are discussed. In most cases, a breach in a steel casing occurred at a depth where a single casing was isolating the stored product from the geological formations. The origin of the breach was due in most cases to poor welding/screwing conditions and corrosion, or excessive deformation of the rock formation. In this, the age of the well is often influential. In many cases, the leak path does not open directly at ground level; fugitive hydrocarbons first escape and accumulate in the subsurface prior to migrating through shallower horizons and escaping at ground surface. A pressure differential between hydrocarbons in the borehole and fluids in the rock mass favours fast leak rates. A wellhead pressure drop often is observed, even when the stored product is natural gas. The incidents described suggest that thorough monitoring (tightness tests) and a correct well design would lessen considerably the probability of a casing leak occurring.

1 Introduction

Prompted in part by projects related to carbon dioxide (CO_2) sequestration in which long-term tightness is crucial, there has been an increasing interest in the tightness of hydrocarbon (oil and gas) storage wells. In addition, high profile incidents, such as the 2015 Aliso Canyon blow-out, in California, have raised public awareness. The Aliso Canyon incident involved a massive gas leak from a depleted reservoir natural gas storage facility, the cause of which was a failure of the production tubing in a production well at around 2577 m (8450 ft) and consecutive leak from the well at a shallower depth (around 134 m, or 440 ft; California Council on Science and Technology, 2018).

This paper focuses on hydrocarbon storage facilities using salt caverns, access to which in most cases is through a single well or, more rarely, through a number of wells. These wells are of similar design and construction to those used in the oil and gas industry. Salt caverns are almost perfectly tight and for this reason, as in most pressure vessels, the tightness problem is with the "piping" connecting the cavern to surface, *i.e.*, the completion (casing and tubing) and cementation of the wells.

Research and innovation on cementation have been ongoing since the early days of oil and gas production. However, challenging hurdles are still being faced. The effects of a better cement quality, of better cementing procedures or of more stringent regulations cannot be easily assessed, through simple and unequivocal criteria; in case of an incident or accident, the *post mortem* analysis is difficult as the origin of the leak is several hundreds or even thousands of metres below ground level. Drawing experience from real life takes time. One possible approach is based upon epidemiological principles, *i.e.*, the statistical analysis of the largest number of cases and identification of correlations.

In a study of data for 315 000 oil, gas and injection wells held by EUB, the regulatory agency in Alberta, Canada, Watson and Bachu (2007) discussed the results of two mandatory tests for wells, which have been required since 1995. The tests, undertaken within 60 days of drilling rig release and prior to well abandonment, are the Surface Casing Vent Flow (SCVF) test, and the Gas Migration (GM) test, which provides at least a first indication of well tightness. The paper focused on abandoned rather than active wells. These results are relative to tests performed at ground level

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and there is a risk, as for any statistical analysis, that the relation between causes and consequences remains ambiguous. Data analysis shows that there is a correlation between SCVF/GM results and oil price (with higher price comes the incentive to drill more wells, or more difficult wells, although equipment and skilled workforce are scarcer), geographic location and technology or regulatory changes. Additional influential factors are wellbore deviation, well type (drilled and abandoned wells have leakage occurrence rates smaller than cased and abandoned wells) abandonment method (wells in which a cement plug was placed across completed intervals has better results than bridge-plugged wells). Low cement top and exposed casings were found to be the most important indicator for SCVF/GM poor results.

Nicot (2009) surveyed abandoned oil and gas wells in the Texas Gulf Coast, drawing a list of factors, which are favourable for long-term tightness. The abandonment year is of special significance, as innovations were progressively introduced: Use of centralizers (1930), caliper surveys (1940), tagging of the cement plug, introduction of improved cement additives adapted to temperature, pressure, and chemical-specific conditions (1940), improvement of the quality of material used in well construction and abandonment. Nicot also outlines the promulgation of both specific plugging instructions by the Texas RailRoad Commission (In 1934, the RRC promulgated specific plugging instructions, and did so again in 1967.) and the Drinking Water Act, publication of API national standards (starting 1953), increased scrutiny by the State (after 1983) and certification of plugging operators (1997). Nicot points out that problems lie in the plugging/abandonment performance rather than in the quality of the material used.

In a survey of new gas wells in the US, Miyazaki (2009) suggested that up to 10% of the wells leaked. More specific to natural gas storages, Marlow (1989) undertook a survey covering some 6953 wells operated by twenty American Gas Association member companies. He mentions that:

> "Tests show that even when the most up-to-date cement types and techniques are used, leakage can and will occur in a significant number of cases" (p. 1151).

The number of wells with a known operation lifetime duration until the leakage was detected was 426 (6%), among which 77% leaked in less than 30 days (it is likely that they were rapidly repaired). Leakages at greater than 10 injection/withdrawal cycles occurred in only 2.6% of cases. The only statistically significant correlating variables are depth and bottom-hole pressure. Wells that leak tend to be deeper (>4500 ft, or 1375 m) and have higher pressures (>3000 psig, or 21 MPa).

In this paper a different approach is adopted. The paper draws on a report prepared by Réveillère *et al.* (2017) for the Solution Mining Institute (SMRI), representing a collaborative effort to gather and explain all wellhead failure, overfilling, or casing leaks incidents in the salt caverns storage industry; provided that public information was available, reliable and precise enough to gain a satisfactory understanding of the event. This analysis builds on 12 cases, whereas the SMRI report detailed 21, in order to focus our analysis on casing leaks incidents (overfilling and wellhead failure are not considered in this paper). Cases which were not considered in the SMRI report imply breaches at the cavern walls, operational problems or surface piping failure. Additionally, two cases in the SMRI report – Conway and Yoder, Kansas – were merged in the present article. Hence the fact that 11 cases are presented, instead of 21 in the SMRI report.

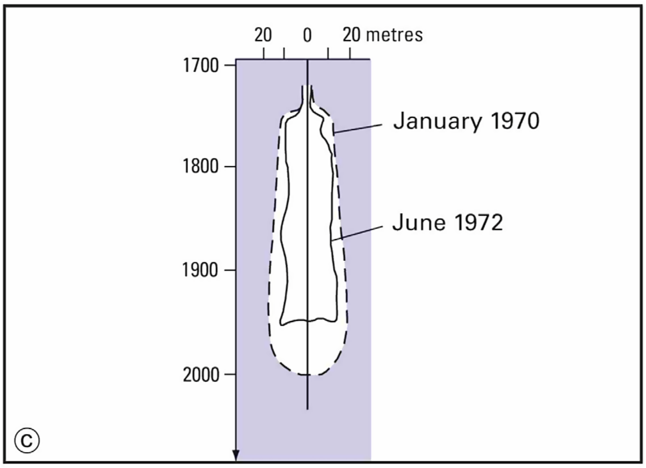

Fig. 1. Extent of salt creep and decrease in cavern size for Eminence Cavern #1, as determined from cavern sonar surveys in 1970 and 1972. Based upon and redrawn from Allen (1972); Baar (1977); Coates *et al.* (1981); Bérest and Brouard (2003).

The twelve cases of loss of tightness in salt caverns due to a leak through or along the cemented casing are described briefly in the first part of this paper. The second part, draws general lessons learned from these cases.

2 Case histories

2.1 Eminence salt dome, Mississippi, 1970, 2004 and 2010–2011

The Eminence salt dome is located 20 km (12 miles) northwest of Hattiesburg, Mississippi. The top of the salt is between 730 and 743 m (2400–2440 ft); it is overlain by a 150-m thick cap-rock of limestone and anhydrite. In 1991, this natural gas storage site comprised seven caverns. Caverns #1–#4 were certificated in the early 1970's and caverns 5, 6 and 7 in 1991. These caverns are especially deep, from 1725 m to 2000 m in the case of Cavern #1 (Fig. 1). For those wells drilled in the 1970s, a 30″ surface casing was set and cemented at 50 ft. A 28″ hole was then drilled to 2700 ft (823 m) and a 20″ OD cemented casing set, and the last cemented casing shoe, diameter 13⅜″, was at 1737 m (5700 ft) depth (Allen, 1971, 1972). Cavern #1 was filled with gas at a 7 MPa (1000 psi) pressure over a period of 2 months, after which it was increased to 28 MPa (or 4000 psi; geostatic stress at cavern depth is 38–45 MPa). After a second pressure cycle, the "*cavity bottom was at 1953 m (6408 ft), showing a loss of 46 m (152 ft) in about* *two years*" (Baar, 1977; Coates *et al.*, 1981) and cavern volume loss was 40% (Fig. 1). Once the problem was recognised, reduced losses were achieved through various measures, including maintaining a higher minimum pressure over extended time periods and less dewatering.

In 2004, Cavern #4 well casing failed at a depth of 1639.5 m (5379 ft; Wellinghoff *et al.*, 2013), *i.e.,* a few dozens of feet above cavern roof. The company took Cavern #4 out of service, filling it with water and shutting it in. On December 26, 2010, a large, unexpected pressure drop of 2.5 MPa (357 psi) in one minute was detected in Cavern #3. The initial response to the leak was to flow ~8.65 mcm (306 MMcf) of gas into the pipeline system. Another gas leak from the wellhead of Cavern #3 was accompanied by water shooting into the air from on-site water wells. On January 4, 2011, the company began flaring gas from Cavern #3, until its production tubing became clogged with debris. Gas was also escaping from the ground around the wellhead of Cavern #1. A large cave-in occurred, sealing off the flow. The company began drilling monitoring wells in the surrounding freshwater zones. By January 24, 2011, the decision was made to take Caverns #1 and #3 out of service. Later, a leak to the caprock was detected in Cavern #7 and maximum operating pressure was lowered from 24.8 MPa to 19.1 MPa (3600 psi–2775 psi).

Investigations revealed that leakage in Cavern #3 well likely arose through salt creep leading to overstretching of the casings above the cavern, where displacements due to creep closure were especially intense (Wellinghoff *et al.*, 2013). These excessive strains led to damage of steel casings and/or steel-cement and cement-rock interfaces, as a result of which, gas migrated up the well to the cap-rock and ultimately to surface.

2.2 Elk City, Oklahoma, 1973

On February 23, 1973, the Oklahoma Geological Survey was informed that a central crater about 10 m by 15 m (30 ft by 50 ft) by 6 m (20 ft) deep, plus 20 m–50 m (160 ft–360 ft) -long pressure cracks radiating from the crater, had appeared in level grassland, about 8 km (5 miles) south of Elk City, Oklahoma. Siltstone blocks of 20–45 kg (50–100 pounds) were thrown as far as 23 m (75 ft) away, and several 30-ton boulders were lifted to an upright position (Fig. 2, left), and 5 m (15 ft) tall trees in the vicinity were tilted 45°. On March 1, 1973, gas samples were taken at the blow-out site. Analyses revealed 1% total hydrocarbons, of which 75% was propane, a result excluding any natural origin. A leak from a propane salt storage cavern leached out from the upper part of the Permian Blaine formation was suspected. Several investigations and tests were undertaken at that site. A 13-hour observation period with the cavern maintained at constant halmostatic pressure was performed (*i.e.,* with the inner tubing filled with saturated brine and opened at the surface). This test found a 30-gal/day (5 L/h) apparent leak in the cavern (such a test is not fully conclusive as phenomena other than a leak can explain such an outflow). The storage cavern was emptied, with the propane being displaced from the cavern by brine on March 28. The two inner strings were retrieved and checked for flaws (Fig. 3). A cement-bond survey was run to assess cementing around the 10-¾″ casing string. The survey demonstrated that the lower 60 m (200 ft), from about 341 m to 411 m (1120 ft–1347 ft), in which a special resin cement had been used, was well bonded and that the upper 341 m (1120 ft) was poorly bonded. This strongly suggested that the leak was between 35.5 m and 340 m, a zone in which the well was equipped with a single cemented casing (instead of two casings above 35.5 m). As illustrated in Figure 3, liquefied gas would have leaked through a weak point in the well casing, migrated upwards in the poorly cemented annulus until it reached the Doxey shales. From there it would have migrated laterally to the blow-out site 700 m away from the wellhead and at 23 m lower elevation. The liquid LPG pressure would have decrease along the migration, triggering LPG vaporization at some point. The mechanical energy liberated by the vaporization generated the crater and cracks observed at the surface.

