SALT CAVERNS AND THE COMPRESSIBILITY FACTOR

P. Bérest, B. Brouard, J. Bergues, J. Frelat, G. Durup⋆

Laboratoire de Mécanique des Solides
(Centre commun X-Mines-Ponts, U.R.A. 317 du C.N.R.S)
Ecole Polytechnique, 91128 Palaiseau Cedex
⋆ Gaz de France, 93211 Saint-Denis La Plaine Cedex

ABSTRACT

Cavern compressibility is the ratio between pressure build-up and injected brine in a closed cavern. This parameter is important in many circumstances, for instance the prepressurization before a nitrogen leak test or the estimation of LPG volume stored in a cavern. The theorical values of the compressibility factor are compared with field data. The case of gas pocket is considered. Possible misinterpretation of field data are discussed.

SALT CAVERN and the COMPRESSIBILITY FACTORS

CAVERN COMPRESSIBILITY AND COMPRESSIBILITY FACTOR

When a certain amount of liquid, ΔV, is injected in a closed cavern, the well-head pressure increases by ΔP (see Figure 1). The relation between the two quantities is, in general, fairly linear. A similar test can be performed by *withdrawing* a certain amount of liquid from a pressurized cavern.

An example is provided by a test described in Thiel (1993) — see Figure 2. The slope of the curve (brine pressure versus brine injected) is called the *cavern compressibility*:

$$\Delta V = \beta V \ \Delta P$$

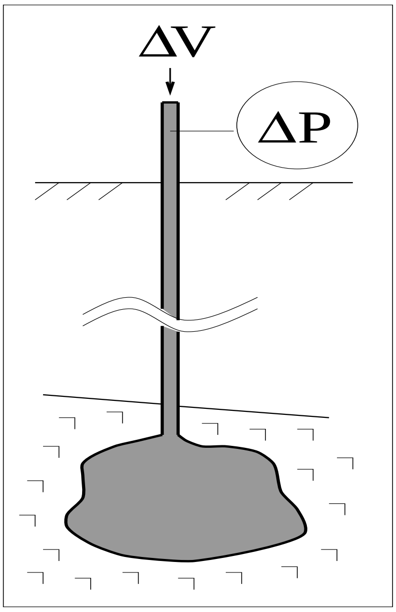
A convenient unit for cavern compressibility, βV, is m^3/MPa, or bbls/psi, with the conversion rules:

$$\begin{cases} 1 \text{ m}^3/\text{MPa} & \approx 0.043 \text{ bbls/psi} \\ 1 \text{ bbls/psi} & \approx 23.1 \text{ m}^3/\text{MPa} \end{cases}$$

It is sometimes convenient to use the *cavern stiffness*, which is the inverse of the cavern compressibility:

$$\Delta P = \frac{1}{\beta V} \ \Delta V$$

To what extent the compressibility, βV, can be influenced by test duration and other factors will be discussed later; Figure 2 proves that, from an engineer's point of view, the notion of cavern compressibility is defined sufficiently.



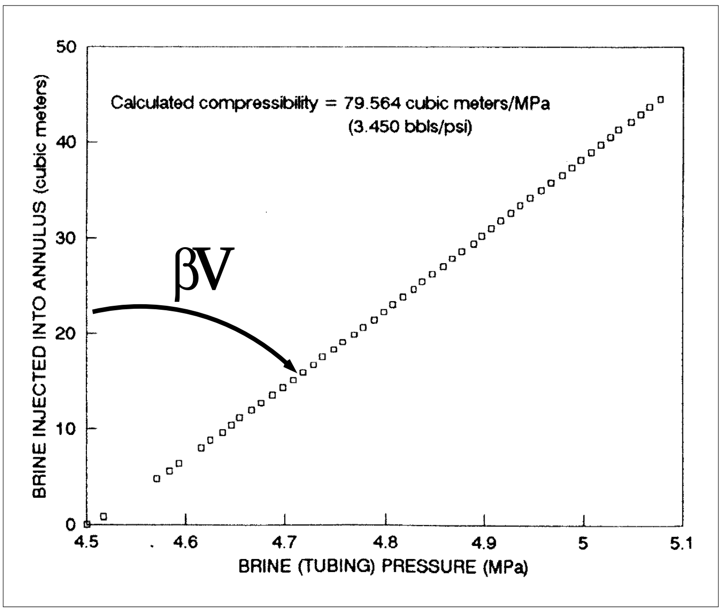


Figure 1: Measurement of the cavern compressibility
Figure 2: Prepressurization of a domal cavern [Thiel, 1993]

As a matter of fact, compressibility, βV, can be expressed as the product of the cavern volume, V (in m^3), and a *compressibility factor*, β (in vol/vol/MPa, or vol/vol/psi). The compressibility factor, β, is a constant — at least for caverns of similar shapes located in the same site and filled with the same fluid; in other words, β is not dependent upon the *size* of the cavern.

For instance, for the Etrez and Tersanne natural gas storage sites, Boucly (1982) has measured the compressibility factor:

$$\beta = 4.0\ 10^{-4}\ \text{vol/vol/MPa} = 2.8\ 10^{-6}\ \text{vol/vol/psi}$$

which must be considered as an average value (smaller values, from 3.4 10^{-4} MPa^{-1} to 3.9 10^{-4} MPa^{-1}, have been found in Tersanne caverns).

Similarly, for the case of the Manosque oil storage site, You and Colin (1990) give the measured compressibility factor for brine filled caverns:

$$\beta = 5.0\ 10^{-4}\ \text{vol/vol/MPa} = 3.4\ 10^{-6}\ \text{vol/vol/psi}$$

For the caverns of the Vauvert site, Valette et al. (1994) have measured values of β scattered between $\beta = 3.2\ 10^{-4}$ vol/vol/MPa to 8.5 10^{-4} vol/vol/MPa, which does not seem consistent with the statement of constant β for a given site. In this particular case, however,

(i) the caverns are very deep, resulting in large creep rates,
(ii) the salt formation is probably gassy, and
(iii) caverns develop between two wells linked by hydrofrac,
which can explain the different behaviors.

THE COMPRESSIBILITY FACTOR

We first consider the case of a brine-filled cavern. Let M be the cavern brine mass:

$$M = \rho_b V$$

where ρ_b is the brine density, and V is the cavern volume.

When the cavern pressure increases by ΔP, the following occurs.

1. The brine density increases by $\rho_b \beta_b \Delta P$, where β_b is the brine compressibility factor. It does not depend upon cavern shape or cavern volume.

