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PS Model of CO_2 Leakage Rates Along a Wellbore*

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Abstract

Large-scale geological storage of CO_2 is likely to bring CO_2 plumes into contact with a large number of existing wellbores. Wellbores that no longer provide proper zonal isolation establish a primary pathway for a buoyant CO_2-rich phase to escape from the intended storage formation. The hazard of CO_2 leakage along these pathways will depend on the rate of leakage. Thus a useful component of a risk assessment framework is a model that will permit estimation of CO_2 leakage rates.

Predicting the flux of CO_2 along a leaking wellbore requires a model of fluid properties and of transport along the leakage pathway. Leakage rates through the cement matrix are likely to be smaller than naturally occurring background fluxes, because the permeability of intact cement is of order a few microdarcies. Leakage large enough to be a concern is most likely to occur along a defect (fracture, microannulus, gas channel) in the steel/cement/earth system. This type of discrete leakage pathway has a specific geometry. Its hydraulic conductivity is therefore sensitive to the effective stress on the pathway, that is, the confining earth stresses less the fluid pressure within the pathway. The leakage pathway is likely to traverse a material such as cement that reacts chemically with CO_2 or CO_2-saturated brine. The reaction can alter the mechanical properties of the material and specific volume of the surface of the material. Consequently the hydraulic conductivity of the pathway can change as CO_2 migrates through it. This coupling between geochemistry and geomechanics is much stronger for discrete pathways than for flow through a matrix. In this work, we lay part of the foundation for a model of the coupled phenomena by examining leakage rates of natural gas production wells, then extending the model to the case of leaking supercritical CO_2.

Leakage Model

Wells that exhibit sustained casing pressure (SCP) are a good analogue of one situation in which stored CO_2 could leak along a wellbore. In particular, the geometry of the leakage path is likely to be similar in both cases. We have implemented a SCP model described in the literature (Huerta, 2009). Applying this model to field observations of pressure buildup (pressure vs. time) yields an estimate of the depth of the leakage source and the effective permeability of the leakage pathway (Figure 1). The latter value can be converted into equivalent geometries of discrete pathways, e.g. the average aperture of a microannulus.
We extend the SCP model to account for the situation in which the leakage source is in communication with a gas reservoir whose pressure is declining due to production. This will cause the driving force for leakage to decrease (Figure 2). This feature is important for SCP wells with long buildup periods. A similar situation can arise in CO_2 leakage during the post-injection period, as pressure built up during injection dissipates.

For leakage paths traversing a sufficiently long vertical distance, the hydrostatic pressure of the column of gas within the path makes a non-negligible contribution to the flow potential. Thus we have further extended the SCP model to account for the gas gravity. For typical SCP wells the correction is small, resulting in permeability estimates within 5% of those from the uncorrected model. This feature is considerably more influential when supercritical CO_2 (density two thirds that of brine) is the migrating fluid. The difference could be 55% for a long column of CO_2 in an example we describe later.

Application to Field Data

The application of the SCP model to field data is an inverse problem. The unknowns are usually the depth corresponding to the leak source and the effective permeability of the leakage path. For many wells, the top of cement in the annulus is not known, and thus the vertical length of the mud column remaining in the annulus is also unknown. It is useful to automate the process of estimating these parameters. We report upon a more robust algorithm to obtain the best fit. The algorithm automates the parameter estimation so that reproducible results are obtained for different users. It also streamlines the process of characterizing effective permeability of a large set of SCP wells. Furthermore it allows weighted optimization to account for asymptotic pressure which is often observed in the field (Figure 3).

