Pressure perturbations from geologic carbon sequestration: Area-of-review boundaries and borehole leakage driving forces

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Abstract

We investigate the possibility that brine could be displaced upward into potable water through wells. Because of the large volumes of CO_2 to be injected, the influence of the zone of elevated pressure on potential conduits such as well boreholes could extend many kilometers from the injection site—farther than the CO_2 plume itself. The traditional approach to address potential brine leakage related to fluid injection is to set an area of fixed radius around the injection well/zone and to examine wells and other potentially open pathways located in the “Area-of-Review” (AoR). This suggests that the AoR needs to be defined in terms of the potential for a given pressure perturbation to drive upward fluid flow in any given system rather than on some arbitrary pressure rise. We present an analysis that focuses on the changes in density/salinity of the fluids in the potentially leaking wellbore.

1. Introduction

The possibility of buoyancy-driven CO_2 leakage from geologic carbon sequestration (GCS) sites is well known and has gathered a lot of attention in studies of long-term fate of CO_2 and risk assessment of GCS. Another hazard, common to all injection operations and which has not been as widely publicized in the context of GCS, is that of widespread pressure perturbation in the formation arising from the injection process. In general, the injection formation accommodates the additional mass forced into it primarily by (1) increasing fluid pressure, (2) displacing the brine at the formation boundaries if open, and (3) uplift of the land surface. In this paper, we focus on the first mechanism. The second issue is addressed in Nicot [1] and Nicot et al. [2]. Because of the large volumes of CO_2 that need to be injected for industrial-scale GCS and of the associated possible pressure overlap between projects, the influence of the zone of elevated pressure during injection on potential conduits such as well boreholes and faults could extend many kilometers from the injection site—much farther than the CO_2 plume itself. Formation brines could endanger water resources if pushed upwards along those conduits. It should be noted that large injection operations are widespread in the oil and gas industry but are generally less of a concern because they involve re-injection of produced waters, i.e., injectate replaces fluids being produced such as oil, gas and water.

U.S. environmental regulations call for protecting aquifers and subsurface water bodies (sometimes called Underground Sources of Drinking Water –USDW) with a Total Dissolved Solids (TDS) of <10,000 mg/L from accidental intrusion by higher salinity water (TDS >10,000 mg/L). Under the current Underground Injection Control program, the U.S. Environmental Protection Agency (EPA) requires that the permit applicant define an *Area of Review* (AoR) in which all penetrations intersecting the injection formation or its confining layer be identified and be determined to have been properly plugged and abandoned. The AoR is either assigned a fixed radius of ¼ mile (400 m) for Class II enhanced recovery wells and 2 miles for Class I hazardous waste wells (could be larger in some states with primacy, for example 4 km –2.5 miles– in Texas) or computed as the edge of the pressure front, whichever is larger. Because injected CO_2 volumes are likely to be large and because of buoyancy effects, the elevated pressure footprint of CO_2 injection projects may not have a radial symmetry and suggest that computer models should be used to determine the edge of the AoR. Interferences between multiple injection projects also add to the complexity of defining the shape of the AoR. EPA defined the edge of the computed AoR as the set of points at which the maximum pressure at any time is able to lift the formation water to the base of the USDW. The recent EPA draft regulations on AoR for Class VI CO_2 injection wells also suggest it should be defined similarly to Class I and Class II wells since they are also driven by pressure. In addition, the draft regulations explicitly state that the pressure plume may not have an approximately radial symmetry.

This short paper does not address all of the AoR issues but makes a contribution by analyzing the degree to which density-stratified water in a wellbore can be displaced upwards by elevated pressure associated with GCS both during injection and after injection. Its narrower objective is to understand the amount of additional pressure that can be sustained by a borehole connecting the saline water-bearing injection formation and fresh water aquifers before the former contaminates the latter. The focus is on the edge of the elevated pressure area where pressure increase can be balanced by changes in fluid density when the borehole is partially invaded by saline water following the pressure pulse. Determination of such an admissible maximum pressure could help in defining the extent of the AoR.