2. The cavern volume increases by $V \beta_c \Delta P$, where β_c is the cavern compressibility factor, which depends upon rock-mass elastic properties and cavern shape (but *not* upon cavern volume).

Then, if an additional mass of saturated brine, $m = \rho_b \Delta V$, is forced into a closed cavern, its pressure will increase by

$$M + m = (\rho_b + \Delta\rho_b)(V + \Delta V)$$

or

$$\beta V \Delta P = \Delta V \qquad ; \qquad \beta = \beta_b + \beta_c$$

Cavern compressibility is the sum of the brine compressibility factor, β_b, and the cavern compressibility factor, β_c.

THE CAVERN COMPRESSIBILITY FACTOR

Cavern compressibility factor, β, obviously depends upon both rock-salt elastic properties and cavern shape.

1. Theoretical Analysis

For simple cavern shapes, some analytical calculations can be made. If E is the Young's modulus of the salt, and ν is the Poisson's ratio, we get the following.

⋆ *For a* **spherical** *cavity* :

$$\beta_c = \frac{3(1+\nu)}{2E}$$

⋆ *For a* **infinite cylindrical** *cavity* :

$$\beta_c = \frac{2(1+\nu)}{E}$$

⋆ *For a* **real-world** *cavern*,

$$\beta_c = f \ . \ \frac{(1+\nu)}{E}$$

where f is a *shape factor*. (f is always greater than 3/2, which corresponds to the spherical case, which is the less compressible shape of a cavern. In the case of the Te04 cavern (See Figure 3) Gaz de France computed a $f = 1.6$ shape factor).

Results of calculations using a finite-element code for simple shapes are given on Figures 4 through 6.

From Figure 4 it is clear that a cylindrical cavern with an aspect ratio (height divided by diameter, H/D) larger than 1 behaves as an infinite cylinder, $\beta_c \approx 2(1+\nu)/E$. In contrast, a flat cylinder, $(H/D < 0.5)$, is much more compressible.

Figure 5 illustrates that an oblate spheroidal cavern (b/a is large) behaves as a cylindrical cavern ($\beta_c \approx 2(1+\nu)/E$). When $b = a$, we get the spherical case, $\beta_c = 1.5(1+\nu)/E$. When the cavern becomes prolate (flat), the cavern compressibility factor drastically increases.

Typical "cylindrical" caverns, $f = 2$ are Eminence caverns (Figure 7) and a typical "flat" cavern is West Hackberry n^{o}6 (Figure 8).

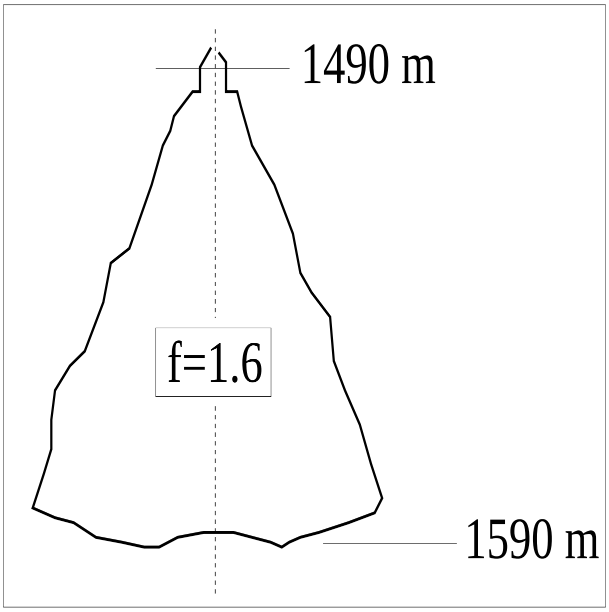
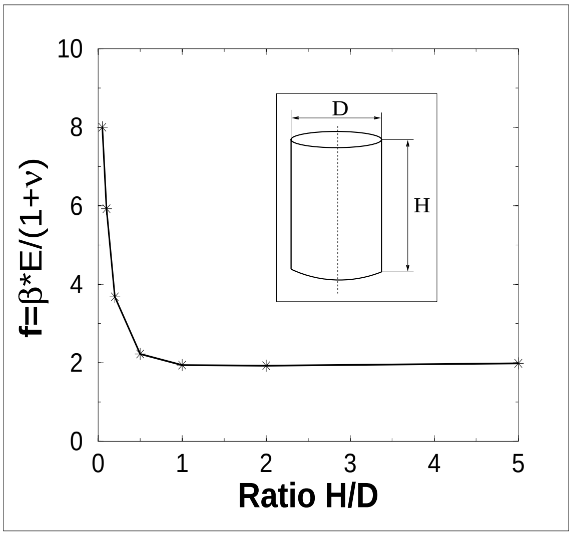


Figure 3: Cavity Te04 from Tersanne (Gaz de France)



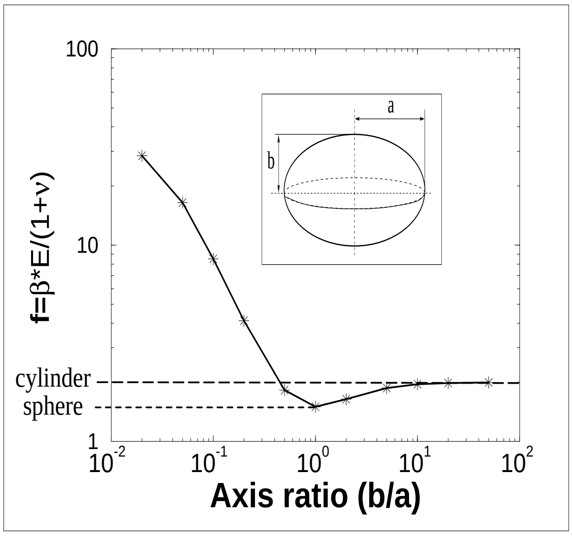


Figure 4: Cavern compressibility factor for a cylindrical cavern

Figure 5: Cavern compressibility factor for a spheroidal cavern

2. **Field Data**

From compressibility factor data, Boucly (1982) infers that $\beta_c = 1.3\ 10^{-4}$ MPa^{-1} (9.0 10^{-7} psi^{-1}), which is consistent, for instance, with the following estimations:

$$\begin{cases} \nu = 0.3 \\ E = 17,000 \text{ MPa} \\ f = 1.7 \end{cases}$$

The shape-factor value corresponds to a cavern whose shape is intermediate between cylindrical and spherical shapes. For the Tersanne and Etrez caverns considered by Boucly, see Figures 3 and 9.