CO_2 Leakage Pathway

Finally we describe a model for flow of CO_2 along a discrete pathway (Figure 4). The CO_2 leakage pathway is in two parts. The deeper part is a defect in the wellbore, like those in a well exhibiting SCP. The upper end of the defect intersects the second part of the pathway, which is simply a water saturated porous medium. In both parts of the pathway we assume that only CO_2 is flowing, and we do not account for the transient period of two-phase flow as CO_2 establishes a steady saturation in the pathway. The cement column should be described as a discrete pathway due to the CO_2 properties variation within the column; in this work we illustrate a simpler version that treats the pathway as an equivalent Darcy continuum. The water saturated porous medium is assumed to have no resistance to flow and a hydrostatic pressure gradient is imposed along the column. Its top is and open boundary to the atmosphere. To obtain worst-case estimates of flux, we assume a continuous pathway of constant aperture terminating in an unconfined (constant pressure) exit, and a constant pressure at the leakage source. Geochemical/geomechanical coupling is neglected, so that the hydraulic conductivity of the leakage pathway does not change with time. The properties of CO_2 vary along the pathway because both pressure and temperature vary. We use the Peng-Robinson equation of state and assume an imposed temperature variation (usually geothermal gradient). Viscosity data are interpolated from National Institute of Standards and Technology.

Example

Consider an example of SCP recorded in an offshore well (Figure 5). The well is assumed to have a 4000 ft cement column and 800 ft mud column, for which data we estimate the effective permeability to be 1.4 μD. Assume CO_2 is leaking from the same depth along the same path through the cement, but then rises through water-saturated sand that offers negligible resistance to CO_2 flow. Assume further that the CO_2 is rising only by buoyancy, i.e. that the pressure at the leakage source point is hydrostatic. The temperature profile plotted in (Figure 6) is imposed; the other profiles of pressure, density and viscosity are computed. CO_2 density increases with depth and it reaches supercritical status below depth 2500 ft through this leakage path. We calculate the steady CO_2 leakage rate to be 0.08 mg/m^2/s, equivalent to 2.4 kg/m^2/y. For comparison Allis (2005) showed that CO_2 background flux could go up to 0.1-1.4 mg/m^2/s, and high flux such as in Crystal Geyser could be 27 mg/m^2/s. We conclude that CO_2 flux is below background along leakage path like one in this offshore well.

It is instructive to consider variations on this situation. For example, suppose the leakage happens during injection, so that the CO_2 pressure at the leakage source is 500 psi greater than hydrostatic. The CO_2 leakage rate in this case is 0.1 mg/m^2/s, which is 25% higher than that in the base case. Suppose now that the effective permeability of the leakage path is increased to 1.4 mD (100 times the base case). The CO_2 leakage rate increases in proportion, to 8 mg/m^2/s. We conclude that the leakage rate increases linearly with the effective permeability, despite the nonlinearity of the CO_2 density profile. This leakage rate would be comparable to the natural leak at Crystal Geyser. Finally we consider a case with a longer mud column (2000 ft), and a correspondingly shorter cement pathway. The effective permeability is estimated to be 8.6 μD from the SCP data. The corresponding CO_2 leakage rate is 0.41 mg/m^2/s, five times the base case. If we neglect the hydrostatic pressure of CO_2 in the last case, the leakage rate would be 0.64 mg/m^2/s, which results in a 55% error.

Conclusions

The CO_2 leakage model allows estimating leakage rates along a wellbore provided the information about the depth of leak and effective permeability from the SCP model. It forms the basis for incorporating geochemical/geomechanical coupling. Constitutive relationships for this coupling are being developed in an accompanying set of laboratory experiments. Extended to more SCP wells, this approach can provide a probabilistic distribution of leakage rates given regional and well parameters. For CO_2 sequestration purposes this provides a tool to assess the risk of carbon dioxide escape along leaky wells, which is necessary for site selection, permitting, and properly crediting sequestration operations.