2. Water Profile in a Wellbore

Formation TDS is generally described as increasing with depth as residence time, mixing with brines, and reaction with minerals occur. The statement is more strictly true when the increase in depth is combined with migration in the downdip direction along one single formation. This is true too along a vertical profile but with more variations depending on the presence of faults, relative elevation of the recharge area, shale/sand nature of the layers, etc. Intervening shale layers have generally a higher salinity than the adjacent sand layers resulting in an actual irregular salinity profile as seen on wireline logs. Several basins, especially in the western U.S., show lower TDS at larger depths than usual because of the high elevations of their recharge zones, e.g., in the Sierra Nevada. Other basins, such as the Gulf Coast basin, also show low TDS at large depth, particularly along depositional features such as fluvial channels that happen to line up more or less parallel to the formation dip. However, it does not follow from this observation that the TDS profile in a wellbore mimics that of the surrounding pore space. TDS conditions in a wellbore depend on the nature of the fluids present, number of plugs, number of perforated intervals, the detailed formation pressure profile along but outside of the well, the history of the wellbore, etc.

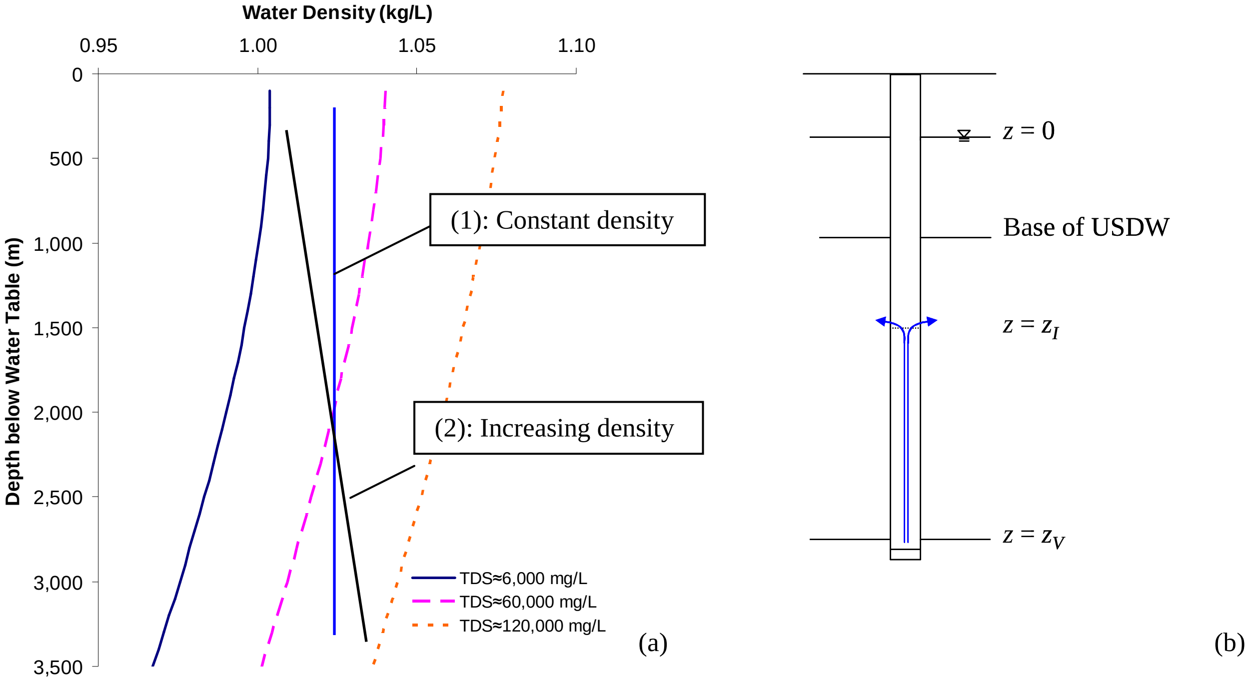

Figure 1. (a) Water density variations with depth at constant salinity; geothermal gradient is 30°C/km; vertical lines represent possible water density profiles in a borehole: case (1) constant density, density increase due to salinity increase is balanced by density decrease due to temperature increase; case (2) increasing density: temperature increase cannot balance faster salinity increase. (b) Schematics of the modeled system