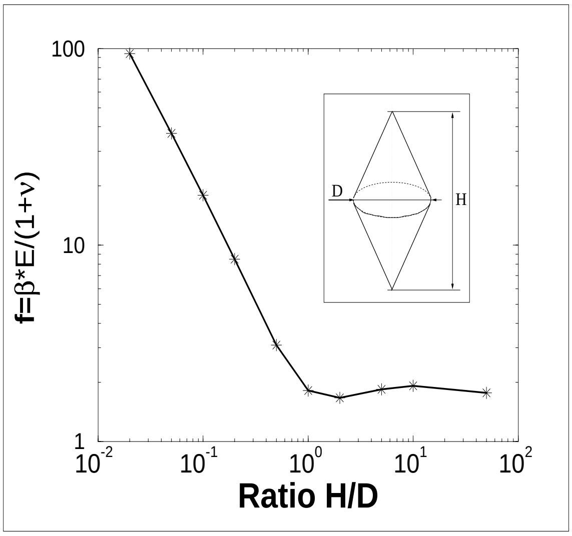
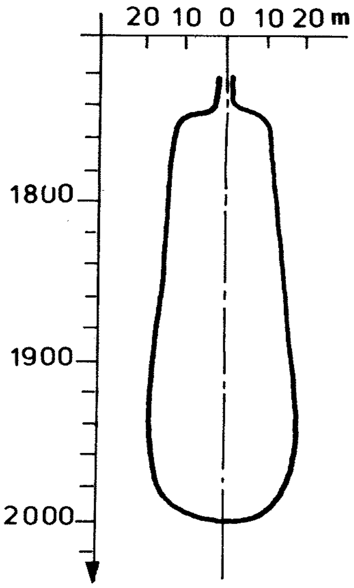


Figure 6: Cavern compressibility factor for a double-cone-shaped cavern

The elastic properties of rock salt can vary from one site to another; reasonable ranges of variation are

$$\begin{cases} 5,000 \text{ MPa} \leq & E & \leq 40,000 \text{ MPa} \\ 0.25 \leq & \nu & \leq 0.3 \end{cases}$$

With such figures, the cavern compressibility factor can vary from $\beta_c = 0.5\ 10^{-4}\ \text{MPa}^{-1}$ to $\beta_c = 4\ 10^{-4}\ \text{MPa}^{-1}$ for a spherical cavern (the less compressible shape) and up to 4 or 5 times more for flat cavern.



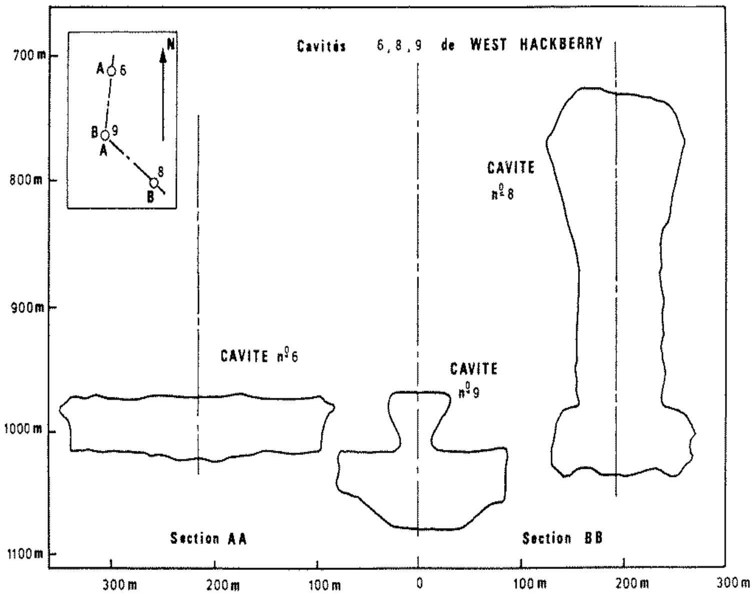


Figure 7: Eminence (a "cylindrical" cavern)
Figure 8: West Hackberry (a "flat" cavern, n^{o}6)

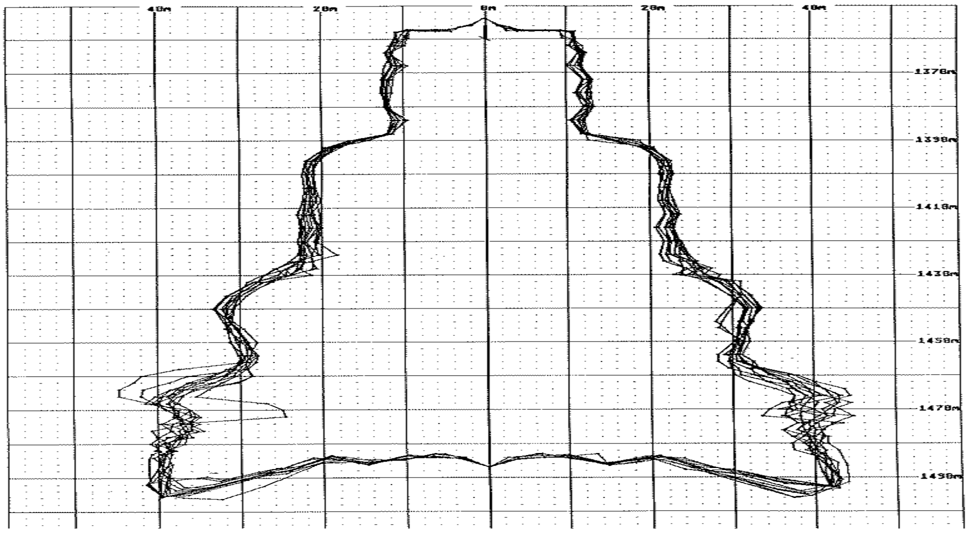


Figure 9: Cavity Ez15 from Etrez (Gaz de France)

THE FLUID COMPRESSIBILITY FACTOR

1. Brine

The theoretical brine compressibility factor is related to the sound of speed through the relation $\rho_b \beta_b c_b^2 = 1$, where $\rho_b = 1200$ kg/m^3, $c_b = 1800$ m/s; thus , $\beta_b \approx 2.57\ 10^{-4}$ MPa^{-1}. This figure is a little too small, because the brine saturation concentration is modified by pressure change: pressure build-up triggers additional cavern leaching, as noted, for instance, by Linn and Ehgartner (1994), and increases the cavern volume, resulting in a slightly higher effective brine compressibility. A reasonable value for the brine compressibility factor is in the range of $\beta_b = 2.7\ 10^{-4}$ MPa^{-1} ($1.9\ 10^{-6}$ psi^{-1}) — see, for instance, Boucly (1982) or Crotogino (1981).