References

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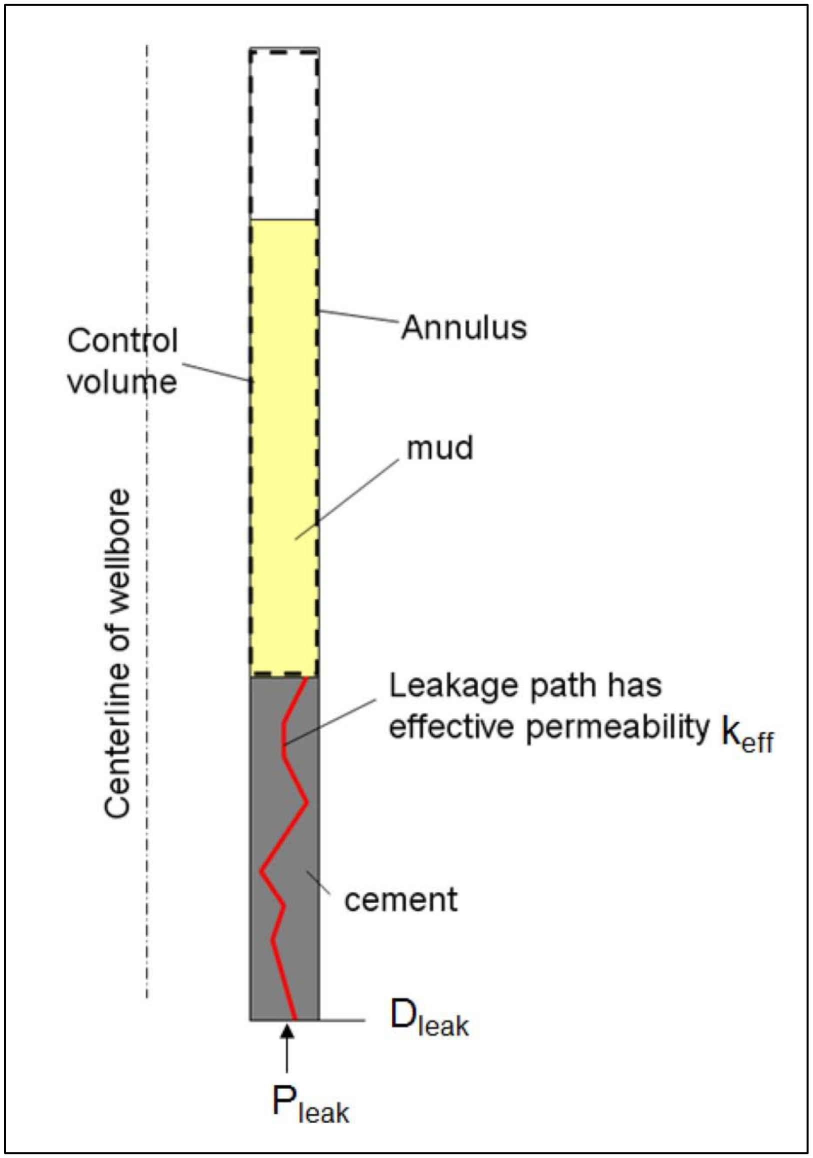

Fig. 1—SCP model has two primary variables: effective permeability of the leakage path and the leakage depth.