Both retrieved strings were then run back into the well with a packer added for isolating the 7″ × 10¾″ annulus at 365 m (1197 ft). This annulus was filled with inert water and tested for leaks (Fig. 3). No leak was detected and neither did a pressure test on the cavern prove any leakage. The storage well was returned to service on April 23, 1973. There were no later reported leakages similar to the one that led to the blow-out, suggesting that the breach depth was located above 365 m depth, a zone now covered by two casings and a monitoring annulus.

2.3 Conway-Yoder cavern field (Hutchinson salt formation), Kansas, 1980 and 2000

Over 600 solution-mined salt storage caverns are located in Kansas. Nearly 50% of these are near Conway, a small town in eastern Kansas, where underground storage of Natural Gas Liquids (NGLs) began in 1951. Evidence of fugitive NGLs was known as early as 1956 (Ratigan *et al.*, 2002). Propane was detected in several operators and domestic wells, ultimately leading to the relocation of residents and demolition of the properties.

The Hutchinson Salt Member of the Permian Wellington Formation from which the storage caverns were leached out, is shallow (around 120 m (400 ft); Fig. 3). It is overlain by two impervious shale formations (Ninnescah and Wellington shale formations), above which lies the Quaternary Equus Beds Aquifer, a source of potable water. The eastern boundary of the Hutchinson Salt Member is a dissolution boundary (Fig. 4).

In December 2000, fugitive NGLs were encountered in a recently drilled cathodic protection at the Williams Conway Underground East (CUE) storage facility, which includes 71 caverns. Within a 1.6 km (1-mile) radius of this well, all wells (water, oil, observation) were investigated. NGLs were encountered in two more wells near brine recovery wells. The 71 operating wells were evaluated through pressure monitoring and temperature logs. As of March 15, 2002, nearly all the wells have been evaluated and none have been found to be a contributor to the fugitive NL occurrence. Cement bond logs run in the wells revealed that casing cement-bonds were poor.

Fig. 2. Central crater (left, from Fay, 1973a) and one of the pressure cracks (right, from Fay, 1973b) discovered on February 23, 1973.

A similar incident occurred on June 30, 1980 near Yoder, Kansas, 9.7 km (6 miles) south of Hutchinson and 48 km (30 miles) south of Conway. A propane blow-out occurred along the shoulder of a county road. Bryson (1980) reported:

> "Groundwater and sand were blown fifteen to twenty feet into the air. Within twenty-four hours, the pressure of the propane in hole had abated. Within a week, the surface of the water in the blow-out conduit was placid, however propane vapors continued to rise up through clay and silt surrounding the hole".

In 2004, Johnson and Hoffine presented an update of the Conway investigations:

> "The results of the investigation indicated a plume of NGL located east of the Brine Production Test Well Willems No. 1. Geophysical logging of the Brine Production Test Well Willems No. 1 and adjacent Brine Production Well indicated poor cement bond along the casings. Subsequent abandonment of the Brine Production Well Willems No. 1 and recompletion of the Brine Production Test Well Willems No. 1 have resulted in a rapid and significant decrease in the concentration of NGLs in the adjacent shallow Monitoring Well CUE01-6S".

2.4 Mont Belvieu, Texas, 1980

This accident occurred in 1980 at Barber's Hill, near Mont Belvieu, Texas, where a salt dome is home to 134 solution-mined caverns (and 135 wells) used primarily for Liquefied Petroleum Gas (LPG) storage and distribution and for brine production (Ratigan, 2009).

On September 17, 1980 a pressure drop was recorded at the wellhead of one of the salt caverns containing LPG. On October 3, a spark from an electrical appliance ignited gas (70% ethane, 30% propane) that had accumulated in the foundation of a house in the area, causing an explosion; there were no casualties. The cavern in which the pressure had dropped was emptied and filled with brine. In the days that followed, gas appeared haphazardly around the area, and 50 families had to be evacuated. Holes were drilled into the water table above the salt to find and vent the gas. Investigations proved (Fig. 5) that gas had leaked through a breach in the well casing – which was 22 years old – at caprock depth. Depths to caprock and to salt are 100 m (350 ft) and 300 m (1000 ft, respectively (Bérest and Brouard, 2003; Pirkle, 1986).

2.5 Teutschenthal/Bad Lauchstädt, Germany, 1988

The Teutschenthal/Bad Lauchstädt storage site is located ≅40-km (26 miles) west of Leipzig, central Germany (Fig. 6), Arnold *et al.* (2010). Bedded rock salt (halite) deposits lie at a depth of 500 m–1000 m (1500–3000 ft), with the thickness of the halite increasing to the SE, from less than 50 m to more than 500 m. The overburden comprises 300 m (1000 ft) of argillaceous rocks overlain by a 110 m (360 ft) thickness of an alternating sandstone and mudstone sequence (Fig. 7).

The well Ug Lt 5/71 was drilled and completed in 1971, within which the last cemented 11-3⁄8″ casing shoe was set at 726.4 m (2382 ft) depth, and the intermediate 16-3⁄8″ casing shoe depth at 92.1 m (302 ft) (Fig. 7). The cavern, with a volume of 40 000 m^3, was used to store ethylene. On March 29, 1988, a drop in pressure in the ethylene annulus of cavern Ug Lt 5/71 from 7.5 MPa to 4 MPa was observed. One hour later, the first eruption of an ethylene – water mixture took place 50 m (165 ft) away from the well and was followed by additional eruptions in a North-West direction and 250 m (800 ft) southward, close to the neighboring cavern Ug Lt 6/71 (Fig. 6). Elongated chimneys formed, from ejected debris and partly pulsating ethylene-water fountains, aligned along parallel WNW-ESE

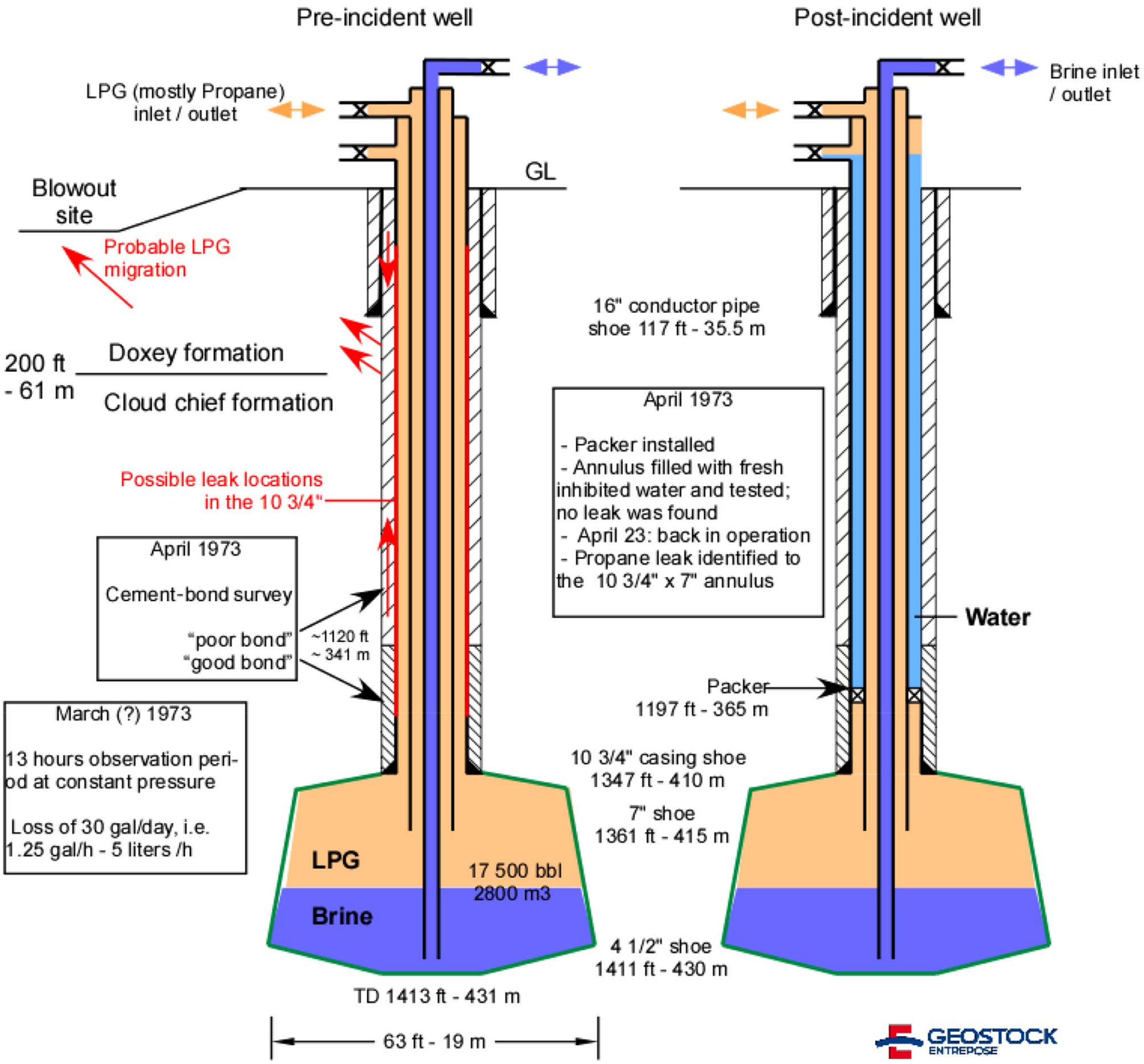

Fig. 3. State of the well before and after the incident, probable leakpath (in red) and summary of the main investigations.

lines. The emission of ethylene continued for several days until an estimated 60–80% of the cavern volume was released. An area of 8 km^2 was evacuated.

Ethylene outflow decreased rapidly. Immediately after the start of the eruption elevation surveys revealed an NW-SE trending ellipsoid uplift of 0.2 m (0.7 ft). Fractures and crevasses, displaced concrete road pads, and fractures were found in a building at the crest of this uplift. This enabled an estimate of uplift prior to the blow-outs as around 0.5 m (1.7 ft).

Subsequent downhole surveys found a damaged connection to the 11-$\frac{3}{4}''$ casing at a depth of 111.8 m, from which ethylene escaped and accumulated in a sandstone layer between 100 and 140 m depth. The sandstone lies below a 25-m thick impervious layer, which was uplifted and led to overstretching and failure of the 11-$\frac{3}{4}''$ casing, ultimately resulting in a massive release of ethylene on March 29th.

2.6 Clute, Texas, 1988

This storage cavern facility was constructed in the Stratton Ridge Salt Dome about 1.6 km (1 mile) NE of Clute in south Brazoria County, 25 km (15 miles) SSW of Houston, Texas. Several hundred oil and gas wells drilled across the salt diapir have established its shape and structure. The caprock is several hundred feet thick, comprising limestones, gypsum and anhydrite beds and the diapir shows an unusual geometry, including a large structural depression in the eastern third of the dome. This and the features and problems associated with the caprock, which are most likely caused by active salt movement, indicate that the internal salt structure is complex and still evolving. The internal structure and fabric of the salt is thus likely to influence construction and operation of any storage caverns (Lord *et al.*, 2006).