In a system with alternating "shales" (mudstones) and "sands" (sandstones) only sands are contributing fluids to the wellbore producing a smoother salinity profile than in the surrounding formations. The salinity variation can then be assumed to vary linearly with depth (vertical lines of Fig. 1a). However, water density is not only a function of salinity but also a function of temperature and pressure. For a given salinity and under normal temperature and pressure conditions, water density decreases with increasing depth (curved lines of Fig. 1a —using data from Rodgers and Pitzer [3]) because water thermal expansion coefficient has larger effect than water compressibility for all water salinity values in this range of temperature and pressure.

3. Wellbore Brine Migration

An increase in pressure in the injection formation will lead to the migration of saline brine into the wellbore at location z_V in Fig. 1b. If the brine is denser than the borehole fluid it displaces, depending on the pressure change, upward displacement may stop before reaching the bottom of the USDW. Although wellbore and borehole geometry and status span a large set of conditions, bounding cases considered in this analysis consist of (i) an open borehole that instantaneously equilibrates in response to the additional pressure without letting the fluid equilibrate with its surroundings, and (ii) an open borehole in which a slow pressure rise allows the wellbore fluid to thermally equilibrate with its surroundings. In this section, we calculate the extent to which saline water flow will occur upwards along an open borehole as a function of the TDS of the fluid already present within the wellbore. We make the following general assumptions:

- The system is normally pressured, and only the slight change in pressure computed in this paper can be sustainable without endangering the USDW. If the injection formation is below hydrostatic pressure, then a much larger increase of pressure than calculated in this paper could be sustained.

- There is no thief zone between the USDW and the injection formation. Minkoff et al. [4] and Chang et al. [5] showed that thief zones can attenuate significantly well bore pressure and absorb a significant fraction of the material flux. In addition, the saline brine must reach the bottom of the USDW before sustaining flow and contaminating the aquifer; short of reaching it, the system will simply attain a new equilibrium.

- Wellbore fluids are initially in thermal equilibrium with adjacent formation and thus show the same thermal gradient.

- Formations are mostly flat; this assumption is acceptable when considering zone of elevated pressure along strike. It is less appropriate along dip if the calculation in the following sections suggests a large AoR.

3.1. Maximum Pressure Increase before Sustained Flow Occurs

Assuming that the mud/cement plug does not provide a barrier to flow and that there is a continuous pathway from the injection formation to the base of USDW, we analyze how much differential pressure is needed to sustain flow. Hydrostatic pressure $P(z)$ at depth z (vertical axis oriented downwards with $z = 0$ at the water table, $z = z_V$ at top of the injection formation, and $z = z_I$ at some intermediate depth at which brine can flow out of the wellbore (Fig. 1b)) with variable density is:

$$P(z) = \int_0^z \rho(z) g dz \tag{1}$$

An additional pressure at $z = z_V$ will displace the resident fluid from the borehole and substitute the injection formation brine. We assume that the injection brine moves up to a depth of $z = z_I$ (that is, some intermediate depth). We now are interested in the relationship between the additional pressure ΔP at $z = z_V$ and pressure resulting from the wellbore being filled with brine from z_V to z_I. The primary mechanism for the water column to be able to sustain an additional pressure results from the fact that a less dense water is being replaced by a more dense water. We assume there is no change in borehole fluid composition for $z < z_I$:

$$\frac{\Delta P}{g} = \left(\int_{zI}^{zV} \rho(z) dz \right)_{\Delta P} - \left(\int_{zI}^{zV} \rho(z) dz \right)_{ini} \tag{2}$$

where g is the gravitational constant and where the index ΔP represents water density profile after the pressure change in the injection formation has been imposed and the index *ini* represents initial equilibrated conditions before the pressure change. Under the reasonable assumption that water density varies linearly with depth, we can write, using density at z_I as the reference density ρ_I:

$$\rho(z) = \rho_I + \xi (z - z_I) \tag{3a}$$

where ξ is a linear coefficient. This formulation is applied to the initial condition integral but is also valid for the other integral if the need arises:

$$\rho(z) = \rho_{I,\lambda} + \lambda (z - z_I) \tag{3b}$$

where λ is another linear coefficient necessarily different from ξ. The term $\rho_{I,\lambda}$ represents the density at depth z_I with the second formulation, that is after the pressure increase has moved denser brine into the wellbore. Both integrals in Eq. 2 have the same form of solution :

$$\left(\int_{zI}^{zV} \rho(z) dz \right)_{ini} = \left[\frac{\xi}{2} z^2 + (\rho_I - \xi z_I) z \right]_{zI}^{zV} \quad and \quad \left(\int_{zI}^{zV} \rho(z) dz \right)_{\Delta P} = \left[\frac{\lambda}{2} z^2 + (\rho_{I,\lambda} - \lambda z_I) z \right]_{zI}^{zV} \tag{4}$$

The bounding case of an instantaneous pulse (brine from the injection formation will not equilibrate with the borehole surroundings) assumes a constant density, that of the brine in the injection formation:

$$\left(\int_{zI}^{zV} \rho(z) dz \right)_{\Delta P} = \rho_V (z_V - z_I) \tag{5}$$

where ρ_V is the density of the brine invading from the injection formation at temperature and pressure conditions from the injection formation (at $z = z_V$).

$$\frac{\Delta P}{g} = \rho_V (z_V - z_I) - \int_{zI}^{zV} \rho(z) dz \tag{6a}$$

$$\frac{\Delta P}{g} = \rho_V (z_V - z_I) - \left[\frac{\xi}{2} z^2 + (\rho_I - \xi z_I) z \right]_{zI}^{zV} = \rho_V (z_V - z_I) - (z_v - z_I) \left(\frac{\xi}{2} (z_v + z_I) + \rho_I - \xi z_I \right) \tag{6b}$$

$$\frac{\Delta P}{g} = (z_V - z_I)\left(\rho_V - \frac{\xi}{2}(z_v - z_I) - \rho_I\right) \tag{6c}$$

$$\frac{\Delta P}{g} = \frac{\xi}{2}(z_v - z_I)^2 \tag{7}$$

If the change in pressure in the bounding case of Eq. (7) is smaller than the value in Eq. (2), the borehole fluids reach a new equilibrium and the only fluid leaving the borehole and invading the USDW is the volume of water previously in the well bore. This volume is small and presumably will minimally impact the aquifer as it will be quickly diluted).

If the pressure increase can be considered slow enough for the fluid to equilibrate thermally with its surroundings then:

$$\frac{\Delta P}{g} = \left(\int_{zI}^{zV} \rho(z)dz\right)_{\Delta P} - \left(\int_{zI}^{zV} \rho(z)dz\right)_{ini} \tag{8a}$$

$$\frac{\Delta P}{g} = \left[\frac{\lambda}{2}z^2 + (\rho_{I,\lambda} - \lambda\, z_I)z\right]_{zI}^{zV} - \left[\frac{\xi}{2}z^2 + (\rho_I - \xi\, z_I)z\right]_{zI}^{zV} \tag{8b}$$

$$\frac{\Delta P}{g} = \left(\frac{\lambda}{2} - \frac{\xi}{2}\right)(z_V^2 - z_I^2) + (z_v - z_I)\big((\rho_{I,\lambda} - \lambda\, z_I) - (\rho_I - \xi\, z_I)\big) \tag{8c}$$

$$\frac{\Delta P}{g} = (z_v - z_I)\left(\frac{\lambda - \xi}{2}(z_v - z_I) + \rho_{I,\lambda} - \rho_I\right) \tag{9}$$

Equation (9) states that the additional pressure has to be balanced by the increase in density of the water column in the well bore. Not surprisingly, because of the assumption of linear variations, the density difference can be computed from the density values at the midpoint between the top of the injection formation and the base of the USDW before and after action of the pressure pulse. The coefficients ξ and λ depend on the rate of TDS increase with depth and on the geothermal gradient, respectively.

4. Applications to Case Studies

We apply this approach to three cases and compare the results to an analytical formulation of pressure buildup resulting from constant rate injection.