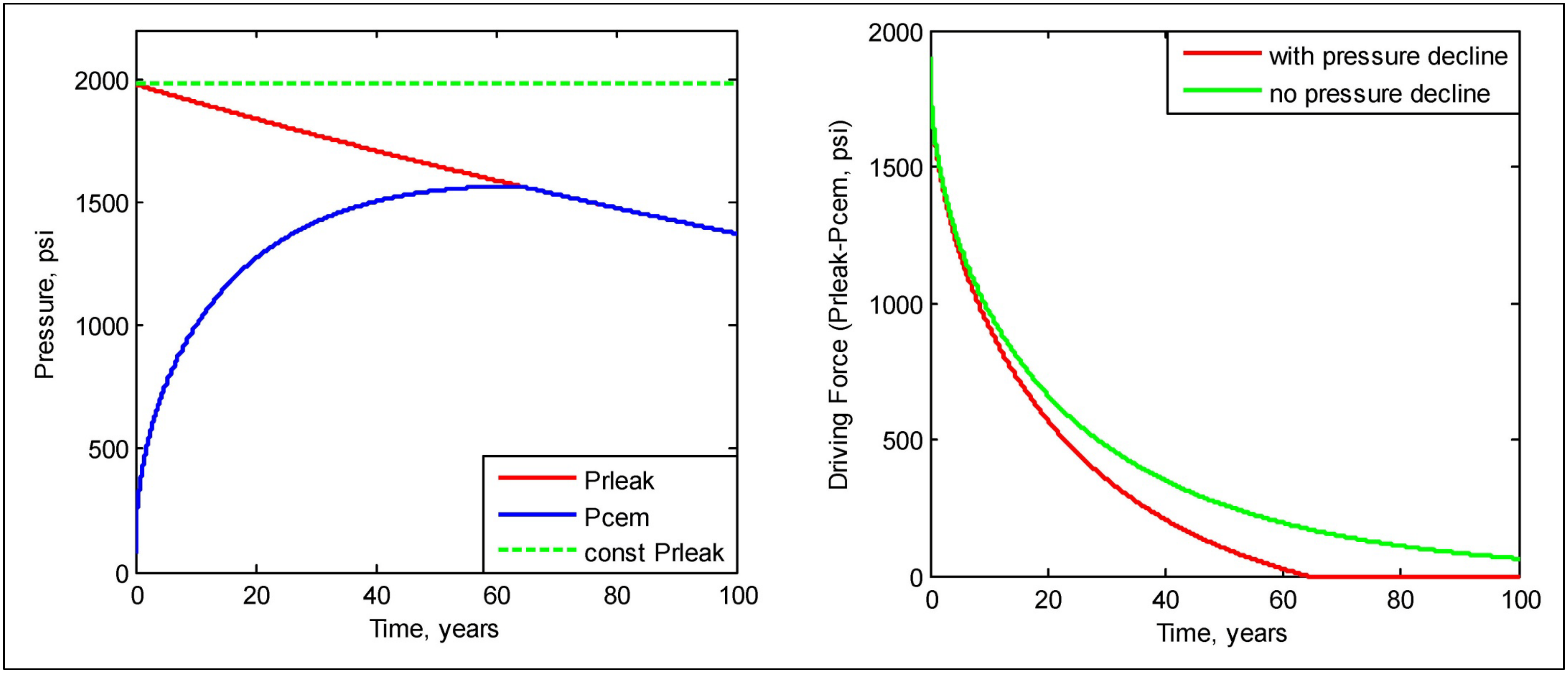

Fig. 2—Formation pressure decline with time (left). Driving force of leakage decreases with declining formation pressure (right).