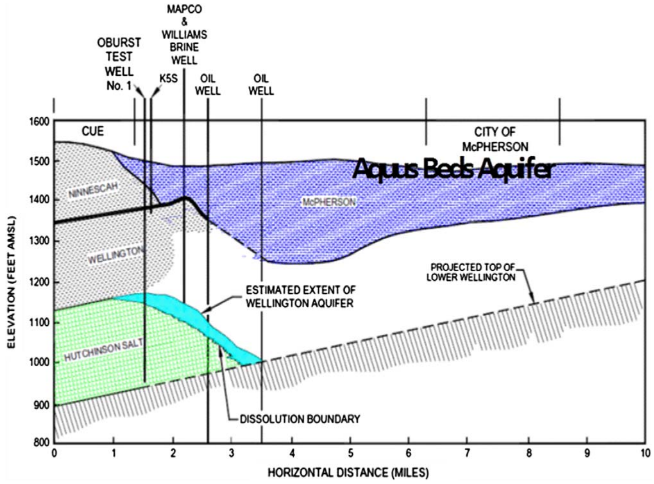

Fig. 4. West-East cross-section of the Williams-CUE Facility (After Ratigan *et al.*, 2002).

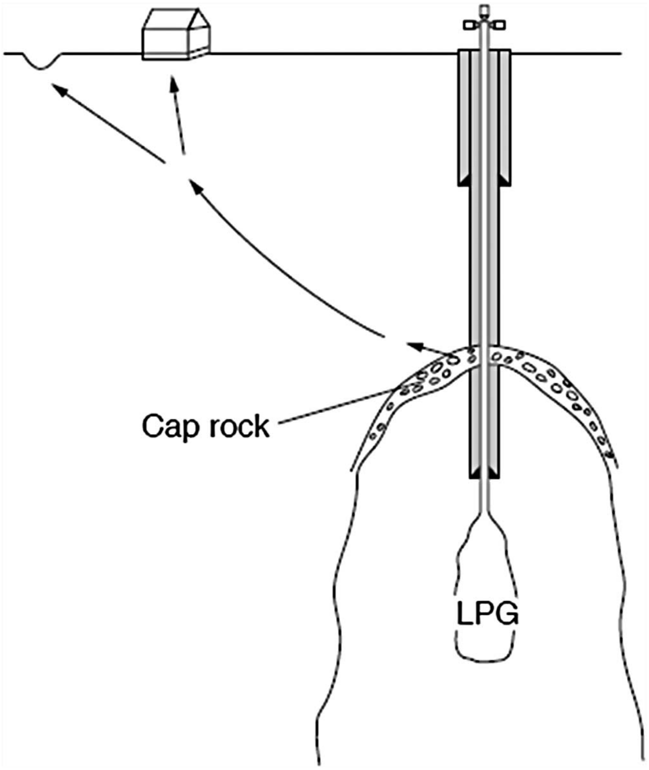

Fig. 5. Conceptual sketch of an LPG leak from the Mont Belvieu cavern (from Bérest and Brouard, 2003).

On December 27, 1988, company officials advised the Rail Road Commission of Texas that they were aware ethylene had been lost from a storage cavern. By December 30, it was assessed that the loss amounted to 1850 m^3 (0.5 million gallons). Water wells in the area were tested but found no contamination (Toth, 1989a). It was decided to drill an exploratory well near the site to try and discover the whereabouts of the escaped ethylene and perhaps attempt recovery of some (Toth, 1989b, 1990). The first test well was drilled on March 19th 1989 and the fugitive ethylene was immediately located. The escaped product was flared off and continued to be so until at least April 1990 (Toth, 1990).

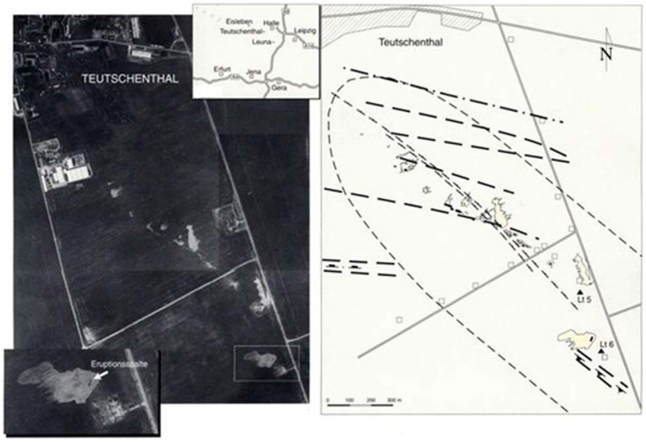

Fig. 6. Aerial photo of the site on April 3rd 1988 showing location of the well, the settlement area of Teutschenthal, alignment of eruptions and close up of main eruption fracture. Right side showing fault zones and area of uplift as dashed lines and elevation measuring points as squares. Based upon and modified from Katzung *et al.* (1996).

Company officials said the casing failure could have been caused by movement in the salt formation with product having escaped at around 396 m (1300 ft) depth.

2.7 Mineola, Texas, 2000

This incident occurred in 2000, at the Mineola Storage Terminal about 145 km (90 miles) east of Dallas, Texas (Warren, 2006). Its cause and how the resultant fire was extinguished was described by Gebhardt *et al.* (2001). The facility had two storage caverns the wells to which were originally drilled as oil producers in the late 1950s. One cavern, the volume of which was 49 000 m^3 (13 million gallons) of propane, suffered loss of product. Well completion included an 8-⅝″ casing set at 484 m (1584 ft). The shoe of the 5-½″ tubing string was 720 m (2400 ft) deep, 30 m (100 ft) above the cavern bottom; it seems that undersaturated water, rather than brine, was used as an injection fluid. The cavern well developed a casing leak at an undetermined depth. According to Gebhardt *et al.*, 2001, the "initial" theory was that injection of undersaturated water led to dissolution and thinning of the salt pillar (wall) between the caverns; a leak was created when a workover was run on the second cavern, where nitrogen was being used in the workover to ensure that there was no LPG in the tubing. The pressure induced in the workover well caused fracturing in the salt pillar. In this theory, the pressure surge was transmitted to the cavern in LPG causing a breach in its well casing. Propane escaped from the well and

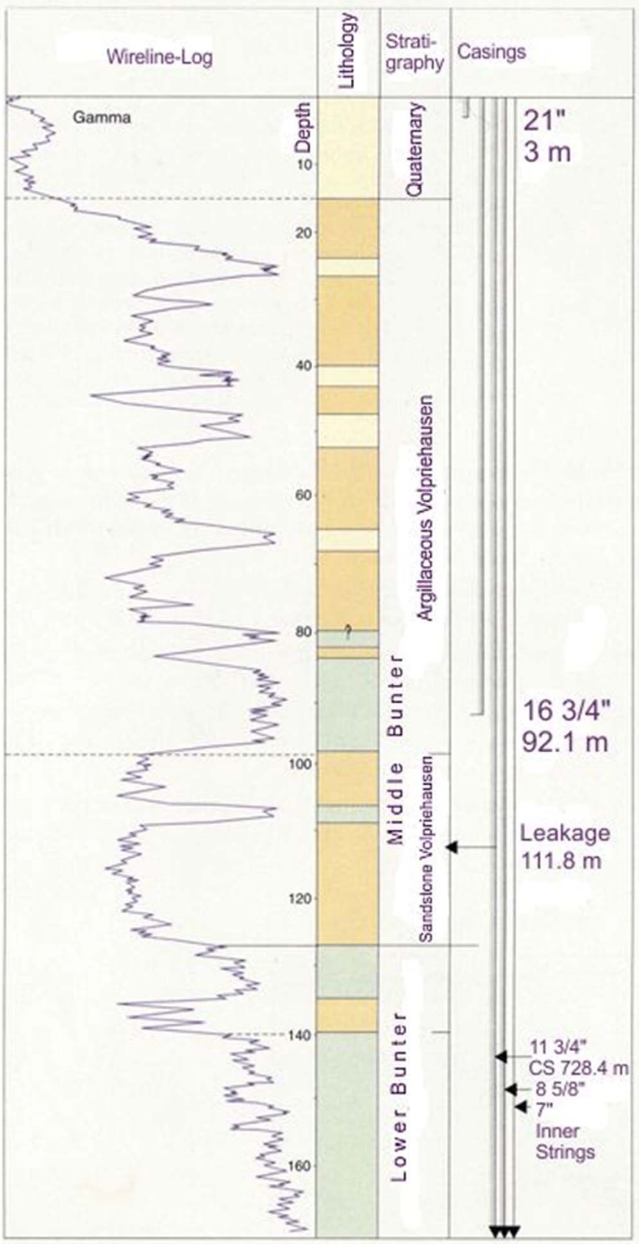

Fig. 7. Casing program and top-hole geology of Ug Lt 5/71. Based upon and modified from Katzung *et al.* (1996).

migrated upwards, eventually escaping through surface soils to the atmosphere. It collected in low-lying areas around the terminal and surrounding forest and found an ignition source. The water-bearing shallow water sand was filled with LPG. A water well used to supply water for cavern leaching located approximately 50 ft (15 m) from the product withdrawal well was first to ignite and burn. This was followed by the cavern wellhead. Propane escaped through the soil up to 30 m (100 ft) from the well itself. Firefighters inferred from the behaviour of the fire that the casing leak was at shallow depth. Considerable efforts were required to extinguish the fire.

2.8 Hutchinson, Kansas, 2001

On January 17, 2001, at 10:45 am, a sudden release of natural gas burst from the ground under a store and a neighboring shop in downtown Hutchinson, a town with 40 000 inhabitants in Kansas. Within minutes, the building was ablaze. During the afternoon of the same day, eight brine and natural-gas geysers began bubbling up, 3–5 km (2–3 miles) east of the downtown fire, some reaching 10-m (30-ft) in height, two of the geysers igniting. The next day, natural gas coming up from such a long-forgotten brine well exploded beneath a mobile home, killing two people.

Also on January 17, 15 min after the first downtown blast and 13 km (8 miles) northwest of downtown Hutchinson, technicians from the Yaggy natural-gas storage recorded a gas-pressure drop of 0.7 MPa (100 psi) in the S-1 salt cavern, whose casing shoe was 239 m (794 ft) below ground level. The underground storage facility was developed in the 1980s to hold propane. The owner became bankrupt, and the wells were plugged by partially filling them with cement. In the early 1990s the site was converted to a natural-gas storage. A link between the pressure drop and the events in Hutchinson was suspected immediately, even though the distance between the storage and the downtown geysers [10–12 km (7–8 miles)] set a puzzling geological and reservoir engineering problem. A plug was set at the bottom of the S-1 well and a downhole video run. This revealed a large curved slice in the casing at a depth of about 180 m (585 ft). It was suspected that various metal objects, including a steel casing coupler, had been dropped down the well when the former storage was abandoned. During the well re-opening, when the cement and cast-iron plugs were drilled, the system composed of the drill bit and dropped metal objects cut a slice "like a kitchen knife cutting into a can" in the 9″ (23-cm) casing of the S-1 cavern at about the depth [179 m (595 ft)] of the later leak. Gas moved vertically up the outside of the casing from the breach until it reached a fractured gypsiferous/dolomitic horizon (G on Fig. 8) at the top of the Wellington Shale Formation. At this point the gas migrated laterally updip to the east towards Hutchinson, remaining trapped between two impermeable shale layers, where it encountered the abandoned brine wells. Most of these were only cased down to a shallow aquifer. Clear evidence of the existence of multiple independent channels within the dolomite layer is suggested by the occurrence of a dozen geysers during the 24-h period following the first blow-out. The geysers appeared in the west and then progressively eastwards, and vented the accumulation of gas under the city, until no further gas eruptions occurred. In the following weeks, a number of seismic reflection lines were acquired to try to locate the gas migration path, and 36 venting wells were drilled. Only eight of them hit gas, supporting the view that migration of gas to surface occurred along narrow pathways or channels within the dolomite layer (Allison, 2001).