2. Hydrocarbons

Hydrocarbons are much more compressible than brine or water. Their compressibility factor is influenced by pressure and temperature. A typical value for propane at 25^{o}C and 7 MPa is

$$\beta_{prop} \approx 2.9\ 10^{-3}\ \mathrm{MPa}^{-1}$$

3. Nitrogen and Other Gases

As long as only slow evolutions are considered, gas evolutions can be considered to be isothermal; for an ideal gas (which nitrogen is, for the most part), the compressibility factor is simply the inverse of the (absolute) pressure, P:

$$\beta_{gas} = 1/P$$

This means that the compressibility factor of a gas pocket trapped at the top of a brine-filled cavern (where the pressure, for instance, is 12 MPa at 1000 meters), will be

$$\beta_{gas} \approx 8.3\ 10^{-2}\ \mathrm{MPa}^{-1} = 1/12\ \mathrm{MPa}^{-1}$$

and the compressibility factor of a gas bubble trapped at the well-head, where the absolute pressure is 0.1 MPa, will be

$$\beta_{gas} = 10 \text{ MPa}^{-1}$$

4. **The Case of Several Fluids in a Cavern**

• Theoretical aspects

In a storage cavern, the cavity contains brine *and* another fluid (such as propane or oil). In this case, the global fluid-compressibility factor will be a certain average of the compressibility factors of the different fluids: β_b (for brine) and β_h (for hydrocarbon). Let x be the cavern volume fraction that is occupied by the other fluid [i.e., if V is the cavern volume, the fluid volume is xV and the brine volume is $(1-x)V$]. Then, the global fluid compressibility factor β_F will be

$$\beta_F = (1-x)\beta_b + x\beta_h$$

and the compressibility factor, $\beta = \beta_c + \beta_F$, will vary to a large extent with respect with the hydrocarbon volume fraction. Consider, for instance, the case of propane storage. If we take

$$\begin{cases} \beta_c = 1.3\ 10^{-4} \text{ MPa}^{-1} \\ \beta_b = 2.7\ 10^{-4} \text{ MPa}^{-1} \\ \beta_{prop} = 2.9\ 10^{-3} \text{ MPa}^{-1} \qquad \text{(propane)} \end{cases}$$

then

$$\beta = \beta_c + \beta_b + x(\beta_{prop} - \beta_b)$$

and the compressibility factor varies from $\beta = 4.\ 10^{-4}$ MPa^{-1} (no propane in the cavern) to $\beta = 25\ 10^{-4}$ MPa^{-1} (propane fills 80% of the cavern).

• Example

The SPR1 cavern in the Carresse site (in the southwest of France) is used by the SNEA(P) company to store propane. The casing shoe depth is 348 meters below ground level; the cavern bottom depth is 381.5 meters. This cavern volume is 13,000 m^3 (as measured in 1992). Compressibility factor measurements have been performed at two different periods. Measurement of the compressibility factor allows the propane volume in the cavern to be checked, see Figure 10.

5. **The Case of a Gas Pocket in a Cavern**

If a gas pocket is trapped in the cavern, the compressibility factor drastically increases, even if the pocket volume is small.

The SPR3 cavern of the Carresse site is deeper than SPR1; the casing shoe depth is 692 meters below the ground level, and the cavern bottom depth is 711 meters. The cavern volume is 4600 m^3. A 1995 sonar survey performed a few months before the test proves that this cavern exhibits a non-convex shape (Figure 11). The compressibility