Table 1. Case study parameters

Parameter	California Site	Texas Site 1	Texas Site 2
Top of injection Fm. (m)	2277	2500	2500
Base of USDW (m)	1215	700	700
Injection Fm. TDS (g.L^{-1})	20	60	60
Borehole range of salinity (g.L^{-1})	0.5 - 20	0.5-20	10-20
Density gradient λ at constant TDS (kg.L^{-1}.m^{-1})	-1.16×10^{-5}	-1.10×10^{-5}	-1.10×10^{-5}
Initial density gradient ξ in borehole (kg.L^{-1}.m^{-1})	3.75×10^{-7}	-3.81×10^{-6}	-6.98×10^{-7}
Final density difference at base of USDW (kg.L^{-1})	0.0118	0.0379	0.0322
Maximum admissible pressure (bar)	0.58	5.6	5.15
Distance from injection well (km)	21	1.0	1.4

4.1. California Case Study

We examine a site in the Central Valley of California whose injection depth interval starts at 2277 m and whose injection formation water averages a low TDS of 20,000mg/L (Oldenburg et al. [6]) (Table 1). The base of the USDW is located at a depth of 1215 m above the injection formation. In undisturbed conditions, the slight density gradient is mostly due to salinity variations (ξ = 3.75×10^{-7}) (Fig. 2). We assume that no flow occurs in the wellbore in undisturbed conditions. After action of the pressure increase, the more saline fluid coming from the injection formation in thermal equilibrium with its surroundings but maintains its salinity; geothermal gradient is at the origin of the density gradient (λ = -1.16×10^{-5}). The density difference of the two fluids before and after the pressure change at a depth of z_I is 0.0118 kg/L.

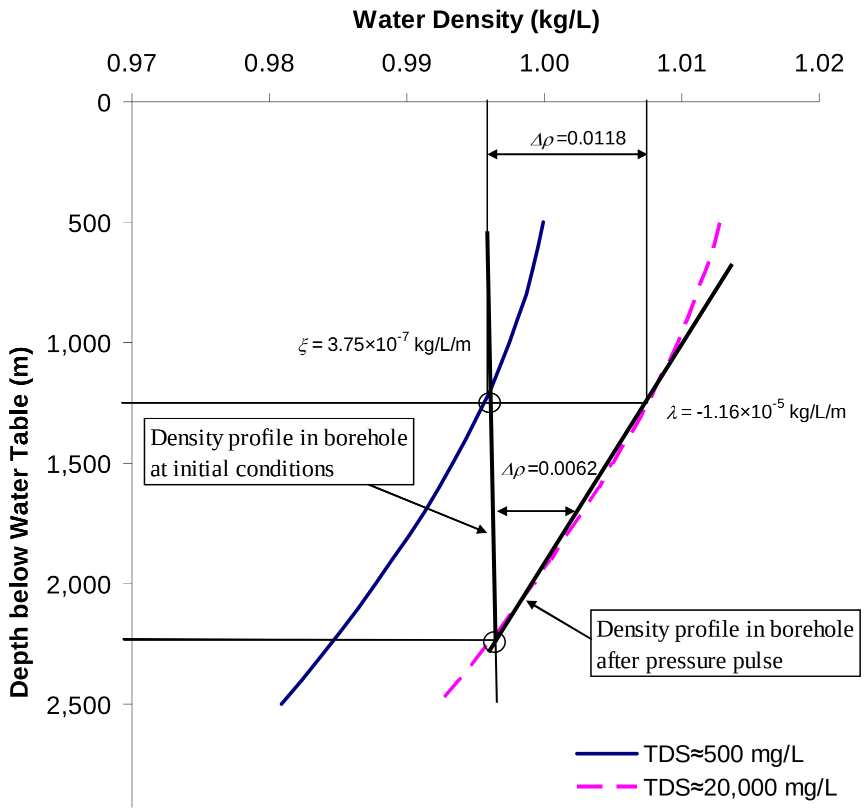

Figure 2. Graphical determination of the maximum allowed excess pressure in the California case study. The colored curves display the density variation of a parcel of water with depth for two values of salinity

We next compute the additional pressure that would allow full replacement of the wellbore initial water with the saline aquifer water but without sustaining flow. Application of Equation *(9)* yields:

$$\frac{\Delta P}{g} = (2277 - 1215)\left(\frac{-1.16\times10^{-5} - 3.75\times10^{-7}}{2}(2277 - 1215) + 0.0118\right) \tag{10}$$

and an admissible additional pressure of 0.58 bars. Pressure increments in the injection formation exceeding this threshold would sustain the column of denser brine in the wellbore up to the base of USDW and thereby lead to contamination.