After 1997, the State had authorized a 17.5% maximum pressure increase, raising the maximum pressure at the casing shoe (239 m to 794 ft deep) to 4.78 MPa (693 psi). This additional storage capacity remained largely unused for years on Cavern S1. Early in January 2001, gas was

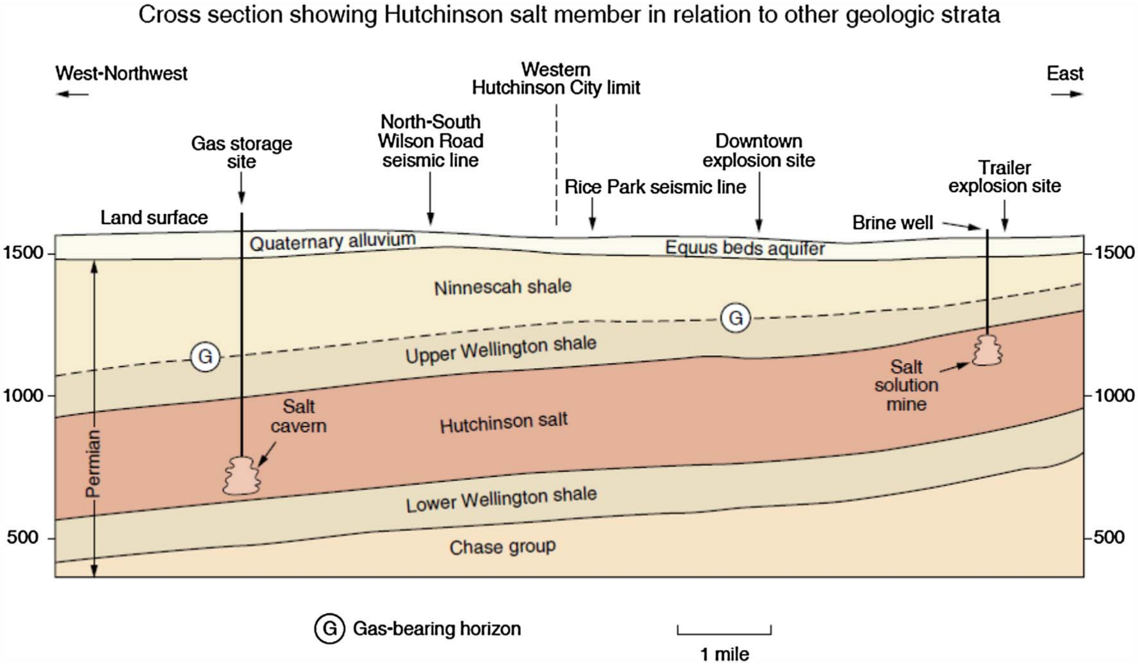

Fig. 8. Hutchinson leak pathway. Quaternary alluvions are composed of sands and gravels, 50-ft thick. Elevations are in feet. Below are the Permian Ninnescah Shale, the Upper Wellington Shale and the Hutchinson Salt member. The gas-bearing interval ranges from 270-ft deep in the east side of the city to 400-ft deep several miles northwest of the city; the dip is 20 ft per mile. Gas migrated through fractured dolomite layers (G-G). (Kansas Geological Survey Web Site, 2001).

injected and the pressure jumped from 2.9 MPa (426 psi) to 4.76 MPa (691 psi) at 6 a.m. on January 14. The pressure gradient was then 2.66×10^{-2} MPa/m (1.18 psi/ft) at leak depth on January 14 and gas pressure was above the overburden pressure. The pressure began to drop at the wellhead, a move that, with hindsight, may be interpreted as a clear sign of increasing leak rate. The pressure build-up spread throughout the gas-filled fractured channels, ultimately reaching that of hydrostatic pressure beneath the Hutchinson area.

After the accident, poor regulation and, when compared to other states, the small number of inspection staff in Kansas state, were implicated by several experts (*e.g.,* Ratigan, 2001). New sets of regulations were discussed and imposed (Johnson, 2002). These included mandatory double casing in wells, corrosion control, restrictions on well-conversion (salt caverns designed to store LPG could not be converted to store natural gas, and cavern wells that have been plugged cannot be reopened and reused), a maximum pressure gradient of 0.76 psi/ft (1.73×10^{-2} MPa/m) at the production casing shoe, and new testing requirements (with a Mechanical Integrity Test (MIT) performed every 5 years).

2.9 Magnolia, Louisiana, 2003

The natural gas storage facility of Magnolia is located at Grand Bayou, Louisiana, where several other storage and brine production caverns are operational. Salt roof is 200 m (600 ft) deep. In 2003, the facility included Caverns #13 and #14, drilled in the 1970's. On November 1, operations started filling the caverns with natural gas. On December 24, an underground gas leak led to the release of about 9.9 MNm^3 (0.35 billions ft^3) in a matter of hours. The gas migrated to an adjacent aquifer and then to the atmosphere. On December 29, cavern operations were suspended and 30 residents were evacuated. The wells were plugged and 36 vent wells were installed in the aquifer over the salt dome, of which 17 collected or burned off gas. Downhole videos were run in the wells. Several theories were put forward to explain the gas leak from around 440 m (1450 ft) below the surface. Causes of the leak were considered to be: crushed casings (EIA, 2006), cracks in the casing (Edgar, 2005; Hopper, 2004), separation of three or four 13-3⁄8″ casings connections permitting gas to leak behind the casing and then to the surface (Nations, 2005), or improper back-welding that resulted in cracks in the well casing (State of Louisiana, 2007). Video of Well #13 is reported as showing cracks in the casing near a coupling; the well had been plugged at the point of the lowest crack, after which the leakage stopped, which pointed to the cracks as a possible cause of the leaks.

2.10 Boling, Texas, 2005

Four caverns had been solution-mined and filled with natural gas between 1980 and 1983 in the Boling Dome near Boling, Wharton County, Texas. Depth to the caprock is globally about 192 m (630 ft), and the top of the salt occurs at a depth of around 305 m (1000 ft). Cavern roof depths are between 1066 and 1083 m (3497 and 3553 ft), except for Cavern #3, the roof of which is deeper by 45–60 m (150–200 ft). Apart from Cavern #3, 11-3⁄8″ casing shoe is close to the cavern roofs (0–18 m [0–59 ft] above), which are flat (Fig. 9).

In the Fall of 2005, Cavern #4 was nearly full. An abnormally fast pressure drop was observed, which was monitored over a period of several weeks. Temperature loggings found cold spots in Caverns #1, #2 and #4, raising the possibility of a production casing leak not far above the cavern roof. During gas removal, the three caverns were filled with water.

Detailed investigations into the incident were undertaken, including running downhole video camera logs, which identified casing collar and coupling partings for over 100 m above the casing shoe depth (Fig. 10). The video log revealed that the casing had failed at eight different locations, always near or at a connection. Failure often was a circumferential fracture. The casing being dragged down after it fractured, up to 60 cm height of cement could be observed in between the two parts of the fractured casing.

Fracture shape, the absence of any failure in Cavern #3 the chimney which was 60-m in height, and flat roofs, strongly suggest that casings were overstretched above cavern roofs and experienced tensile failure. This was confirmed by numerical analyses, that clearly showed the cemented casings of Wells #1, #2 and #4 were not able to accommodate the resulting large tensile salt strains, and their ultimate strength limit was exceeded (Fig. 11).

The well repair procedure for the three leaking wells included milling a 30 m (100 ft) section from the original 11-3/8″ casing and cementing a 10-3/4″ welded liner. The new casing shoe, 30 m higher than the original one, was therefore in a zone where simulations suggest the strain induced by the salt creep should stay below the casings strength, thanks to this new 30 m long cavern neck.

2.11 Epe, Germany, 2014

At the Epe site, 80 km (5 miles) north of Dortmund, Germany, several dozens of salt caverns have been leached-out from a 200–400 m (656–1312 ft) thick sequence of halites overlain by clastic and argillaceous rocks; top of salt can be found at a 1000-m (3281 ft) depth. The Epe S5 cavern is 147 m (482 ft) in height, with a diameter of 82 m (269 ft) and volume of approximately 450 000 m^3 (2.7 mbbls). In 1980, approximately 408 000 m^3 (2.45 mbbls) of oil were injected into storage. The cavern operated in brine-compensated mode, with brine injected or produced through a 7-5/8″ string to displace the crude oil through the 11-3/4″ × 7-5/8″ annulus. The last 11-3/4″ casing is anchored at a 1086.8 m (3566 ft) depth and the penultimate 16″ cemented casing at a 212 m (696 ft) depth. Typical of a strategic oil reserve, it experienced only a small number of withdrawals or injections.

On February 23rd and 24th 2014, a pressure drop of 0.36 MPa (52 psi) was recorded in the annular space of Cavern S5. The cavern was taken out of operation and a number of inspection runs were performed in the well. These did not indicate any evidence of a leakage. The mining authorities agreed to commence operation again on April 2nd 2014 with restrictions regarding the maximum pressure.

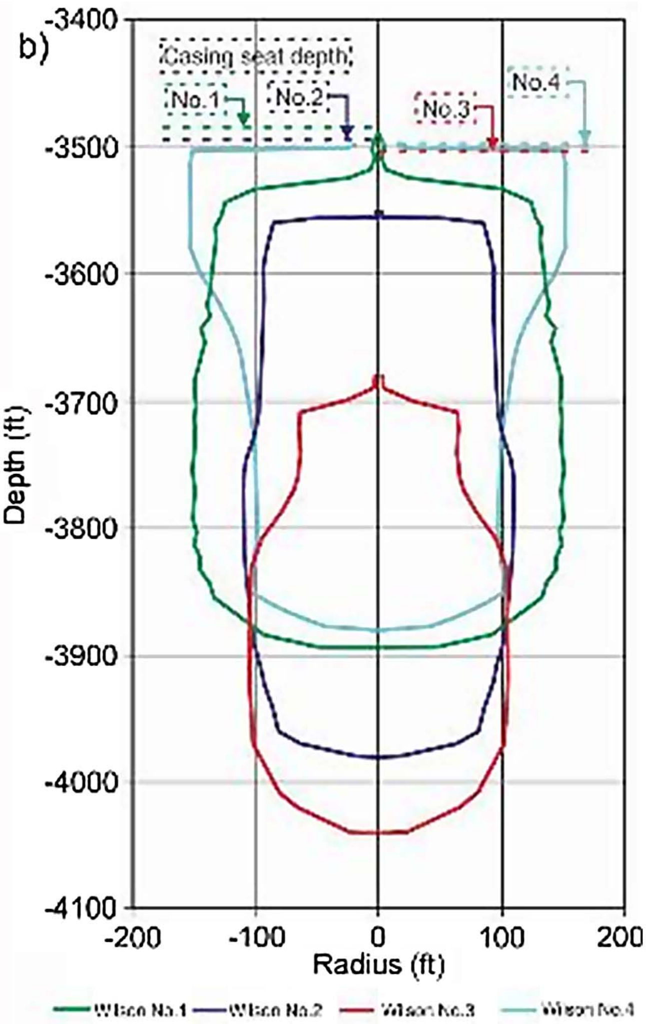

Fig. 9. General cross-sections of caverns, based on sonar data. From Osnes *et al.* (2007)

On April 12th 2014, an oil seep was discovered at surface in a meadow. On April 15th, two more spills developed close to a farm, inducing a family to leave their home for some days. After first analysis of the locations of the spills, it became clear that the origin of the crude oil was Cavern S5. The cavern was made safe and multiple efforts were undertaken to understand the reasons for the leakage, assess the extent of the leakage, minimize its impact and, ultimately, restore cavern integrity.