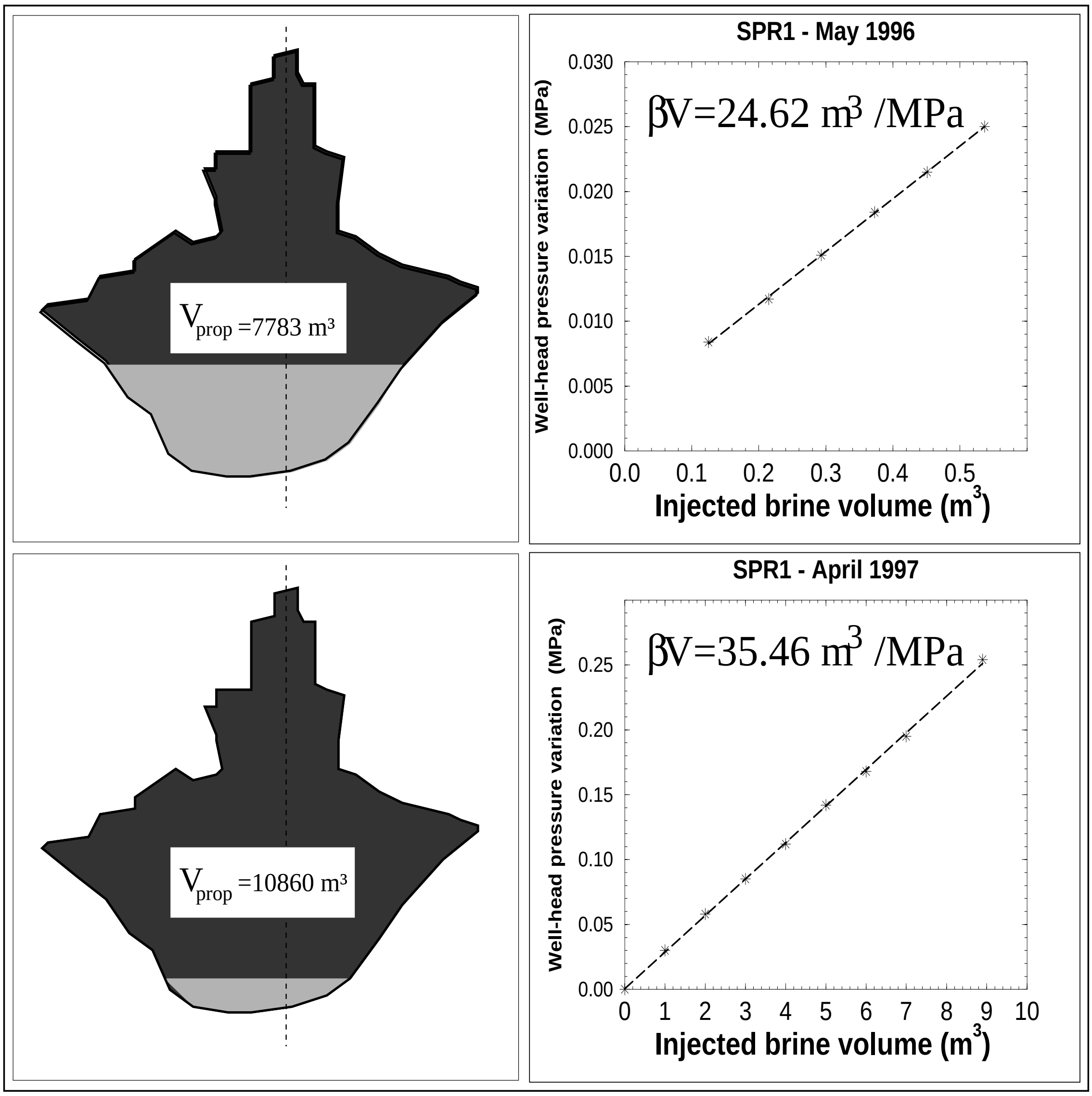


Figure 10: Two tests on the SPR1 cavern. (The compressibility factor is influenced by the stored propane volume.)

factor observed during the test was $\beta = 11\ 10^{-4}$ MPa^{-1}, which appears abnormally high for a brine-filled cavern. It soon appeared that this high figure was reasonably explained by the presence of gas, coming from the salt formation or from the brine used for cavern leaching, which was trapped in gas pockets under the bell-shaped parts of the cavern. These pockets are clearly visible on the left and top of the cavern on Figure 11. The gas pressure at cavern depth is 8.3 MPa, which means that its isothermal compressibility factor is $\beta_{gas} = 1.2\ 10^{-1}$ MPa^{-1}. The volume of the gas pocket can be back-calculated: it is approximately 25 m^3, or $x = 0.5\%$ of the cavern volume.

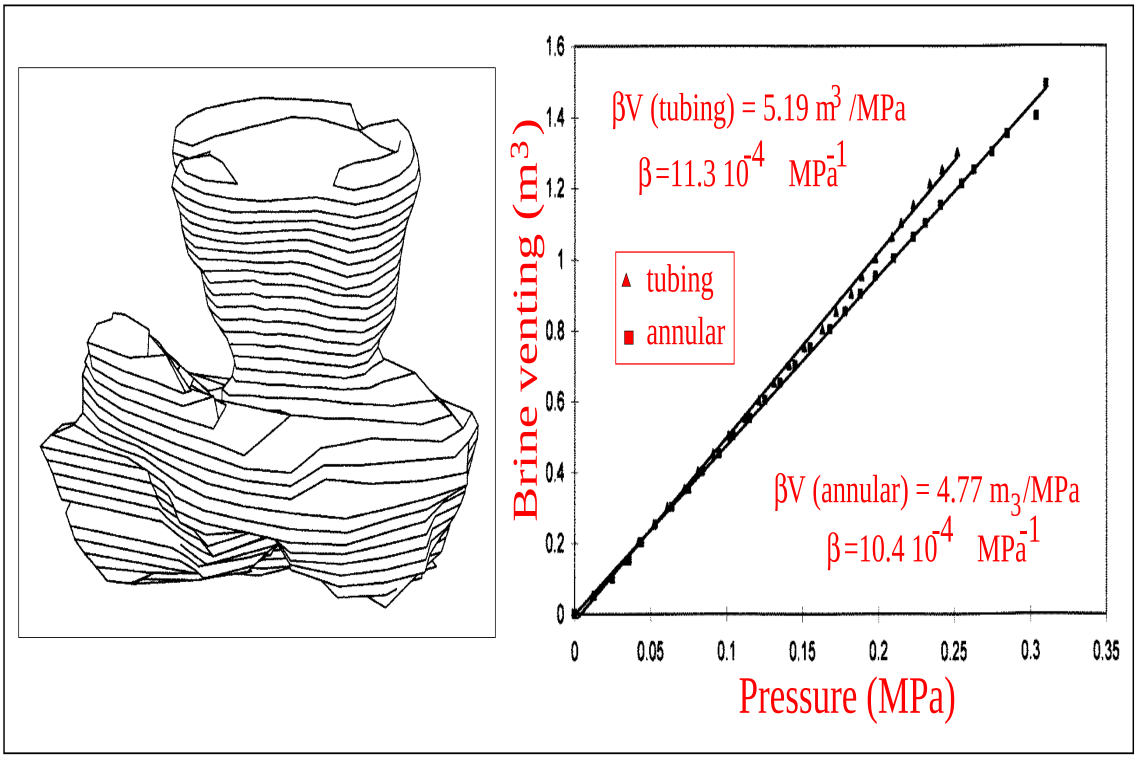


Figure 11: A test on the SPR3 cavern.

PHENOMENA INFLUENCING THE MEASUREMENT OF CAVERN COMPRESSIBILITY

1. Column Weight Changes

We assume here that brine is injected (or withdrawn) in (or from) the central tubing and we compare the cavern well-head pressure as measured in the annular space, (P_{ann}), and in the central tubing, (P_{tub}). The pressure variation, ΔP_{ann}, in the annular space during an injection (or withdrawal) test is exactly equal to the pressure variation, ΔP_c, in the cavern, because the composition, temperature, and concentration of the fluid column in the annular space do not change during the test. In other words, pressure changes in the cavern are exactly and precisely transmitted through the annular space to the annular well-head. The same cannot be said of the brine column in the tubing space (Figure 12). In many cases, the injected brine is not fully saturated (because, for example, it is stored at ground level and can be lightened by rain waters), resulting in significant variations of the brine column weight.

We assume that the density of the injected brine is slightly smaller than the density of saturated brine; for instance , $\rho_b = 1180$ kg/m^3 instead of $\rho_{sat} = 1200$ kg/m^3, which results in a ($\delta\rho = 20$ kg/m^3)-gap in densities. This means that when a volume of brine equal to ΔV is injected in the cavern, the injected-brine/saturated-brine interface decreases by $h = \Delta V/S$, and the cavern pressure (and annular space pressure) changes by

$$\Delta P_{ann} = \Delta P_c = \frac{\Delta V}{\beta V} = \frac{S\ h}{\beta V}$$

The tubing pressure, however, changes by

$$\Delta P_{tub} = \Delta P_{ann} + \delta\rho g h$$

due to change in the brine column weight.