If we assume that the fluid has no time to equilibrate, Equation *(7)* is used:

$$\frac{\Delta P}{g} = \frac{3.75\times10^{-7}}{2}(2277 - 1215)^2 \tag{11}$$

with an admissible additional pressure of 0.21 bars

4.2. Texas Case Study

A hypothetical site, adapted from Nicot [1] and located in the Wilcox Fm. in the Texas upper Gulf Coast has a 60-g/l TDS injection formation whose top is at a depth of 2500 m. In agreement with the general approach, the generic wellbore is assumed not to communicate with several overlying saline water formations (Carrizo and Yegua Fms.) but only the Gulf Coast aquifers whose bottom is estimated at 700 m. We examine 2 subcases that differ by the nature of the borehole initial conditions: TDS varying from 0.5 mg/L to 20mg/L (Fig. 3) and from 10 g/L to 20 g/L (Fig. 4). This choice emphasizes the points that wellbore density profile is a function of the history of the wellbore and that water density at the top of the injection formation is not necessarily the same as the TDS in the injection formation.

Application of Equation *(9)* yields:

$$\frac{\Delta P}{g} = (2500 - 700)\left(\frac{-1.10\times10^{-5} + 3.81\times10^{-6}}{2}(2500 - 700) + 0.0379\right) \tag{11a}$$

$$\frac{\Delta P}{g} = (2500 - 700)\left(\frac{-1.10\times10^{-5} + 6.98\times10^{-6}}{2}(2500 - 700) + 0.0322\right) \tag{11b}$$

and an admissible additional pressure of 5.6 bars and 5.15 bars in the less saline and more saline initial conditions, respectively. The larger threshold pressures in these subcases, compared to the California case, are the consequence of having much denser brine entering the wellbore.