Investigations and computations suggested that cavern convergence, evidenced by subsidence measurements at ground level, caused movement of the rock mass (salt) surrounding Cavern S5, especially at a depth of 217 m (712 ft; Fig. 12). The calculated vertical strain at a depth of 200 m (656 ft) is approx. 0.1–0.2 mm/m, enough to trigger a significant displacement on the casing connection at 217 m (712 ft). Above 212 m (~696 ft), the completion, including the 16″ casing, is much stiffer and stronger than the one-casing section below and it was concluded that the first casing connection below the 16″ casing shoe was a critical point for structural damage.

Fig. 10. Examples of failures detected by the video inspection. From left to right: Circumferential fracture of the pipe body, of the threaded coupling, and thread jump-out. From Osnes *et al.* (2007).

At a depth of 217 m (712 ft), crude oil pressure was 8.1 MPa and capillary entrance pressure of the enclosing argillaceous series (mudstones) was approximately 4.7 MPa (682 psi). Pre-existing shear zones and fractures in the surrounding rocks re-opened, along which the crude oil migrated as the permeability of the matrix is too low for oil penetration. Upon reaching the base of the Quaternary series, the crude oil migrated into a shallow, groundwater aquifer and ultimately reached the surface.

As a result of this incident, and as is already the case in the Netherlands, it is expected that to prevent that kind of incident in future, the regulations for operating storage caverns in Germany will require a double barrier installation for all wells (Bezirksregierung Arnsberg, 2014; Coldewey and Wesche, 2015; Kukla and Urai, 2015).

3 Analysis

3.1 Leaks main characteristics

3.2 Lessons drawn from incidents

Tables 1–3 provide the main characteristics of 11 incidents, which can be described as leaks through the casing. We do not claim the list is comprehensive. The original work relied on material in the public domain and it is likely that other cases and incidents exist but are not in the public domain. These, it is thought, would include defects in cementation, defective welding or screwing which were detected early (during tests performed after drilling or after solution-mining was completed) and repaired; or the migration of fluids through the cemented annulus, which were collected at ground level and treated. Such incidents, which are part of routine operation and creation of a cavern, are not widely reported in the literature. The table is, however, likely to cover the most significant incidents in the history of storage salt caverns worldwide (except for ex-USSR, for which public information is scarce).

The featured incidents (casing leaks) are relatively few, when it is borne in mind that more than 2000 salt storage caverns have been operated successfully and without incident, sometimes for more than 50 years. Two casualties have arisen (at Hutchinson) and several hundred people have been evacuated during incidents. These are too many, however, the numbers are extremely small when compared to the toll resulting from above-ground tanks accidents that would be the alternative storage option for liquids and gas (Evans, 2007). From the perspective of safety, underground storage benefits from several intrinsic advantages (no oxygen is available underground; high fluid pressures are the normal state underground, sensitivity to terrorist activities or other acts of aggression is low).

However, lessons must, and can be, drawn to prevent further accidents.

4 Factors influencing the occurrence of a casing leak

The analysis of the leak mechanisms identified in the 11 cases previously analyzed enables to identify some common patterns. In the following the onset and nature of a breach (Sect. 4.1), the development of a leak (Sect. 4.2), consequences at ground level and monitoring-prevention are discussed (Sect. 4.3). These three successive steps are represented in Figure 13.

4.1 Onset of a breach

4.1.1 Leak initiation

In most incidents, a breach (and leakage) is created through a steel casing at a depth where the well completion comprises a single cemented casing (“single barrier”). It is noteworthy that in the oldest wells, the depth of the penultimate casing shoe was shallow, and a single casing formed more than 50% of the total length. In the accidents described here, depths of the two last cemented casings were 35.5 m and 410 m at Mineola; 212 m and 1086.6 m at Epe; 823 m and 1737 m at Eminence; 92.1 m and 728.4 m at Teutschenthal (Fig. 14).

The breach may result from physico-chemical phenomena (internal and external corrosion), or in faulty screwed or welded connection between two consecutive pipes. However, external mechanical phenomena may also contribute to the creation of a breach. At Hutchinson, a somewhat exceptional case, an LPG storage well on abandonment was plugged and cemented. When required for later natural gas storage, the well had been drilled-out. A slice was cut in the steel casing during drilling.

Deformation of the salt mass (or, more generally, the rock formation) is a more generic cause. Two basic cases

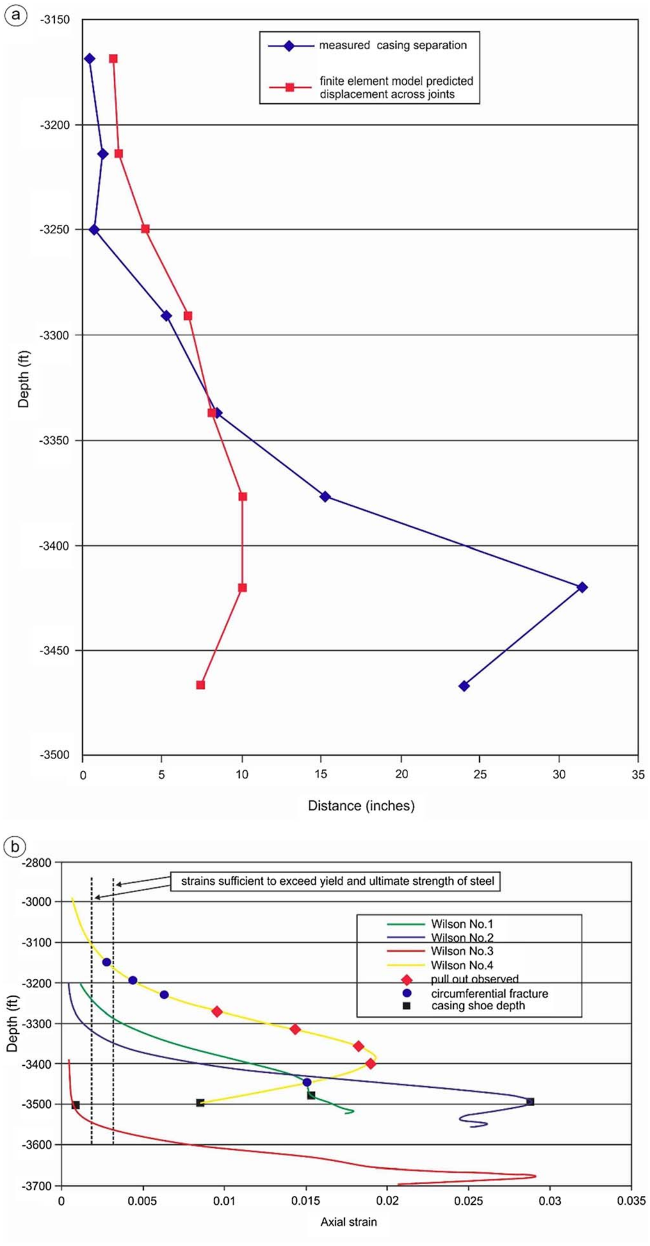

Fig. 11. Observed and modelled casing deformations (from Osnes *et al.*, 2007). a) Comparison of measured casing separation and predicted relative displacements between casing connections from finite element modelling; b) vertical strains as a function of depth in the salt near the centre lines of the Wilson storage caverns predicted from finite element modelling.

can be distinguished, depending on whether the casing is subject to excessive tensile or shear stresses.

In the first case, the last cemented casing shoe is close to the cavern roof (the "chimney" or "neck" below the casing shoe is not very tall). In the case of Eminence, cavern creep closure was rapid in this region of the well, because the caverns were deep, and/or because cavern roof was flat, a shape that generates large vertical strains, as in the case of Boling wells #1, 2 and 4. In Boling well #3 the last casing shoe was anchored much higher above the cavern roof and the well experienced no leak (Fig. 9). In both the Eminence and Boling cases, large vertical strains led to casing overstretching and failure.

To a certain extent, the Epe case also belongs to the tensile failure type, however overstretching took place at much shallower depth. Breach creation is believed to originate in a large overall subsidence, which was initiated by and as a result of cavern convergence. This led to a sharp contrast in vertical deformations above and below the penultimate casing shoe, where the breach appeared. At Teutschenthal, two stages were recognised in the leak development. The initial leak rate was slow, perhaps over many years, or even dozens of years, during which time gas accumulated in a 30-m thick layer whose thickness increased by half a metre; in this layer the casing, strongly bonded to the rock mass, became overstretched and at one point it experienced tensile failure, leading to the formation of a much larger "secondary" breach, which allowed higher leak rates. One hour later, ethylence and water mix blew out at ground surface.

In the second case, due to tectonic deformation inside a salt dome, large differential movements develop, including horizontal differential (shear) displacements between two levels, the mechanical properties to which are in sharp contrast (for instance, salt top and caprock). The casing, which is strongly bonded to each of these two levels, experiences shear failure (this is likely to have happened at Clute). This interpretation is confirmed by several incidents (the consequences of which were small) such as the failure of casings at caprock depth at the West-Hackberry oil storage facility (Sobolik and Ehgartner, 2012).

There is no well-documented example in which a leak clearly starts at the depth of the last-cemented casing shoe, which often is considered to be a weak point from the perspective of cavern tightness. For instance, at Boling, breach(es) were close to, but above the casing shoe point.

To summarize the main findings, two likely causes – which do not exclude one another, and do not exclude a combination with other causes – appear. In all the cases, a breach is created in a zone where well completion includes a single casing. Except for the Hutchinson case (the breach was created when re-drilling an abandoned well), five cases are related to a structural cause: Eminence, Boling, Clute, Teutschenthal and Epe cases, with proven or suspected excess tensile stress experienced by the casings. In the Eminence, Boling, Clute and Epe cases, this is, or is suspected to be, due to salt creep dragging down the casings. In the Teutschenthal escape, this was due to a small leak that accumulated over a caprock, creating a local uplift. We note that phenomena are relatively slow to occur and if a tightness test had been conducted during commissioning of the caverns, it would not have detected a problem. Therefore, a relationship exists with the ages of the wells.

4.1.2 Influence of well age

Table 4 illustrates that leakage occurrences happen several dozens of years after well creation. This might be the time needed for a breach in the casing to occur through corrosion; or excessive strains, tensile and shear stresses to build