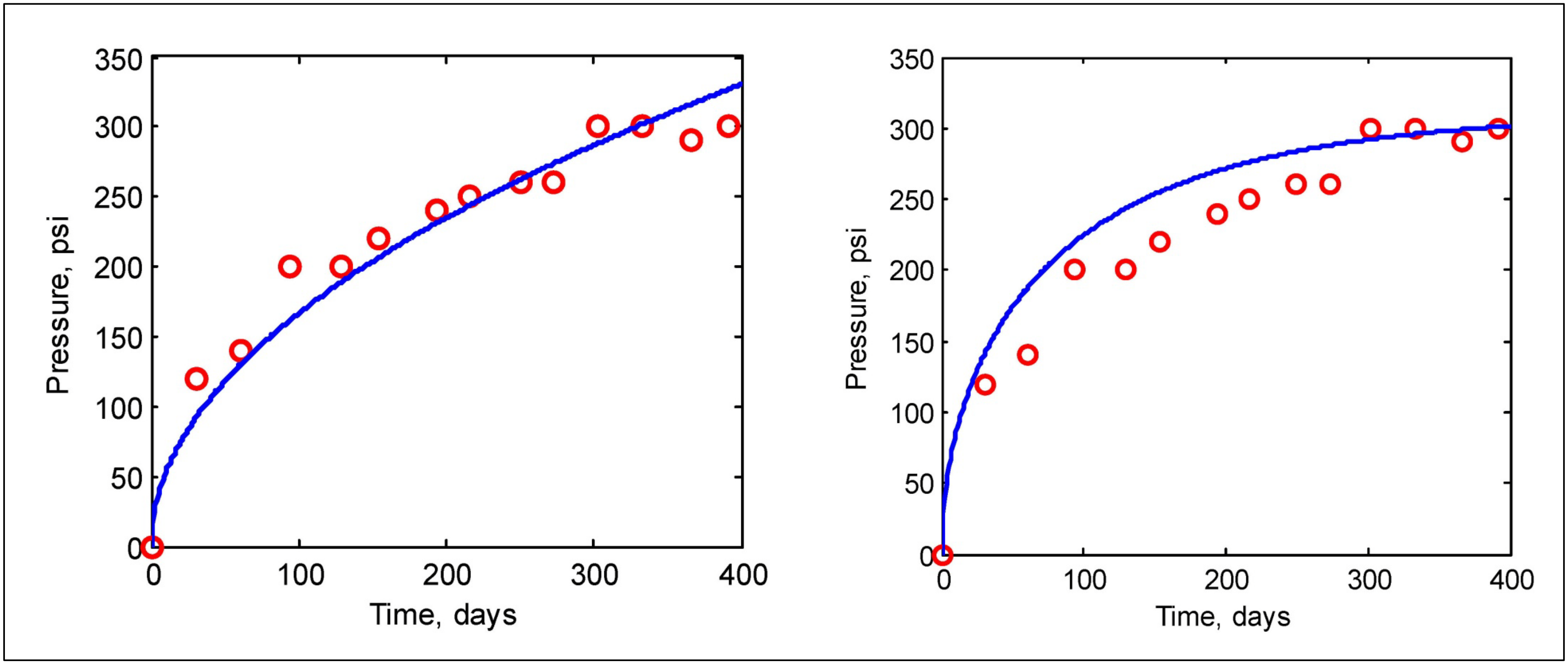

Fig. 3—Comparison of non-weighted optimization (left) and weighted optimization (right).