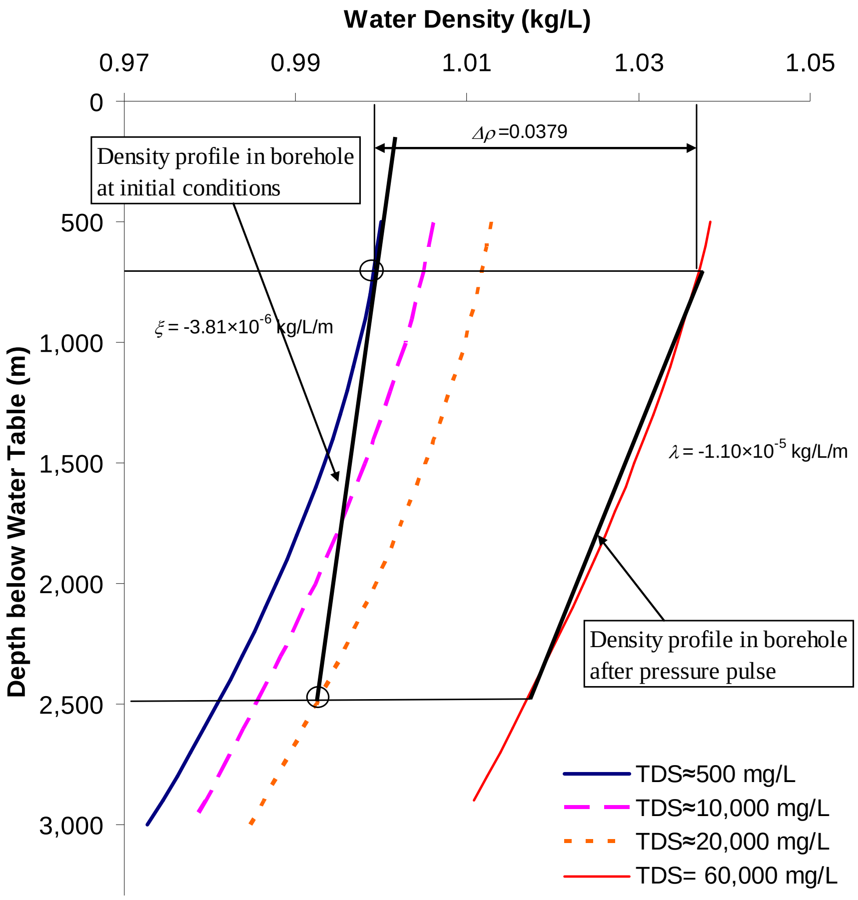

Figure 3. Graphical determination of the maximum allowed excess pressure in the first subcase study (0.5 to 20 g/L TDS variation in the borehole, initially; salinity in injection formation is 60 g/L TDS). The figure also displays the density variation of a parcel of water with depth for several values of salinity

4.3. Comparison to Pressure Signals

Customary pressure computation uses the standard Theis formalism (e.g., Warner and Lehr [7]) assuming an ideal reservoir and with or without the exponential integral. It is also the formulation called for by EPA and some states to compare zone of elevated pressure and AoR. This paper also uses this approach although more accurate pressure samplings would be provided by a multi-phase flow numerical code (e.g., Oruganti and Bryant [8]). For an accurate delineation of the AoR, the user must rely on multi-phase flow numerical modeling for reasons including the fact that compressibility of CO_2 is a function of pressure, introducing a feedback loop in the determination of the pressure field (compressibility of water is fairly constant), difference in viscosity between water and supercritical CO_2 (and thus impacting the conductivity field), and buoyancy effects. To get an understanding of how far from the injection sites the pressure values calculated in the previous sections stand, we use a generic reservoir with the following characteristics: injection of 1.43 million tons of water a year (equivalent on a volume basis to 1 Mt/yr CO_2 with a density of 0.7) for 30 years in a 100 meter-thick formation with porosity of 0.2, permeability of 300 md, compressibility of 6×10^{-5} psi^{-1}, and viscosity of 0.75 cp. This translates into a distance of 21, 1.0, and 1.5 km, respectively, to define the edge of the AoR (again with the paper assumptions, including that of hydrostatic pressure).