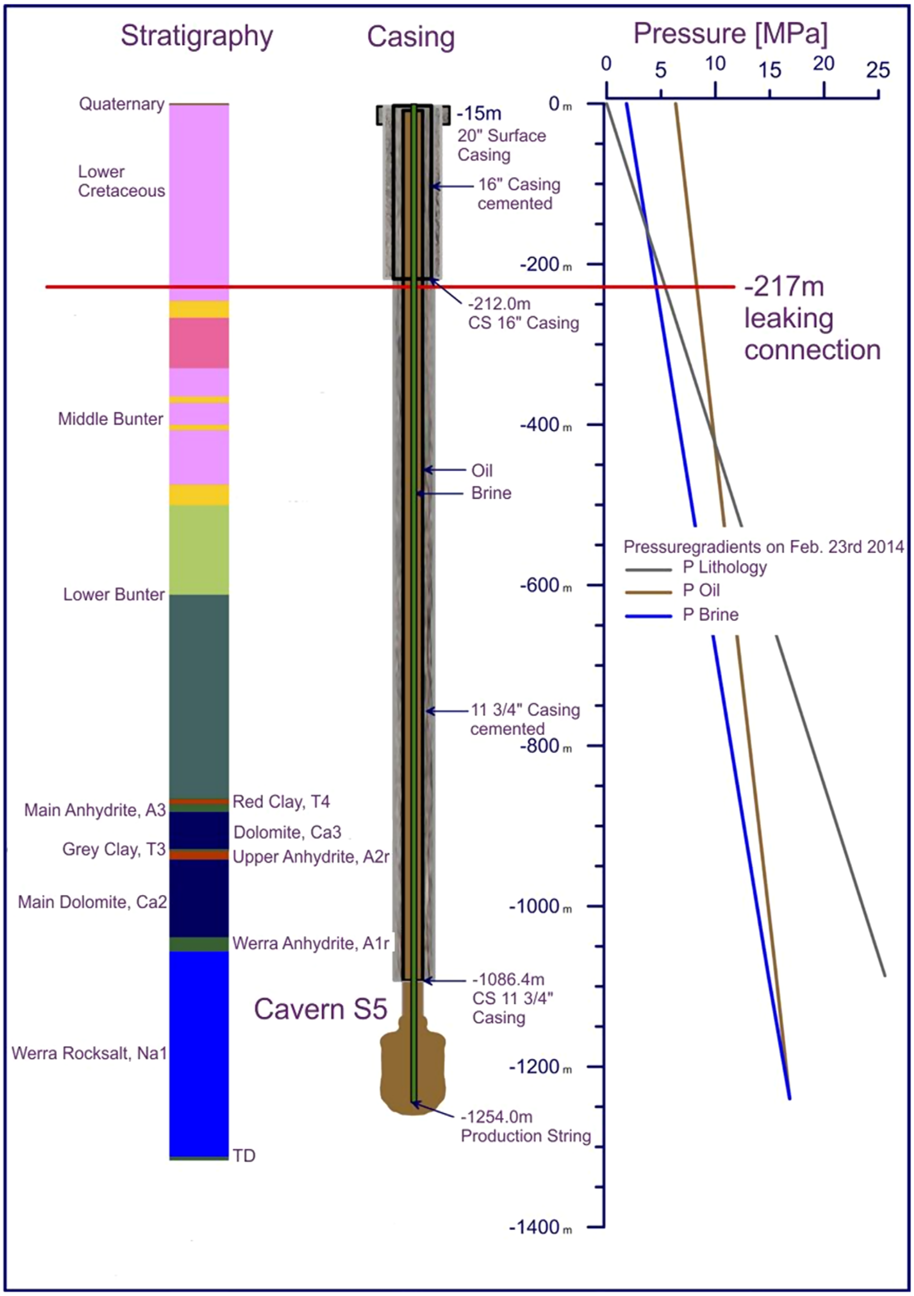

Fig. 12. Well scheme and pressure gradients of Epe S5 (Stöwer, in: Réveillère *et al.*, 2017)

up through salt creep. In the US, the last incident occurred in Texas in 2005 (where, since 1993, a double casing anchored in the salt formation has been mandatory for new caverns) at Boling, which had only one casing anchored in the salt formation, and in 2001 in Kansas (where similar regulations were enforced in 2003 following the Hutchinson incident).

4.2 Leak development

In this section the factors which favour the development of a leak are explored.

4.2.1 *An intermediate outlet often is needed*

A leak can only develop from a breach in the casing when a pathway to an outlet exists, or is created. This outlet may be ground level, a sufficiently porous and permeable underground layer or structural zone (*e.g.*, a fault or jointed rock mass). Conversely, where no receptor horizon exists, or when the cementing job was completely successful, leading to a low permeability and a high gas entry pressure, a breach in the casing does not result in a leak. This occurs when, at breach depth, the rock mass is tight or deforms plastically, tightening the bond between rock and the cement job. In this respect, rocksalt (or clays/shales)

Table 1. The main characteristics of Elk City, Oklahoma; Conway-Yoder field, Kansas; Mt Belvieu, Texas; Mineola, Texas.

		Elk City, Oklahoma	Conway-Yoder field, Kansas	Mt Belvieu, Texas	Mineola, Texas
Cavern information	Commissioning	After 1954	600 caverns since 1951	1963	End of 50's
	Incident date (1st noticed)	February 1973	NGL detected in wells 1956–2012; Propane atmosphere eruptions June 30, 1980	9/17/1980 (pressure drop); gas burst on 10/3/1980	1995
	Geology	Bedded salt Formation Blaine, alternating layers of salt, anhydrite, shale's	Bedded salt tight overburden; located at a dissolution boundary	Domal salt Pervious Caprock Drill losses	Domal salt
	Stored product	LPG (mainly propane)	Propane, or LPG	Ethane, propane	Propane
	Last cemented casing shoe	10¾″ at 410 m	≈200 m		8⅝ at 482 m
	Penultimate cemented c.s.	35.5 m			
Leak mechanism	Breach depth	Less than 365 m deep			Shallow?
	Pressure drop			On 09/17/80	
	Mechanism	A breach somewhere between 365 m and 35.5 m, upward in the cement, horizontal in the Doxey Formation	Gas leaking from several faulty wells	The leak was likely to be at caprock depth	A breach in the casing originating from a pressure surge in a neighboring cavern
Impact at the surface	Effects at ground level	9 × 15 m, 6 m deep crater	Propane found in shallow wells	Explosion in a cellar, gas is found in shallow waters	Gas occurrences near the wellhead
	Distance from wellhead	700 m, 23 m below wellhead elevation			In a 30-m radius around the wellhead
	Evacuation/ Casualties		Several families relocated	50 families evacuated	
Emergency resp. and remediation	Measures taken	Soil gas sampling and analysis, storage emptied, CBL run	Analysis of geological data, Temperature logs, CBL, 8 monitoring wells drilled, 71 operating wells evaluated	Cavern emptied, wellbores tapped in the shallow aquifer layer to vent gas	Fire extinguished
	Remediation	Water-filled annular space, packer set at 365 m	Brine wells abandoned		

Table 2. The main characteristics of Hutchinson, Kansas; Epe, Germany; Magnolia, Louisiana.

		Hutchinson, Kansas	Epe, Germany	Magnolia, Louisiana
Cavern information	Commissioning	Drilled in the 80's, and abandoned. Re-opened and filled with natural gas in the 90's	1980 (Epe S5)	Wells 13–14 drilled in the 70's
	Incident date (1st noticed)	January 19, 2001	Feb 23, 2014	Dec 24, 2003
	Geology	Bedded salt, Overlain by impermeable layers; however, thin subhorizontal fractured layers between two shale layers	Bedded salt, Zechstein (Z1), 200–400 m salt layer, roof at 1000 m, overlain by clastic and argillaceous layers	Domal salt (Napoleonville dome), salt roof at 200 m (?)
	Stored product	Natural gas	Oil	Natural gas
	Last cemented casing shoe	9″ at 238 m	11-3⁄4″ at 1086.8 m	13-3⁄8″
	Penultimate cemented c.s.		16″ at 212 m	
Leak mechanism	Breach depth	180 m	≈ 217 m	≈440 m
	Pressure drop	yes	0.36 MPa	
	Mechanism	Milling created a breach when re-drilling a cemented abandoned well. Gas migration through fractured channels to the brine aquifer below Hutchinson, and to ground levels through very old and poorly abandoned brine wells.	Casing overstretching due to caverns convergence	A flaw in the casing at a 440-m depth, attributed to poor welding job.
Impact at the surface	Effects at ground level	A dozen geysers, gas + brine,	Oil seeps after April 12, 2014	During first filling, 10^7 m^3 of gas migrate to an aquifer layer, then to ground level
	Distance from wellhead	13 km	200 m	
	Evacuation/Casualties	Two casualties	10 cows put down; one family displaced for some days	30 residents evacuated
Emergency resp. & remediation	Measures taken	Bottom plug set on January 24. A video detects the breach. 36 shallow boreholes are drilled, eight of them find gas. A seismic reflection survey is undertaken,	Wellhead checks, CBL, sonar survey, measures taken for water protection, video, monitoring wells	A bottom plug is set. 36 boreholes drilled to the aquifer layer, 17 find gas. Video.
	Remediation	Rules rescinded	An internal string is set	Caverns filled with brine

Table 3. The main characteristics of Eminence, Mississipi; Teutschenthal, Germany; Boling, Texas; Clute, Texas.

		Eminence, Mississipi	Teutschenthal, Germany	Boling, Texas	Clute, Texas
Cavern information	Commissioning	1970–1973. Caverns #1–#4	1971	1983. Caverns #1, #2, #4	Leached out in 1961
	Inccident date (1st noticed)	December 26, 2010	March 29, 1988	December 24, 2003	December 1988
	Geology	Domal salt (Eminence dome), 150-m thick caprock, whose roof is at 600 m.	Bedded salt. Top of salt from 500 to 1000 m, overlaid by a 300 m thick clay layer and 110 m of clay/sand layers.	Domal salt (Boling dome), Caprock at 190 m and above, salt roof at 300 m	Domal salt (Stratton Ridge dome), 100-m thick caprock, limestone, gypsum, anhydrite. The dome is likely to be active.
	Stored product	Natural gas	Ethylene	Natural gas	Ethylene
	Last cemented casing shoe	13-3⁄8 at 1737 m	11-3⁄4″ at 728.4 m	1066–1083 m. Very close to cavern roof for #1, #2, #4.	
	Penultimate cemented c.s.	20″ at 823 m	16 3⁄4″ at 92,1 m		
Leak mechanism	Breach depth		Connection at 111.8 m?	Eight seen from video logs between 3100 and 3400 ft	
	Pressure drop	2.46 MPa in 1 min on #3	From 7.5 MPa to 4 MPa	Rapid pressure drop over several weeks	
	Mechanism	Likely factors: Fast cavern closure rate (40% in one year) frequent re-brining,	Ethylene accumulated in a 100–140-m deep layer overlain by a poorly permeable, 25-m thick layer. Layer uplift led to overstretch of the 11-3⁄4″ casing, which breaks on March 29, followed by a massive leak. Ethylene leakage paths are along existing faults.	Casing overstretch and failure, dragged down by the salt. This was facilitated by the flat roofs and the absence of cavern necks.	Effects of dome internal movements?

Continued on next page

Table 3. (Continued).

		Eminence, Mississipi	Teutschenthal, Germany	Boling, Texas	Clute, Texas
Impact at the surface	Effects at ground level	Blow-outs in shallow boreholes	One hour after the pressure drop, first ethylene + water blow-out, followed by several others, gas production during several days, 60% to 80% of cavern volume is lost. Blow-out spots aligned on parallel lines. Ground uplift by 1.5 m before the eruption. Fractures at ground level.	None	None. Gas loss estimated to be 27 000 m^3 on December 30.
	Distance from wellhead	The leak escaped from the ground around #1 wellhead	50 m–250 m		
	Evacuation/ Casualties	Twenty families during two weeks	An 8 km^2 zone		
Emergency resp. and remediation	Measures taken	Partial venting 245 shallow boreholes drilled 13 boreholes drilled to the caprock	Ethylene dilution was swift. Alignment of blow-out spots was checked through aerial photos.	Cold spots detected above the casing shoe by temperature logs. Video inspection.	After discussion with the mining authorities, a new borehole was drilled, encountering gas on March 19, 1990. Gas was vented.
	Remediation	The four caverns are abandoned	An 8-⅝″ string is set in the casing and the annular space is monitored.	Milling of the 11-¾″ casing on a 30-m length, a 10-¾″ string is set in the casing.	Unknown

