Seismic Modeling of Acid-Gas Injection in a Deep Saline Reservoir

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Summary

A case is studied of non-aqueous acid gas injection into a saline dolostone reservoir. The feasibility of monitoring is judged by the sensitivity of traveltimes and reflection coefficients to fluid substitution. Using acid-gas properties from the Peng-Robinson equation of state and fluid substitution effects from Gassmann's equations, the traveltime difference is seen to be on the order of a quarter millisecond for each 10 m thickness of the acid-gas plume for average dolostone properties, and up to a half millisecond for softer dolostones. Minor changes in reflection coefficient are also observed, but full analysis with well logs would be required for a useful assessment of the AVO effect.

Introduction

Carbon dioxide (CO_2) and hydrogen sulfide (H_2S) are common byproducts of the energy industry. A course of remediation which is being explored is to sequester them in subsurface reservoirs. Deep saline reservoirs are one attractive target. Acid gas injection is becoming a method of choice (as a replacement for flaring) at smaller gas wells where it is not economical to build traditional facilities for scrubbing. For such injection programs to work it would be desirable to track the progress of the injection plume via seismic monitoring. To study the feasibility of monitoring, one should first carry out modeling studies of fluid substitution, to gain insight into the ability of the seismic method to distinguish pre- and post-injection states of the reservoir medium. The purpose of this study is to carry out fluid substitution calculations for the modeling of an injection process.

Problem Statement

Given information on a deep saline reservoir, and on an injected acid gas, we wish to carry out fluid substitution calculations in order to assess whether surface seismic may be feasibly used to monitor progress of the injection plume.

The following information is given: For the reservoir we know temperature (40°C), pressure (9465 kPa), porosity (0.10), and general lithology (dolostone). We also know the salinity of the pre-existing brine (120,000 ppm). We do not know exact thickness and do not possess well logs. For the acid gas we know the mole fraction of the acid components (xCO2 = 0.745, xH2S = 0.193, xH2O = 0).

The above information represents one case of interest that will be used for concreteness; however this report is more concerned with developing methodology that may be applied or adapted to a variety of acid-gas injection scenarios.

Proposed Method

Given the information above, the general approach to this problem will consist of the following steps:

1) Determine acoustic properties (at reservoir temperature and pressure) of relevant fluids. 2) Obtain elastic properties of the reservoir rock for some reference saturated state, and the elastic properties of the mineral(s) comprising it. 3) Determine the change in reservoir elastic properties due to fluid substitution via Gassmann's equation.

<u>Determining fluid properties</u>: Three fluids are of interest in this case, water, brine and non-aqueous acid gas. The acoustic properties of water and brine (i.e. density and P-wave velocity) are readily determined from available empirical relations, if the salinity of the brine is known and is due to the species NaCl. These expressions are available, for instance, in Batzle and Wang (1992) or Mavko et al. (1998).

Acid gas, while a key player in refining operations, has not been much on the exploration or development radar before now. Thus its acoustic properties have not been well-investigated. A variety of approaches are possible for calculating properties of acid gas. We follow the recommendation of Carroll (2002) who has shown that the Peng-Robinson equation of state (Peng and Robinson, 1976) provides an adequate description of non-aqueous acid gas.

<u>Determining reservoir rock properties</u>: Normally the elastic properties of a reservoir are estimated from well-log data, especially if P-wave and S-wave sonic logs are available. This section addresses the case when such data is not available. In this case we can make use of literature data to estimate reasonable values for the elastic properties of water-saturated dolomite of known porosity.

Our source for literature data is Mavko et al. (1998), p. 292-293. Graphs are presented there for correlation of various quantities, along with best-fit correlations. The three results of interest to us are

$$V_P \text{ [km/s]} = 6.6067 - 9.3808\,\phi \tag{1}$$

$$V_S \text{ [km/s]} = 3.5817 - 4.7194\,\phi \tag{2}$$

$$\rho \text{ [g/cm}^3\text{]} = 1.8439 + 0.13786\, V_P \text{ [km/s]} \tag{3}$$

Thus for a given porosity one can estimate three typical elastic properties for water-saturated dolomite. From the scatter of data in the graphs, one can also visually estimate an uncertainty in each of these values. Thus, for instance, V_P of water-saturated dolostone is likely to be in the range 5.2 – 6.2 km/s, with a most probable value of 5.7 km/s.