In other words, provided that the injected brine volume, ΔV, is smaller than the tubing volume, we get a relative error, e, by measuring the tubing pressure:

$$e = \frac{\Delta P_{ann} - \Delta P_{tub}}{\Delta P_{ann}} = \frac{\beta V \ g \ \delta\rho}{S}$$

Reasonable values are, thus, $g = 10$ m.s^{-2}, $S = 2\ 10^{-2}$ m^2. For a brine-filled cavern, $\beta = 4\ 10^{-10}$ Pa^{-1}; then, e, made by measuring the tubing brine pressure instead of annular brine pressure, is a function of cavern volume (V) and brine distance to saturation ($\delta\rho$):

$$e = 2\ 10^{-7}\ V\ (\text{in m}^3)\ \delta\rho\ (\text{in kg/m}^3)$$

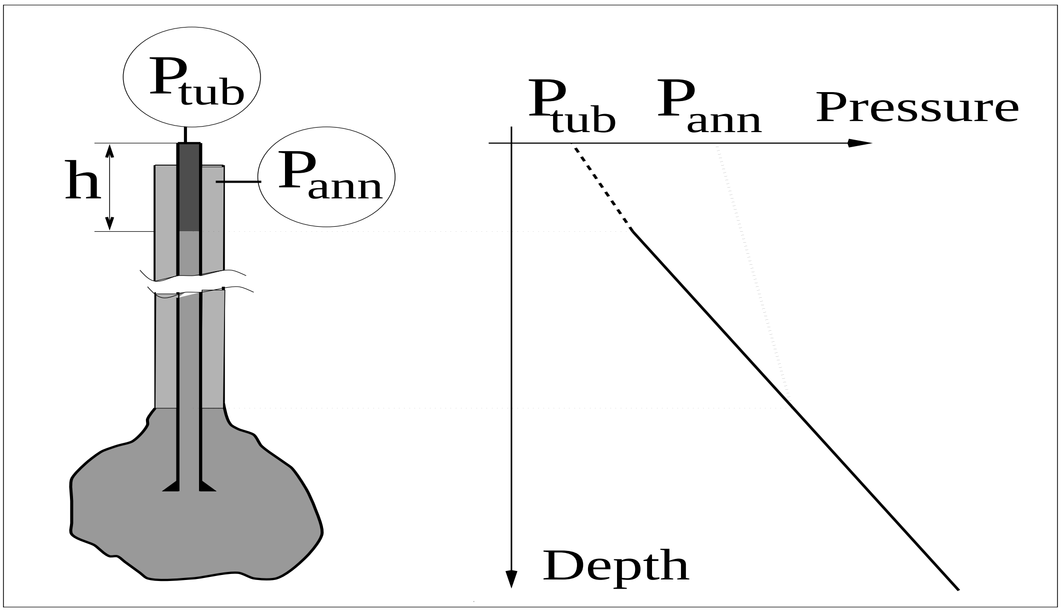


Figure 12: Injection of non-saturated brine at well-head

Large under-estimations of cavern compressibility can be made by measuring the pressure variations on the wrong tube (Figure 13). They can be avoided by either

(i) measuring the well-head pressure variations in the annular space, or
(ii) pressurizing the cavern and performing a test by withdrawing (instead of injecting) brine (but transient creep effects can be a drawback, see 3.)

2. **Brine Heating and Brine Percolation**

Due to brine heating, an opened cavern expels brine [or pressure builds up in a closed cavern (Brouard and Berest, 1995a)]. This effect is most significant when the cavern has been recently leached; a typical value is 200 liters/day for a 8000 m^3 cavern (Hugout,

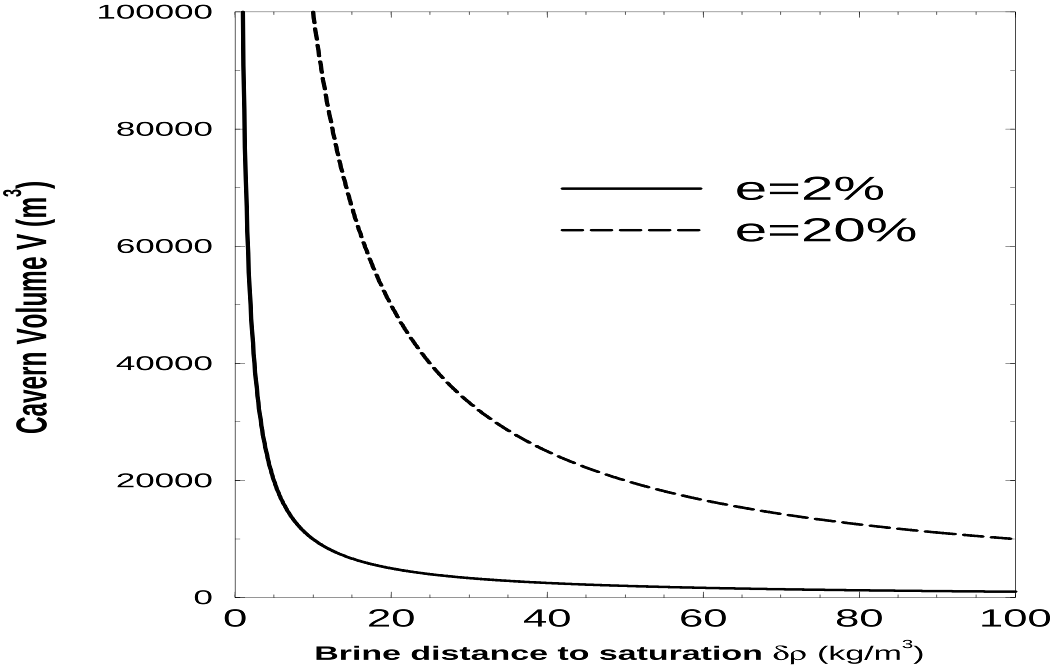


Figure 13: Under-estimations of the cavern compressibility βV due to injection of unsaturated brine in the well and pressure measurement through the tube (and not the annular space).

1988). This figure is proportional to the cubic root of the cavern volume; for instance, the rate will be 800 liters/day in a 500,000 m^3 cavern. This means that injection test results will be seriously affected if the injection rate is smaller than, say, 1 m^3/h. In many cases, the injection rate is faster, and brine heating is not a serious concern. The same can be said of steady-state creep (Transient creep will be discussed later.), except for very deep caverns (2000 meters below ground level). Finally, brine percolation (Berest and Brouard, 1995a), which is a real concern for tests performed in wells, before leaching, does not seem to be a large influence, except perhaps in some very specific cases. An example is described in Istvan et al. (1997).