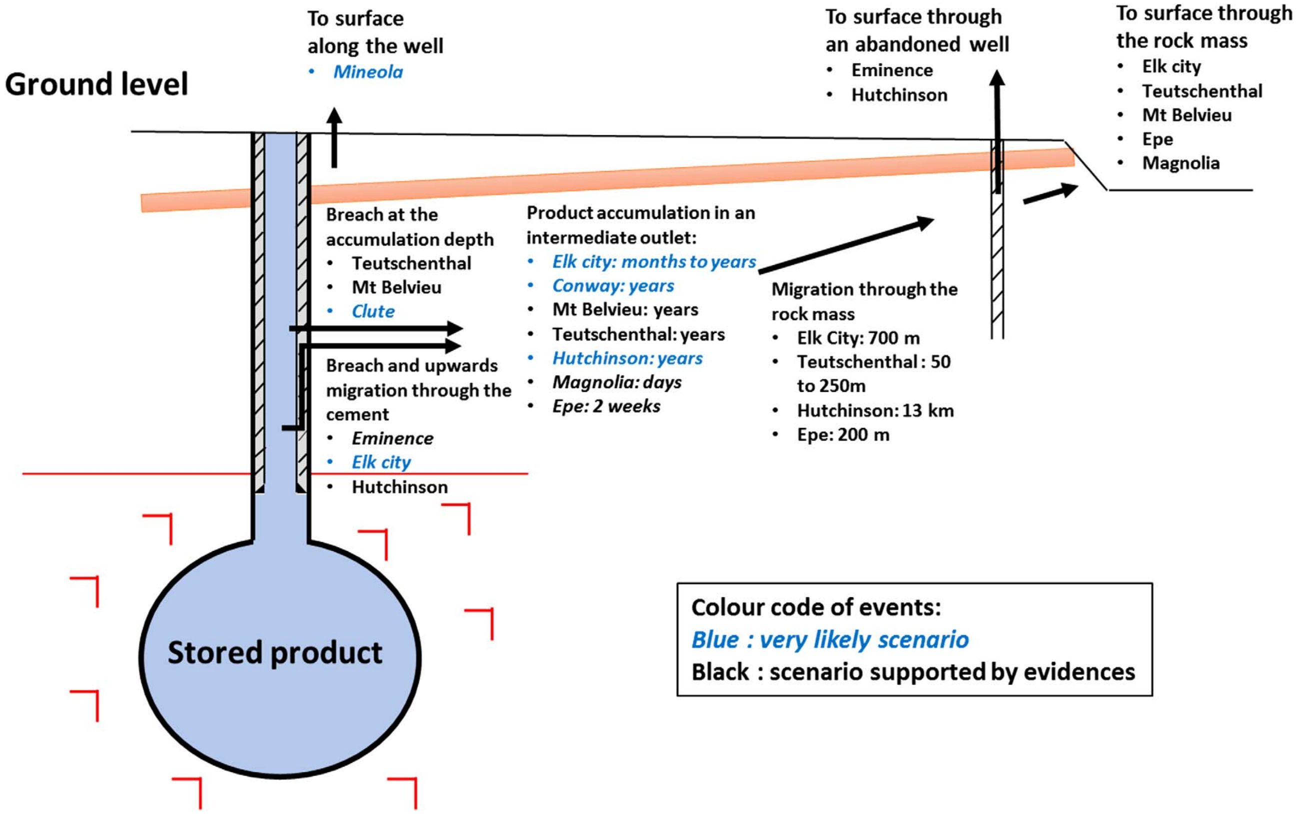

Fig. 13. Schematic of leakage development cases with an intermediate outlet accumulation.

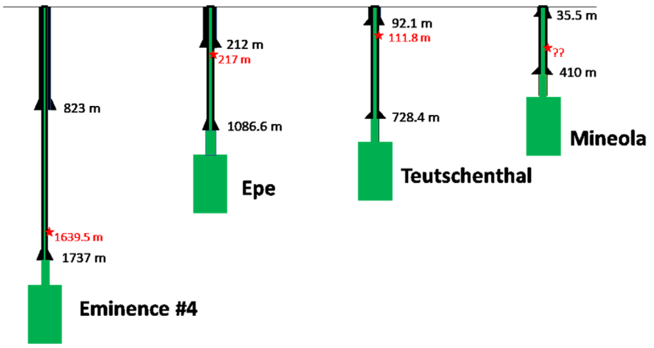

Fig. 14. Depths of the two last cemented casings and depth of the breach through the tubing at Eminence, Epe, Teutschenthal and Mineola.

exhibits very favourable properties; however, it does not mean that no fluid can migrate at the rocksalt-cement-steel interfaces, as witnessed in the Eminence or Boling examples. We also note here that cases exist in both the storage industry and in oil and gas production wells, where a leak built up in the cemented annulus.

Generally speaking, however, in spite of many advances (see Sect. 1), it is difficult to guarantee cementation quality from wellhead to the last cemented casing shoe.

In many cases, the leak finds an underground receptor, *i.e.*, a porous and permeable zone whose volume is large enough to accommodate, at least for a period of time, a large quantity of fugitive hydrocarbons. This outlet can be at the same depth as the breach, for instance in the dome caprock (Mont Belvieu, and probably Clute also) or, as in Teutschenthal, in a sandstone layer, 30 m thick, below a tight overburden layer.

However, in many other cases, receptor depth, where leaking products accumulate, is shallower than the breach depth itself. When the enclosing rock is tight and well cementation is poor, hydrocarbons can migrate upward in the cemented annulus between the steel casing and the rock, until it encounters a permeable layer: at Hutchinson, the point of escape and lateral migration was a thin, fractured dolomitic horizon between two tight shale layers, into which the gas migrated and moved updip, toward the town.

In most cases there is an accumulation phase during which the escaped product progressively fills the receptor: pressure increases to reach equilibrium with cavern pressure. The products may remain in the outlet for a long period (Boling, Eminence where Cavern #7 leaks to the caprock); or product pressure may build up to a level such that a pathway is created to ground level (the outlet is the Doxey shales at Elk City; and the brine aquifer at salt top in the Conway case).

A poorly consolidated caprock above a salt dome, composed of insoluble blocks left by dissolution (of evaporitic

Table 4. Well ages in hydrocarbon storage leakage events.

Site	Date drilled (or debrined)	Incident date	Time span between creation and accident	Comment
Elk City, Oklahoma	Unknown. After 1954??	February 23, 1973	19 years?	Leak likely started as early as November 1972
Conway, Kansas	Beginning 1951	After 1956	5–60 years	The described accident in 2012
Yoder, Kansas	– Idem	June 30, 1980	30 years or more	
Mont Belvieu, Texas	1963	September 17, 1980 (wellhead pressure drop)	17 years	October 3, 1980 (fire)
Mineola, Texas	End of 1950's	2000?	50 years	Paper written in 2001
Hutchinson, Kansas	Drilled in 1980; Re-drilled in 1990	January 19, 2001	20 years	
Epe, Germany	1980	February 23, 2014	34 years	
Magnolia, Louisiana	1970's	December 24, 2003	33 years	6 weeks after repressurization
Eminence, Mississippi	1970–1973	26 December 2010	37–40 years	
Teutschenthal	1971	March 29, 1988	*c.* 17 years	
Boling, Texas	End of January 1983 (de-brined)	Fall 2005	*c.* 22 years	
Clute, Texas	Leached out in 1961	December 1988	*c.* 27 years	

minerals), is favourable to the development of a leak, on the one hand because it is the site of differential displacements in the casing (Sect. 3.1) and, on the other hand, because the caprock is *per se* a possible outlet. Revision of regulations in Texas took this fact into account. One might infer that leaks should be more frequent associated with salt dome storages rather than those in bedded salts.

In fact, among the 12 cases presented above, 7 are related to domal salts and 5 with bedded salt. Both cases are found in sedimentary environment, in which successions of tight and permeable layers commonly occur in the overburden. Mudstones and fine-grained siltstone interbeds are also found within massively bedded halite deposits. Therefore, above a bedded salt formation, as above a salt dome, intermediate aquifer layers (or, at least, more permeable layers, as in the Hutchinson case or at Elk City) overlain by a tighter overburden (Teutschenthal) are potential candidates for hosting an accumulation of leaking hydrocarbons. In addition, in a salt dome, the overburden has been deformed, which can aid fracture enhanced pathway development within the overburden succession; the caprock often is porous and permeable, making drilling and cementing a more difficult job.

4.2.2 A pressure differential is needed (leakage driving force)

In addition to a breach in the casing and a receptor horizon, development of a significant leak requires a driving force, *i.e.,* a pressure differential. At any depth, except maybe in the case of a natural gas storage when inventory is at a minimum, pressure of the stored product is larger than pore pressure in the rock mass (Fig. 15). The second condition for leak development, that of a pressure gradient driving the leakage flow, is always fulfilled. Density of the stored product plays a major role: the lighter the fluid, the larger the pressure differential between products pressure in the well and ground water pressure at leak depth; it is larger when the cavern is deeper and breach is shallower. This is especially true in the case of natural gas: when the cavern is full and gas pressure is at a maximum, it is higher than geostatic pressure at almost any depth above the casing shoe (Fig. 16); when a leak through a breach is created, it can find its way to ground level even through low permeability layers. Density also plays a role when considering effects at ground level, see below.

When leaking product migrates through the cemented annulus before reaching an outlet, pressure differential must

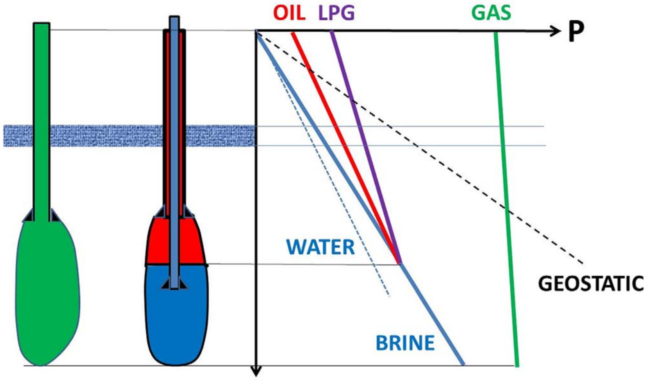

Fig. 15. Pressure distribution in the borehole in the case of a natural gas storage (green line) and in the case of an LPG or oil caverns (purple and red lines, respectively). Geostatic pressure and typical water pressure in aquifer layers are also represented.

be computed at receptor depth, where it is higher than at breach depth. At Hutchinson, on January 14, 2001, gas pressure was 4.76 MPa at casing shoe depth (238 m) and only slightly lower (hence, larger than geostatic) at the depth of the fractured layer through which gas escaped and spread, allowing fast leak rates.

4.2.3 Wellhead pressure drops

In several occurrences (Epe, Teutschenthal, Eminence, Boling, Mont Belvieu and Hutchinson), a pressure drop was observed at the wellhead:

- Epe (an oil storage), wellhead pressure dropped by 0.36 MPa 3 weeks before oil appeared at ground surface.
- Teutschenthal (an ethylene storage), pressure dropped from 7.5 MPa to 4 MPa: and ethylene blew out at ground level 1 h later.
- Eminence (a natural gas storage), pressure dropped by 2.56 MPa in 1 min.
- Boling (a natural gas storage), pressure drop was spread over one week, although natural gas did not appear at ground level and it is likely that gas found a porous and permeable level in the salt overburden.
- Mont Belvieu (an LPG storage) pressure dropped 20 days before an explosion occurred at ground surface.
- At Hutchinson (natural gas) the pressure dropped by 0.7 MPa follows the first blow-out *after* 15 min; the salty aquifer layer below the city of Hutchinson was an intermediate outlet in which gas accumulated and the pressure drop generated by the blow-out took 15 min to propagate to the S1 cavern, 13 km away.

No pressure drop is mentioned in other cases of Section 2, but one was also observed in Regina South Gas Storage Cavern No. 5 in Saskatchewan. The volume of this cavern, leached out in 1983–1984, was more than 700 000 bbls (45 000 m^3).

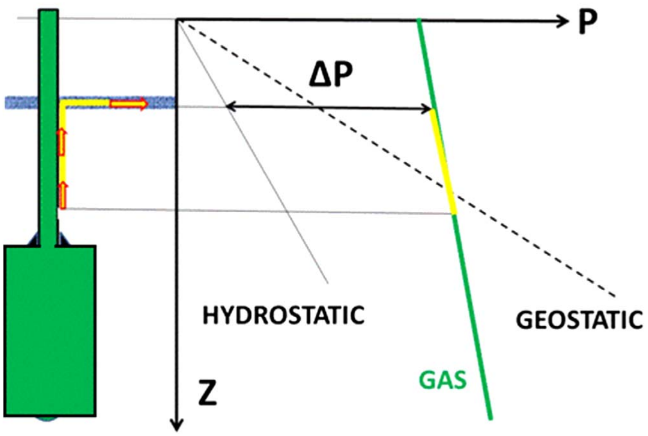

Fig. 16. A gas leaks from a breach in the casing. Gas migrates through the cement and reaches a shallower aquifer layer, at which point its pressure is much higher than *in situ* groundwater pressure and even, in many cases, higher than geostatic pressure.