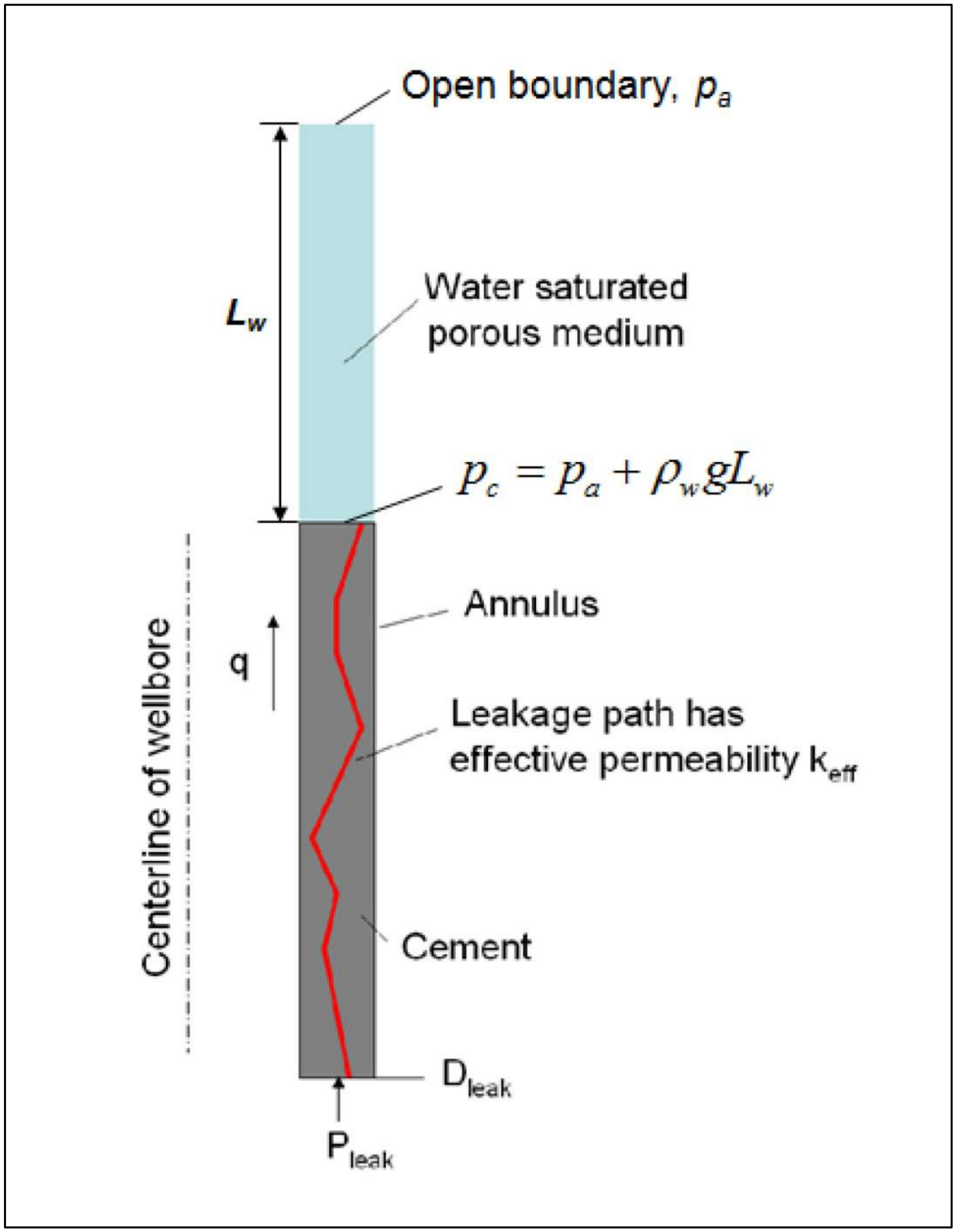

Fig. 4—CO_2 leakage pathway.

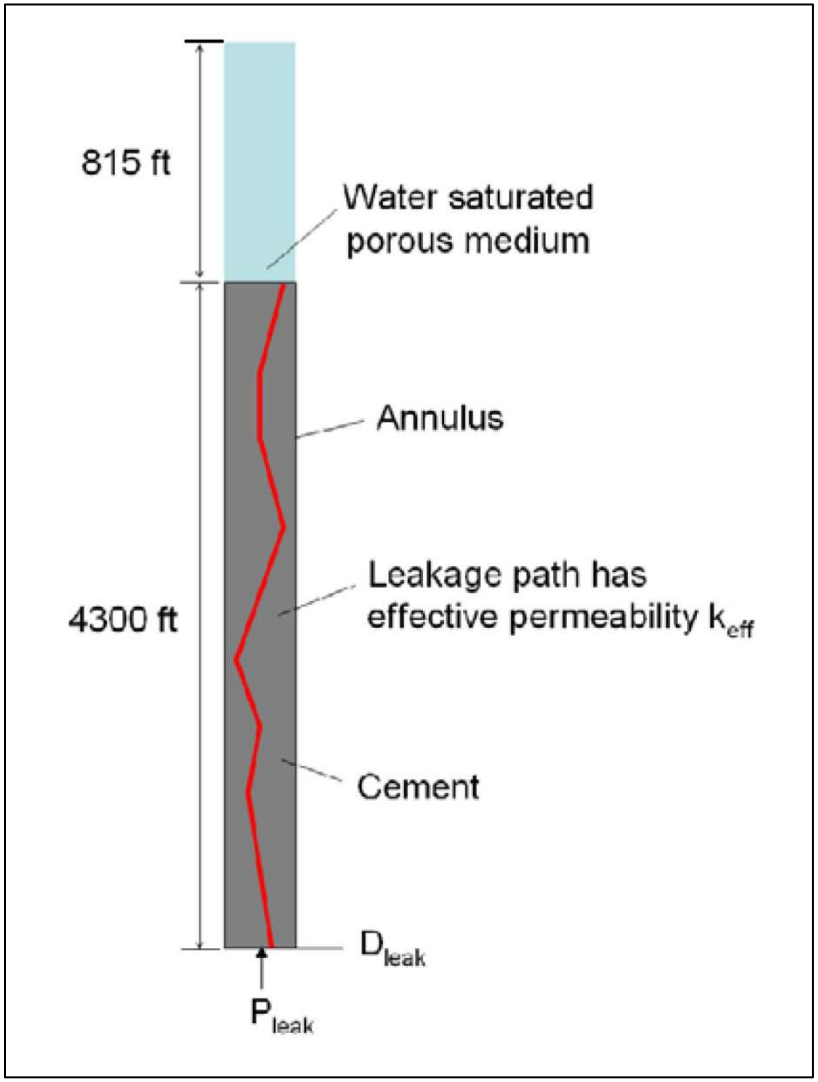

Fig. 5—CO_2 leakage pathway through an offshore well.

