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Technical Conference Paper

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Abstract

The flow rates through leaky wellbores associated with hydrocarbon storage facilities, which can result in pressure buildup in the cemented annulus at the surface, depend on the permeabilities of the leakage pathways, including cement fractures and microannuli. Similar to rock fractures, the permeabilities of these flow paths are expected to be a function of the external stresses acting on the fracture and the fluid pressures within the fracture. To determine how fractures respond to changes in confining stress and fluid pressures in a wellbore annulus comprised of fractured cement, fluid (nitrogen and silicone oil) flow tests were performed on fractured wellbore cement samples. The tests were conducted under a wide range of confining stresses and pore pressures, representing the various hydrostatic and fluid (gas and oil) pressures acting on the cement casing. Test results were corrected for non-linear (i.e., visco-inertial) flow as necessary and interpreted in terms of permeability and hydraulic aperture of the fractures. A strong correlation of increasing permeability with an increasing fluid (pore) pressure was found for both oil and gas flow. Results confirm the hypothesis that elevated fluid pressure props fractures open and significantly increase their permeability. The increased permeability, in turn, will result in increased flow (leakage) rates through the wellbore. The experimental results were incorporated into a numerical model that estimates the wellhead pressure response for a wellbore system with a thoroughgoing annular cement fracture. Results from the numerical simulations show that the wellhead response is substantially affected by the fluid pressure in the fracture system. Further, gas flow at the wellhead can be strongly affected by visco-inertial flow.

Key words: Wellbore leakage, Cement fracture, Fracture permeability, Pore pressure, Visco-inertial flow

1- Introduction

Leakage through wellbores is of concern in underground storage facilities for natural gas and hydrocarbons. Leaky wellbores have been identified as a fundamental risk for product loss, as well as conduits for contamination of groundwater resources (Vidic et al., 2013; Ingraffea, 2014; Jackson, 2014). Gas reaching the surface through leaky wellbores is a significant health and safety risk as it may produce exposure to hazardous substances and/or explosions and fires (Gasda et al., 2004; Miyazaki, 2009; Bielicki et al., 2014). The cement sheath behind the wellbore casing is designed to support and protect the casing, seal the annular space between the casing and host rock, and prevent communication of fluids within the annular space. However, the cemented annulus can leak as indicated by pressure build-up at the surface if the wellhead is closed, or surface casing vent flow if the wellhead is open (Checkai et al., 2013). Fractures and microfractures in the cemented annulus are considered as the major leak path for storage facilities in salt formations (Berest et al., 2007). Wellbore cement fractures may be caused by a range of factors including poor cementing job, salt creep adjacent to the wellbore, cavern deformations, and stresses from the temperature and pressure changes within the casing (Gomez et al., 2017; Brett et al., 2017; Tavassoli et al., 2018).

Understanding the nature of flow within the leaky wellbore system is critical to characterize the leakage flow paths, avoid operations that may exacerbate the leakage, support risk assessments of leaky wellbores, and design remedial efforts if necessary. Because cement fractures are a likely flow path through a leaky cemented annulus, it is important to understand how the fractures may respond to changing conditions including the stresses acting on the fractures and the pore pressures within the fractures. In particular, we are interested in the potential for pore pressure to prop open fractures and increase the fracture permeability, and the resultant wellbore leakage. In the study reported here, we have measured the effect of confining stress and pore pressure on the permeability of wellbore cement fractures under a wide range of confining stresses and pore pressures. Findings of the experimental work were applied to a numerical model that estimates the wellhead pressure response for fluid through a wellbore system with annular cement fractures assuming both viscous and visco-inertial flow regimes.

2-Materials and methods

2-1- Sample preparation

Two cylindrical cement samples (A and B) were cast with nominal diameter of 76 mm (3 in) and length of 152 mm (6 in). The cement paste was composed of Type G Portland cement (also referred to as oil well cement) and the standard mix design in accordance with ASTM C305-14 (Table 1).

Table 1. Mix proportions of cement samples

Cement (kg/m^3)	Silica fume (kg/m^3)	Water (l/m^3)	Plasticizer (l/m^3)
1658.6	165.9	547.4	10.4

After the initial setting for about 24 hours, the specimens were cured in a heated water bath for seven days and stored in a curing room before conducting the tests. Fractures were created in the samples by splitting them longitudinally using the Brazilian tensile test method. A semi-circular, perforated steel sheet or shim was placed on the opposite ends of each half of the cement sample to create an offset of the fracture surfaces and prevent perfect mating of fracture surfaces under confining stress. Finally, samples were cast in a low-modulus molding epoxy to produce the necessary diameter of 101.6 mm (4 in) to fit in the testing apparatus.