3. **Transient Creep**

Steady-state creep is, in most cases, negligible: it is too slow to bring significant perturbations during a pressurization or depressurization test, except for the possible case of a very deep cavern (2000 meters below ground level).

However, a rapid change of pressure as it exists during a compressibility test triggers transient creep that can be of bigger concern from the perspective of test accuracy. This effect is more pronounced during depressurization, as has been observed by Dubois and Clerc-Renaud (1980) in the Manosque (France) facility:

> "Starting from the normal operating situation (overpressure in the annulus) oil is removed in order to decrease the well-head pressure. The base of the cavity is always at 1000 meters. At the beginning, the decrease of the well-head pressure is proportional to the volume of oil removed [Figure 14]. After the point b, the decrease is slower. Point b is the beginning of the creep. In

fact, the position of point b depends on the rate of oil removal and the depth of the cavity"

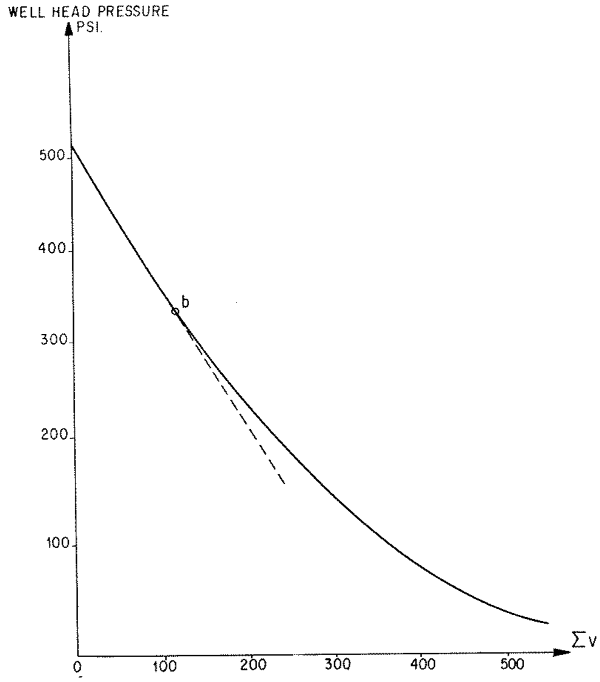


Figure 14: Depressurization of a cavity. (Well-head pressure versus cumulative withdrawal volume) [after Dubois and Clerc-Renaud, 1980]

In order to simulate such a phenomenon, we have used the transient creep constitutive law proposed by Gaz de France [Hugout (1988)]. We made calculations for the case of a 100,000 m^3 cavern at a 1000 meters depth, the pressure decrease rate is 1 MPa/hour.

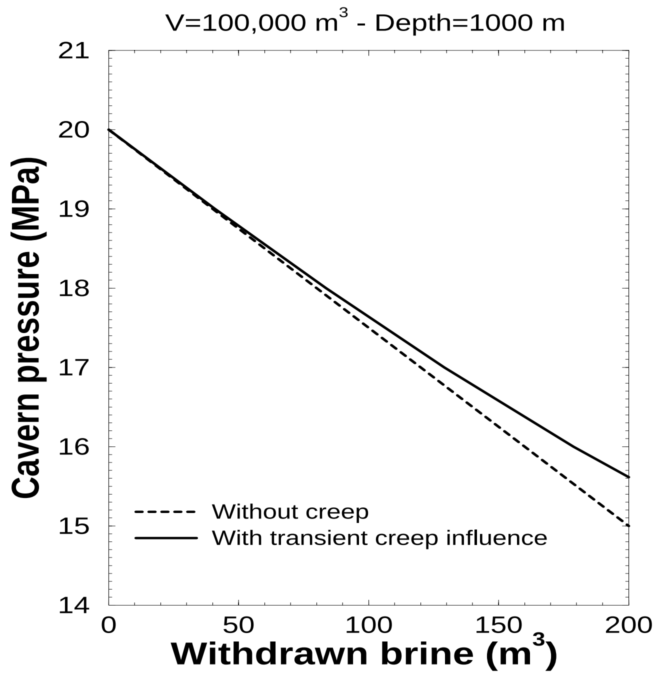


Figure 15: Transient creep effect

APPLICATIONS

1. VOLUME OF FLUID LOST DURING A BLOW OUT

Neal E. Van Fossan remarks that "there have been no wellhead failures recorded by industry. It is deemed highly unlikely that any accident failure of a wellhead would occur". However, during special operations in oil- or gas-filled caverns, eruptions can result in failure of the sealing-off equipment. Such a case is described in a U.S. DOE report and discussed by Berest (1990). From the perspective of risk analysis, it is important to evaluate the volume of fluids that would be released from the cavern upon total decompression.

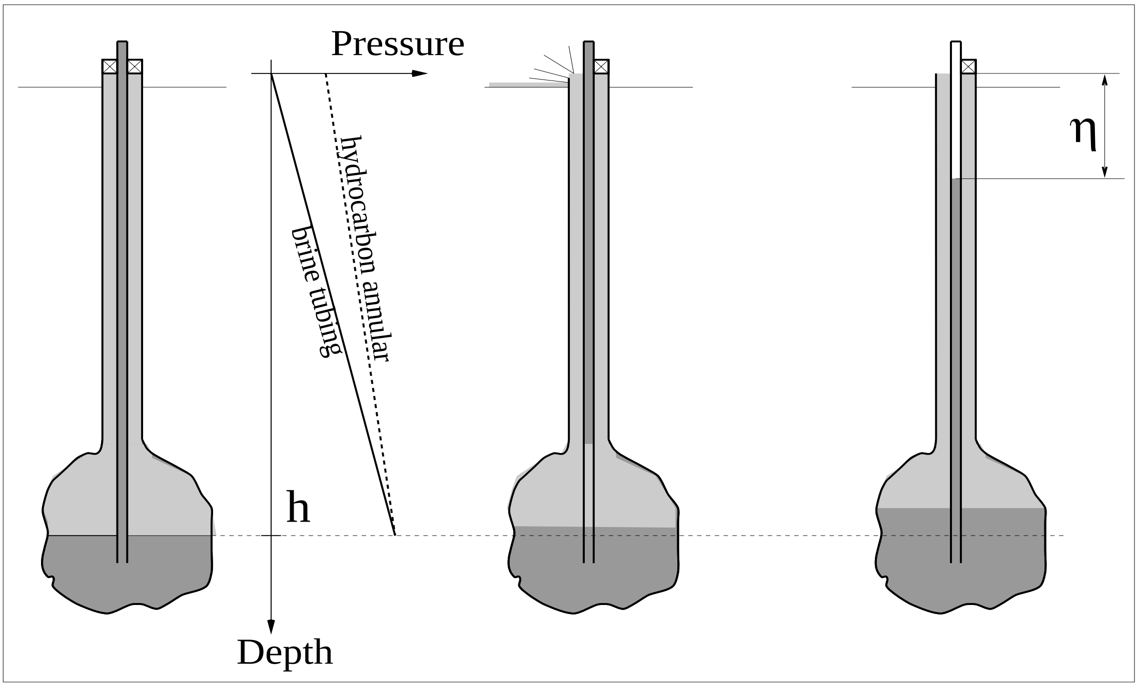


Figure 16: Blow out movie

If ρ_F is the hydrocarbon density and ρ_b the brine density, and if the brine at the well-head is submitted to atmospheric pressure, then the hydrocarbon pressure at the well-head is a linear function of the interface depth h:

$$P_{hyd} = (\rho_b - \rho_F)gh$$

After failure of the well-head, hydrocarbon pressure will drop to zero and the brine level in the central tube will fall to a depth, η, such that the weight of the two fluid columns balance

$$\eta = h\,\frac{\rho_b - \rho_F}{\rho_b}$$

The volume of fluid expelled from the cavern is mainly due to fluid decompression in the cavern:

$$V_{exp} = \beta V(\rho_b - \rho_F)gh$$

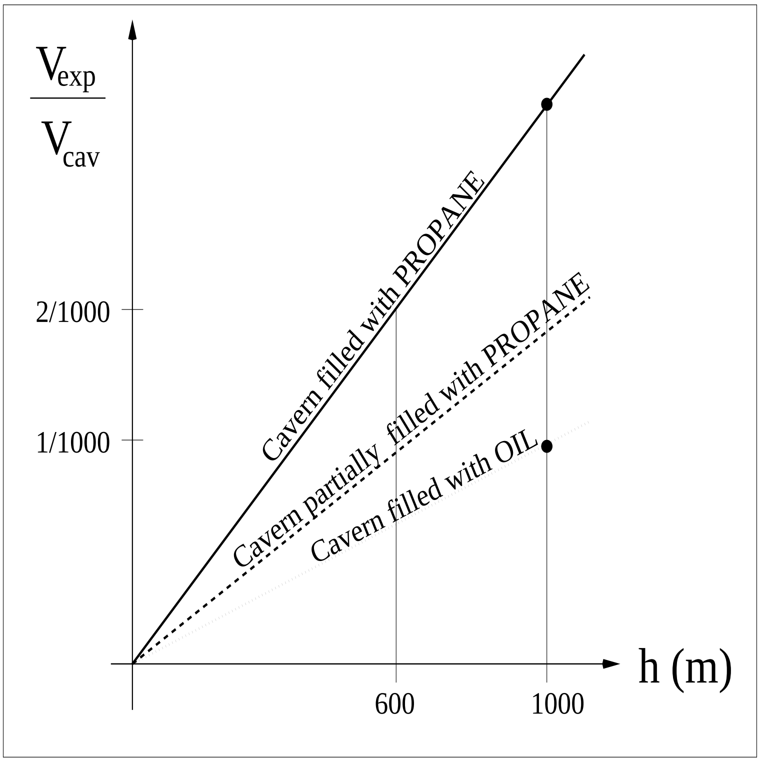


Figure 17: Relative product volume expelled during a blow out

where βV is the average cavern compressibility.

For oil storage in a 1000-meter deep cavern, the relative volume of oil expelled, following well-head failure, would be 1.2 10^{-3} (or 600 m^3 for an oil-filled 500,000 m^3 cavern). For propane storage in a 600-meter deep cavern, the relative volume of propane expelled would be 1.9 10^{-2} (or 945 m^3 from a propane-filled 50,000 m^3 cavern).

In the latter case, the LPG volume would be expelled in liquid form and would evaporate after running over the ground. Afterward, evaporation would continue inside the well itself at a much slower rate.

References

[1] Berest P. *Accidents in underground oil and gas storages: case histories and prevention.* Tunneling and Underground Space Technology, Vol. 5, n°4, pp. 327-335, 1990.

[2] Berest P. Brouard B. *Behavior of sealed solution-mined caverns.* SMRI Spring Meeting, New Orleans, 1995.

[3] Berest P., Brouard B. Durup G. *Some comments on the MIT test.* SMRI Fall Meeting, San Antonio, 1995.

[4] Boucly P. *Expériences in situ et modélisation du comportement des cavités utilisées pour le stockage du gaz.* Revue Francaise de Géotechnique-n°18, 1982.

[5] Clerc-Renaud A. Dubois D. *Long term operation of underground storage in salt.* Fifth Symposium on Salt, vol. II, pp. 3-12, 1980.

[6] Colin P. You T. *Salt Geomechanics seen through 20 years experience at the Manosque Facility.* S.M.R.I. Fall Meeting, 1990.

[7] Crotogino F.R. *Salt Cavern In-Situ Testing from the constructor's and the operator's viewpoint.* 1st Conf. Mech. Behavior of Salt-Hardy and Langer ed. Trans Tech Pub., 1981.

[8] Behrendt C. Crotogino F.R., Hackney J. *SMRI-Bibliography for Cavern Abandonment.* To be published in 1997.

[9] D.O.E. *Strategic Petroleum Reserve West Hackberry Oil Strorage Cavern Fire and Spill.* After Action Report, vol. I.

[10] Ehgartner B.L. Linn J.K. *Mechanical Behavior of Sealed SPR Caverns.* SMRI Spring Meeting, 1994.

[11] Hugout B. *Mechanical Behavior of salt cavities -in situ tests- model for calculating the cavity volume evolution.* 2nd Conf. Mech. Behavior of Salt, Hannover, Hardy and Langer ed., pp. 291-310, Trans. Tech. Pub., 1988.

[12] Istvan J.A., Evans L.J. Weber J.H. *Rock Mechanics for Gas Storage in Bedded Salt Caverns.* Proc. 36th US Rock Mech. Symp., Int. J. Rock Mech. Min. Sci., Vol.34, p. 647, paper 142, 1997.

[13] Thiel W.R. *Precision methods for testing the integrity of solution mined underground storages caverns.* Seventh Symposium on Salt, vol. I, pp. 377-384, 1993.

[14] You T., Maisons C. Valette M. *Experimental Procedure for the Closure of the Brine Production Caverns on the "Saline de Vauvert" Site.* SMRI Fall Meeting, 1994.