> "Maximum pressure was 3000 psi (20.5 MPa), a relatively low value for a cavern whose roof depth was 5363 ft (1780 m). Roof salt thickness was 50 ft. The final developed roof position was higher than originally planned and located in a structurally unstable area with many thin insoluble bands. In July 1989, a 267-psig pressure drop occurred in this cavern following gas fill up to 3000 psig. A rate of change in pressure decline from the pressure *vs.* time graphs used to monitor cavern operating condition suggested the cavern roof had a leak away from the well bore (Crossley, 1998)."

A block fall generates no perennial gas pressure change; the pressure drop must be due to a gas leak to a porous and permeable layer above the salt roof.

Occurrence of a rapid pressure drop is especially puzzling in the case of a natural gas storage cavern. Gases are much more compressible than liquids and a large gas pressure drop requires the loss of a large fraction of the cavern inventory. When V is the cavern volume, the pressure drop due to a ΔV inventory loss is $\Delta P = \Delta V/\beta V$ where β is the factor of compressibility of the fluid-filled cavern (Bérest *et al.*, 1999); for a brine cavern, $\beta = 4 \times 10^{-4}$/MPa; for a propane filled cavern, $\beta = 10^{-3}$/MPa; for a gas-filled cavern, $\beta = 1/P$ where P is gas pressure, for instance $\beta = 10^{-1}$/MPa when gas pressure is 10 MPa. A $\Delta P = 0.5$ MPa pressure drop is generated by a 0.125% inventory loss in a brine cavern; in a gas cavern, the same pressure drop is generated by a 5% inventory loss – a huge value. For this reason, a large pressure drop in a gas cavern is possible only when the casing breach opens in a large, porous and permeable volume (Mont Belvieu); or, long after the breach is created, when the leaking gas reaches ground level or a large porous and permeable receptor. At Hutchinson, the pressure drop was observed 15 min after gas erupted in downtown Mont Belvieu – the time needed for the pressure drop in the salty aquifer below Mont Belvieu to propagate to the cavern breach.

4.2.4 Products viscosity, capillary effects

Leakage can affect all types of stored fluids, oil, natural gas, ethylene or LPG. A low viscosity and a low entry pressure in the rock formation favours leakage; as such, natural gas (and, *a fortiori*, hydrogen) may be more likely to leak than liquids. It is difficult to quantify how much more likely to leakage natural gas is as leak rate depends, in addition to gas viscosity, on the way a leak path develops. Leak flow is likely to be bi-phasic first, with a gas-water front inside which capillary pressures slow down gas migration rate, before a continuous path is created from breach to ground level or to an intermediate receptor. The storage industry (Crotogino, 1996) suggested empirical rules for conversion of a gas leak (which can be easily measured during a tightness test) into a liquid leak. Cases have been observed in which the cavern is found to be somewhat leaky when the testing fluid is a gas, but tight when it contains a liquid hydrocarbon. An example was at Magnolia, where the cavern did not pass a Nitrogen Mechanical Integrity Test, although the cavern had experienced no leakage issue when the annular space was filled with a much more viscous diesel oil (Bennett, 2009).

4.3 Eruption at ground level

4.3.1 The path toward ground level

One might think that a leak necessarily appears at ground level near the wellhead, *i.e.,* it follows the shortest path to surface. This was clearly the case at Mineola, from which it was inferred that the breach was shallow (the shoe of the penultimate casing was only 35.5-m deep) and at Eminence in 2011. However, in the general case, and especially when hydrocarbons accumulate first in an intermediate receptor (a porous layer or caprock, *e.g.,* Hutchinson, Teutschenthal, Clute, Elk City, Epe) the path found by the leak can be complex and surface release somewhat distant; it is often governed by geological features at shallow depth and is not always the shallowest path along a vertical line. In such a case, the blow-out can occur abruptly (Hutchinson, Elk City, Teutschenthal) and can be localized at a large horizontal distance from the wellhead (600 m at Elk City, 50–200 m at Teutschenthal, 500 m at Epe, and even up to 14 km in the exceptional case of Hutchinson); and, probably at a point where elevation is low (Mont Belvieu, Elk City).

At Hutchinson, general opinion is that a period of 8 years was needed for gas to charge a thin, 13-km long subhorizontal fractured level before gas erupted in downtown Hutchinson (several experts believe that filling took place over a few days prior to the eruptions, however, this conclusion is not fully substantiated by the (scarce) available information). At Teutschenthal, two distinct steps were observed: first, gas slowly filled an aquifer at 100-m–140-m depth, generating an uplift, and opening a new breach in the severely stretched casing. This led to a significantly increased leak rate, a pressure drop (from 7.5 MPa to 4 MPa) in the cavern and, 1 h later, a blow-out at ground level. Both the cavern and the intermediate receptor were vented by gas outflow at ground level, with ground uplift vanishing.

4.3.2 Effects at ground level

The effects observed at ground level depend on many factors, among which are the nature of the stored gas, the configuration of shallow layers, and local topography. Two types of effects can be observed: mechanical effects in case of an abrupt blow-out (Teutschenthal, or Elk City, where 30-tons rock blocks were uplifted; Yoder where, however, the propane/water jet was small) and chemical effects (Mont Belvieu, where the gas exploded; Hutchinson, where several explosions occurred). Importantly, no asphyxia case has been reported in the incidents discussed here. It is known from other types of incidents (wellhead failures, which often lead to a loss of the full cavern inventory – *e.g.,* Moss Bluff) that a natural gas blow-out, with high gas flow rates (gas velocity is sonic at ground level) is not an extremely severe hazard (except at the very beginning of the process) as natural gas, lighter than air does not spread laterally at ground level. In contrast, oil, and more generally liquids, remain at ground level and generate low-rate leaks (Epe), and do not burn in the absence of an ignition source. This may not be true when hydrocarbons spread over a large area of ground, as, above the liquid phase, a cloud forms containing the most volatile parts, ignition of which is easier. Ethylene, which is stored in a supercritical form, is gaseous at atmospheric pressure; its density is close to that of air, with which it forms an explosive mixture (however ethylene decomposes under the effect of light). At Clute, ethylene remained confined in the caprock. At Teutschenthal, it appeared haphazardly at ground level, however, topography and wind favoured dispersal. LPGs present a more difficult problem. In the cavern, they are liquid, but vaporize, at least partially, on their way to ground level when their pressure becomes lower than their vaporization pressure – at least when the flowrate is not too fast, and enough time is left for the rock mass to provide the heat needed for phase change. In their gaseous state, they are heavier than air (propane relative density is 1.5) and, at ground level, they tend to remain stagnant at low elevation points, or in building foundations (Mont Belvieu, Elk City). At Elk City effects of the blowout were mechanical rather than chemical; measurements proved that gas concentration at ground level was small (less than 1%).

4.3.3 Actions taken after a leak is found

After the occurrence of a leak is established, its origin must be confirmed (it could result from a breach in a buried pipeline). Gas composition often is a clue. Drilling boreholes to shallow ground water level, or to the level where products circulate, allows venting the gas and understanding the pathways followed by the leak (at Hutchinson, gas underground pathways, which were complex, were identified progressively; it was composed of several branches through which gas flowed toward the city).

When the leaking cavern is identified, it must be vented, when possible. At Boling, a temperature log identified the depth at which the leak took place, as gas depressurization creates a cold spot. Frequently, a plug is set in the wellbore, as deep as possible and hopefully below the leak level. A video log often assists in detecting this level, especially when the rupture was created by excessive tension on the cemented casing, or re-entry operations during well conversion damaged the casing (Hutchinson).

5 General lessons learned from case analysis for well monitoring

5.1 Pressure monitoring

Pressure monitoring at cavern wellhead is necessary; at Mont Belvieu, this monitoring provided a warning, 15 days before the blow-out. However, in most cases a pressure drop was not observed, or was observed too late, or even observed after the blow-out (Hutchinson), when the leak path was already fully developed. In principle, careful monitoring of the wellhead pressure over a long period should provide a warning; however, in a natural gas storage, the stored product is so compressible that pressure changes resulting from a leak are exceedingly small, especially when the cavern experiences frequent injection/withdrawal, the cumulative effects of which generate large uncertainties. In a strategic oil storage, the inventory of which changes little, a better resolution can be anticipated but important efforts must be made, in terms of accuracy and interpretation, to reach an acceptable resolution (Colcombet and Nguyen, 2013).

5.2 Well completion

The role of wellbore completion is extremely important. It was observed that the combination of a flat cavern roof and a short chimney leads to tensional stresses and stretching of the casing, especially when cavern creep closure is fast. In many of the described cases, a large difference can be observed between the depth of the deepest and penultimate cemented casing. In other words, between the shoes of these two casings, a single "barrier" (*i.e.,* a casing cemented to the rock formation) can be found: a breach through the steel casing opens directly to the rock mass. It is interesting to note that, in most cases, when repairing a leak, an inner steel tube is added to form, with the preexisting casing, an annular space the bottom to which is closed; this annulus is filled with water whose pressure is monitored at ground level – a way of creating a "second barrier" which did not exist in the initial design. Such a completion (an internal tube delimiting a monitoring annulus plugged at its bottom) has been mandatory in France and Germany for natural gas storages and the trend in Europe is to equip new liquid storage caverns with such a system (it is a requirement under Dutch mining law, Koopmans *et al.*, 2014). For many years in Texas, Louisiana and Kansas (three states in which can be found the majority of US salt cavern storages), State regulation has required that new caverns have two cemented casings, anchored in the salt formation. In addition, a tightness test is mandatory at least every 5 years, which covers the case of old caverns which are not equipped with a double casing.

5.3 Mechanical Integrity Tests (MITs)

Although the number of storage caverns in operation increases, fewer and fewer accidents are occurring. Several reasons exist for this. Recent caverns are equipped with a double casing anchored to the salt formations, or a water/brine-filled annular space. Both new and old caverns are now tested using the Nitrogen Leak Test (NLT) and Liquid Leak Test (LLT) methods. The former consists of injecting nitrogen into the annular space, the latter instead of nitrogen, a liquid hydrocarbon is injected. Salt caverns present a remarkable advantage (when compared to depleted reservoirs or, more generally, oil and gas fields): borehole tightness can be tested, as the borehole opens in a closed "container" (the cavern itself), which is almost perfectly tight. Typically, the NLT consists of injecting nitrogen into the annular space slightly below the last cemented casing shoe. A logging tool is used to measure the brine/nitrogen interface location. At least two measurements, generally separated by 3 days, are undertaken. Upward movement of the interface is deemed to indicate a nitrogen leak. Pressures are measured at ground level, and temperature logs are recorded to allow estimating effects such as thermal expansion and compressibility and enable precise back-calculation of nitrogen seepage. MITs are mandatory every five years in most US states and countries. Fail/Pass criteria have been proposed by the SMRI (Crotogino, 1996). Space does not permit expanding on these notions here, but MITs – and especially NLTs – are the most significant prevention tool in the cavern industry.

6 Conclusion

In this paper, based on a study funded by the SMRI, 12 incidents involving product leaks through the cemented casing of salt storage cavern wells are described. Their causes have been analyzed and general lessons drawn, which are informative for not only storage caverns, but also oil and gas field wells. They prove that experience, dissemination of new techniques and best practices, and advances in well design (double casing) and testing (MITs), leads to an ongoing reduction in the frequency and severity of incidents.

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