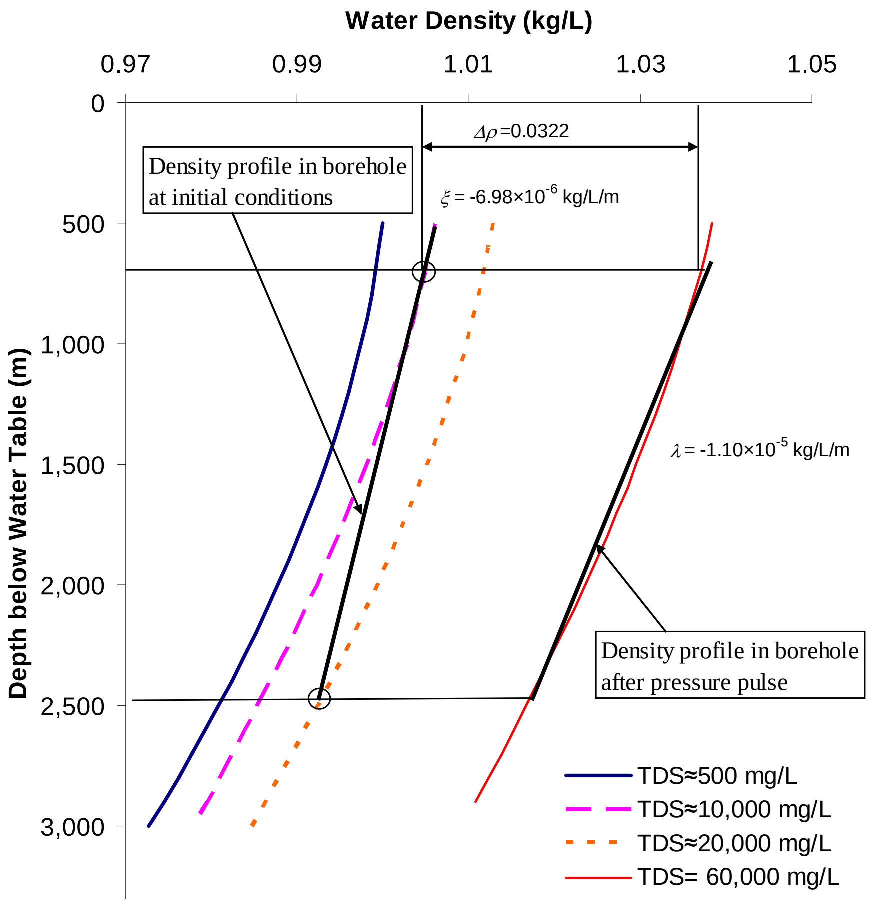

Figure 4. Graphical determination of the maximum allowed excess pressure in the second subcase study (10 to 20 g/L TDS variation in the borehole, initially; salinity in injection formation is 60 g/L TDS). The figure also displays the density variation of a parcel of water with depth for several values of salinity.

4.4. Additional Flow Barriers

The strong possibility of a lower than hydrostatic pressure (deliberately not taken into account in the preceding calculations) will alter the results and will essentially render them moot. Each meter of difference between the injection formation piezometric surface and bottom of the USDW adds ~0.1 bar of admissible pressure increase. However, in sites with little data available, the presumption of hydrostatic pressure profile must be made. Another likely occurrence in most wellbores is the presence of cement plugs and mud-filled sections between them as requested by EPA regulations. Rotary-drilled dry holes without proper plugging records can be assumed to have been left mud-filled because there is no economic incentive to recover the mud (e.g., Johnston and Knape [9]). Gel strength of water-based mud increases indefinitely with time at a fast rate first, and then more and more slowly, but the gel becomes denser with time (filtration loss into adjacent formation). Currently, water-based drilling muds are used from the surface to depths of ~1,500 m, after which depth, oil-based drilling fluids are used.

Mud gel strength typically increases with time and temperature and, until the gel structure is broken, the mud will stay unbroken and unaffected. Displacement pressure PD needed to overcome the gel resistance is given by $PD = a \times S_G \times h/D$ where a is a unit conversion factor, S_G is the gel strength, h is the height of the mud column, and D is the hole diameter (Johnston and Knape [9]). In working operating conditions, mud gel strength is less than 1 lb/100 ft^2, but once settled, it can increase to values as high as 100 lb/100 ft^2. Johnston and Knape [9] suggested that a minimum value of 25 lb/100 ft^2 be used for abandoned wells. This value corresponds for a ~1,500 m mud column in a 15-inch hole to an extra pressure >7 bars (in addition to the column weight) needed to move the column. This value is not very large but can be significant for small-scale injection and to limit the size of the AoR.

5. Conclusions

Owing simply to density differences due to temperature and salinity subsurface variations, a wellbore with a continuous open pathway between the injection formation and the bottom of the USDW will not necessarily lead to contamination of USDW when CO_2 is injected. We show representative examples in which a pressure increment of a fraction of a bar up to several bars can be sustained without flow, depending on subsurface parameters and under the assumption of initial hydrostatic pressure profile. The fact that a threshold pressure exists for displacing brine along a long vertical path, in which density variations are certain, has important implications for risk assessment.

Injection of 1 million tons a year for 30 years translated into an AoR larger than 20 km in a less favorable case (California) with a TDS lower than most for the injection depth. The other case (Texas) resulted in an AoR between 1 and 2 km. However, AoRs were computed approximately using the standard EPA approach not using a multiphase flow numerical model. In addition, results are sensitive to the form of the Equation of State (EOS) of water used in the calculations. We investigated cases in which the formation brine is allowed to reach the bottom of the USDW (but no farther). A similar approach could be used to estimate additional pressure than would raise the formation brine to some distance below the bottom of the USDW.

Acknowledgments

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