2-2- Experimental system

A general overview of the experimental system is shown in Figure 1. The fractured cement samples were placed in a pressure vessel and subjected to hydrostatic stress conditions using uniform hydraulic pressure behind a core holder sleeve which is integrated into the pressure vessel. The applied confining stresses correspond to the expected geostatic stress at a depth of about 700 m (2300 ft) and shallower, following both loading and unloading stress paths. The permeameter system allows simultaneous application of confining stress and pore (fluid) pressure. In order to ensure the equilibrium of confining stress after each change, the stress was held static for more than 12 hours before conducting the gas and oil flow tests. At each confining stress, a series of gas and oil flow measurements were made using a range of pressure gradients across the specimens. The applied pore pressures were in the range of 5%-80% of the confining stress. For some tests, the downstream line was vented to the atmosphere and for others a backpressure regulator was used to impose an outlet pressure greater than the atmospheric. The inlet, outlet and differential pressures were recorded using pressure transducers with an accuracy of 1% of full scale. The fluid flow rates were measured using rotameters with different ranges connected to the outlet of the specimen (2% of total flow range accuracy).

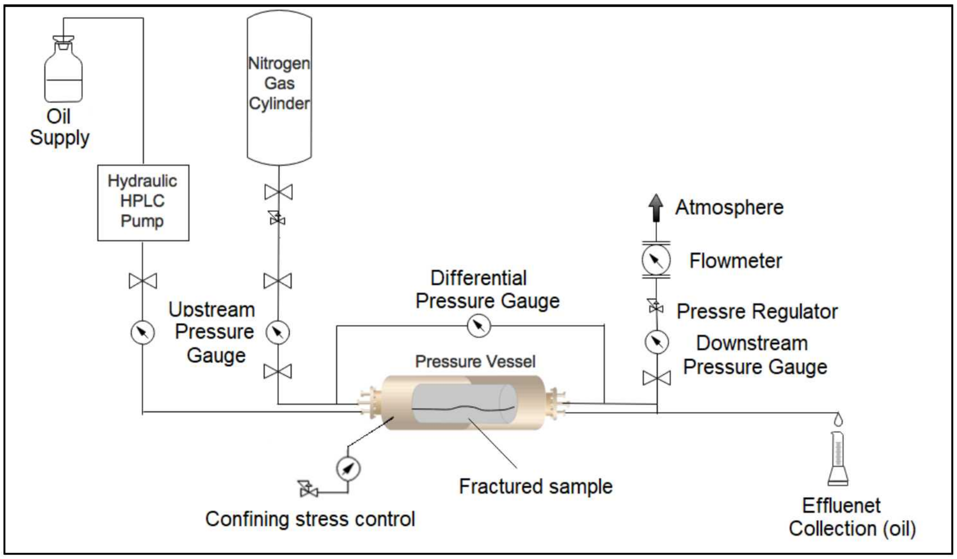

Figure 1. Schematic of the flow test configuration

2-3- Permeability measurements

At each combination of confining stress and pore pressure, the measured flowrates and pressure gradient set were translated into the permeability of cement fracture using the Forchheimer equation (Forchheimer,1901) which includes both viscous (Darcy) and inertial (non-linear) flow terms (Equation 1).

$$-\nabla P = aQ + bQ^2 \qquad (1)$$

$$a = \frac{\mu}{A_f k_f}$$

$$b = \frac{\beta \rho}{{A_f}^2}$$

where ∇P is the pressure gradient in direction of the flow, Q is the volumetric flow rate, A_f is the cross-sectional area of the fracture, μ is the dynamic viscosity of the fluid, k_f is the fracture permeability, β is the non-Darcy coefficient and a and b are the energy losses due to viscous and inertial dissipation mechanisms, respectively. Equation (1) is a general description of flow which reduces to Darcy's law (viscous flow) at flow rates that are low enough so that inertial effects become negligible. In order to apply Equation (1), the inertial coefficient (b) must be known in addition to the fracture permeability.

Since the specimens with fractures are expected to yield permeability values more than 3 orders of magnitude greater than intact cement specimens (Anwar et al., 2019) under comparable conditions, and assuming that flow occurs only through the fracture, the calculated fracture permeability can be interpreted as a hydraulic aperture (h) using the so-called cubic law (Witherspoon et al., 1980):

$$h^3 = \frac{12kA}{w} \tag{2}$$

where w is the width, and h is the hydraulic aperture of the cement fracture.