We also require elastic properties (or at least bulk modulus and density) of the mineral dolomite, $CaMg(CO_3)_2$, of which the rock matrix is composed. Again we turn to data from Mavko et al. (1998, p. 308) which lists three values for these properties. We have used the average of all listed values for our calculation.

<u>Fluid substitution calculations</u>: The most common (though not the only) approach to performing fluid substitution calculations is to use the Gassmann equation (Mavko et al., 1998):

Once one has all elastic properties for the brine and acid-gas saturated states, one can obtain velocities as well, and then one can perform seismic modeling to assess whether seismic monitoring will be able to follow progress of the injection plume.

Fluid Substitution Results

We have used equations 1-3 and the data above to calculate elastic properties after fluid substitution. As the composition of the acid gas is not fully defined, it is assumed that the remaining 6.2% consists of methane gas. Application of standard Gassmann substitution beginning with water-saturated rock yields (ρ,V_P,V_S) equal to (2.6 g/cm^3, 5.8 km/s, 3.1 km/s) for the brine-saturated rock and (2.5 g/cm^3, 5.4 km/s, 3.1 km/s) for the acid-gas-saturated rock.

Modeling Results

Monitoring fluid substitution in the subsurface can be accomplished by a variety of methods, depending on what properties are most sensitive to a change in fluid. Two characteristics of seismic data that can be influenced are traveltime through the reservoir and amplitude variation with offset (AVO) at the top or bottom of the reservoir.

<u>Traveltime calculations:</u> The difference in two-way traveltime for a P-wave traveling vertically through a reservoir containing either brine or acid gas is given by

$$\Delta T = 2d\left(\frac{1}{V_P(\text{acid gas})} - \frac{1}{V_P(\text{brine})}\right), \qquad (4)$$

where d is the thickness of the reservoir. Using data above we find that there is a 0.26 ms increase in two-way traveltime after fluid substitution, for each 10 m thickness of the reservoir.

Because precise information is not available on the elastic properties of the reservoir, it is also of interest to see how this traveltime difference estimate varies with properties of the reservoir. To accomplish this the calculations for fluid substitution and for equation 4 were re-executed several times for various values of V_P from 5.2 to 6.2 km/s. The results are shown in Figure 1.

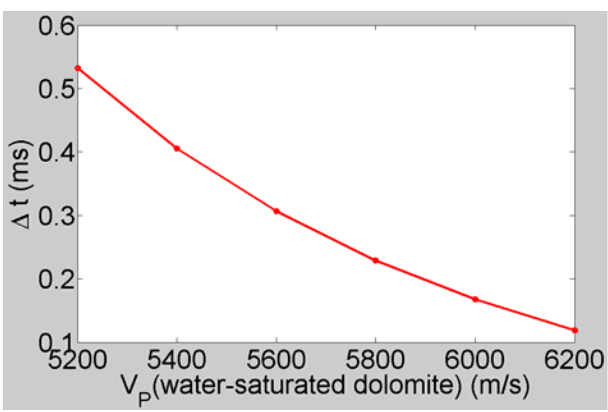

Figure 1: The effect of reservoir rock V_P on two-way traveltime differences resulting from fluid substitution.

For the softer end of the range, traveltime differences are about 0.5 ms per 10 m thickness of the reservoir. This is a measureable amount and suggests that seismic monitoring may be feasible. Of course if V_P is at the lower end of its range, then V_S and ρ, which are positively correlated with V_P, are likely at the lower end of their ranges as well. However, if we recalculate Figure 1, adjusting V_S and ρ in synchrony with V_P, then a similar graph is obtained, but with Δt ranging from about 0.17 to 0.47 ms, rather than from 0.12 to 0.53 ms.