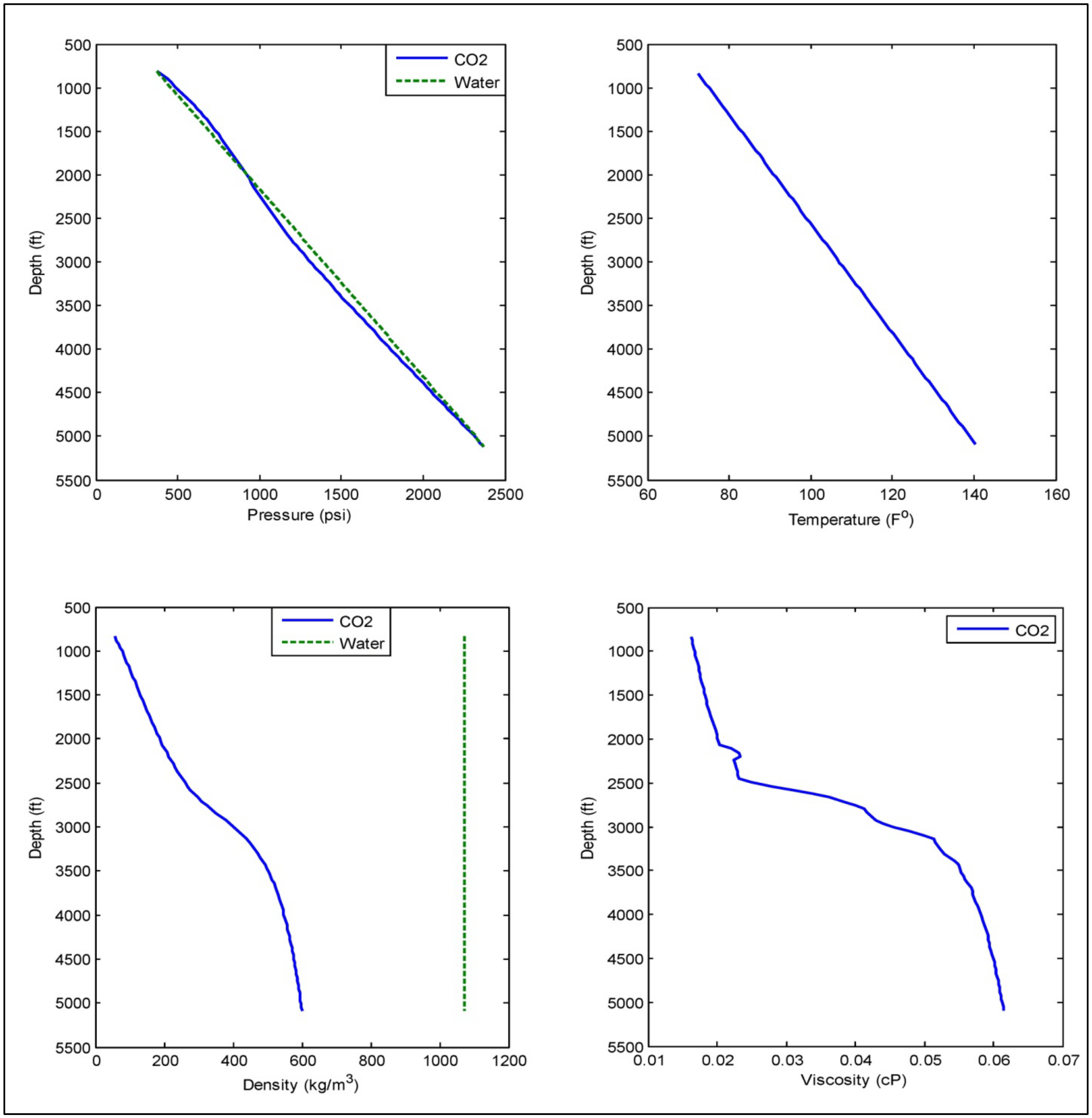

Fig. 6—CO_2 property profiles: pressure (upper left), temperature (upper right), density (lower left) and viscosity (lower right).