AVO calculations: The reflectivity at a boundary of the reservoir is influenced not only by the elastic properties of the reservoir, but also the properties of the bounding media. This information can be obtained from well logs, but in the absence of such, we will assume that the surrounding media are composed of the same rock as the reservoir, but simply contain brine rather than acid gas. Again using data above we can calculate the plane-wave Zoeppritz coefficients, with results displayed in Figure 2a.

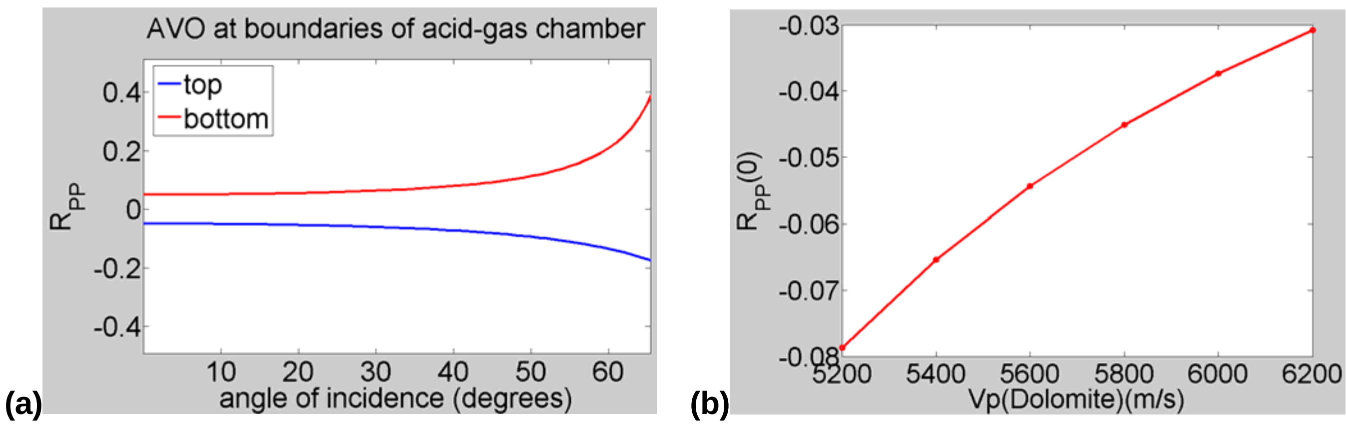

Figure 2: (a) Reflection coefficient curves defining RPP(θ) at the top and bottom of an acid gas layer. The rock matrix is assumed to be constant across the interfaces, with brine saturation above and below the reservoir. (b) The effect of reservoir rock V_P on vertical reflectivity [$R_{PP}(0)$] at the top of the injection chamber, given the same assumptions as in Figure 1.

The AVO trends shown in Figure 2a do not suggest a very strong response, but more complete modeling with well logs would be required before drawing any final conclusions on the use of AVO for seismic monitoring of this injection.

For completeness, in analogy to Figure 1, we can consider how varying V_P affects $R_{PP}(0)$, and these results are shown in Figure 2b. Again, for softer reservoirs, the picture is improved, if only moderately.

Discussion and Conclusions

We have performed calculations relevant to the fluid substitution problem for acid gas injection into a deep saline reservoir. Implicit in this Gassmann approach are at least assumptions: 1) The injected acid gas fully displaces the native brine, rather than mixing with it. 2) The injected acid gas does not react with the dolomite reservoir rock to change its elastic properties. These are likely reasonable assumptions on the timescale of the injection program, but would need to be revisited to model long-term storage. Two other assumptions are made in this studies: 1) In the absence of well logs, the properties of the dolomite matrix are estimated from a range of typical values found in the literature. 2) Methane is assumed to account for the fraction of acid gas which is not CO_2 or H_2S.

Based on the above assumptions, we have shown that, for every ten meters thickness in the injection chamber, a vertical seismic signal will likely have a 0.26 ms longer two-way traveltime than through the brine-saturated reservoir. This is based on average properties of dolostone. For dolostone on the softer end of the spectrum, 0.5 ms change is more likely. Changes in reflection amplitudes resulting from fluid substitution do not appear as promising for injection monitoring, but well-log based analysis would be necessary to draw firm concluisions.

References

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