3- Experimental test results

The results are presented to separately highlight the effect of confining stress and pore pressure on the hydraulic aperture of the wellbore cement fractures. All test results were corrected for non-linear (i.e., visco-inertial) flow as necessary and interpreted in terms of hydraulic aperture of the fractures. The main question these tests seek to address is whether fractured cement permeability/hydraulic aperture is constant, or is it affected by the state of stress and pressure changes imposed on the wellbore cement sheath.

3-1- Effect of confining stress

Variations of the cement fracture hydraulic aperture as a function of confining stress under three loading-unloading cycles is explored for sample A.

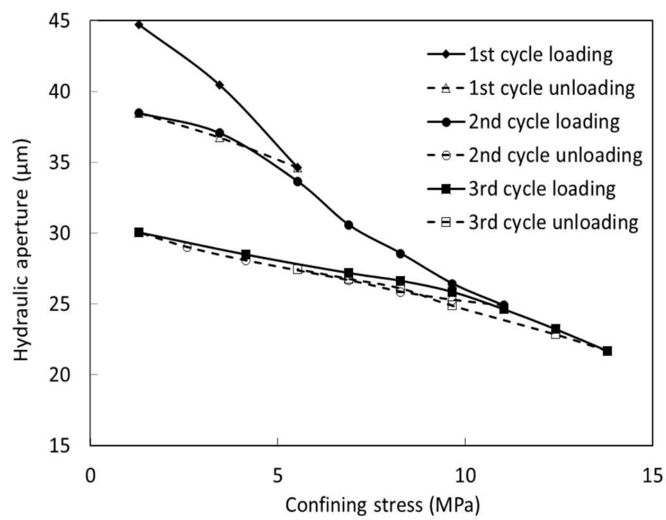

Figure 2. Variations of hydraulic aperture as a function of confining stress for sample A

It is observed in Figure 2 that the hydraulic aperture is decreased due to increasing confining stress during all loading cycles. Additionally, the hydraulic aperture does not fully recover during unloading. The observed behavior for cement fractures in this study is consistent with those of the rock fractures (Bandis et al., 1983; Zhang and Nemcik, 2013; Chen et al., 2015; Zhou et al., 2015) and cement-casing microannuli (Stormont et al., 2018). Considering the similarity of the flow mechanism between cement and rock fractures, it is postulated that the cement fracture surface asperities were crushed under compression, which reduced the fracture aperture and increased the tortuosity of the flow path, and thereby reduced the permeability and hydraulic aperture of the fracture (Raven and Gale, 1985; Zou et al., 2013). The hysteresis behavior is attributed to the plastic deformation of asperities which caused the non-recoverable reduction in the hydraulic aperture observed in these results (Stormont et al., 2018).

3-2- Effect of pore pressure

Two samples (A and B) with different hydraulic apertures and surface roughness characteristics were selected to investigate the effect of pore pressure on the hydraulic aperture of cement fractures. Nitrogen gas was used as the flowing fluid in sample A; both gas and liquid (silicone oil) were used in sample B to determine the effect that fluid type may have on the permeability variations with pore pressure. The results are plotted in the form of hydraulic aperture versus pore pressure in Figures 3, 4 and 5 for each sample and fluid type.

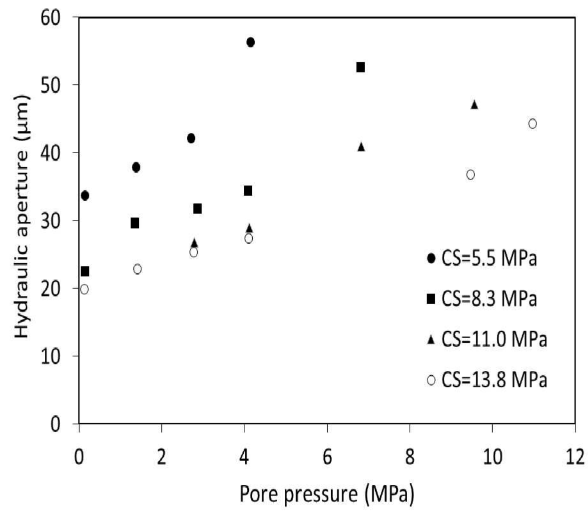

Figure 3. Hydraulic aperture determined from gas flow measurements as a function of pore pressure at different confining stresses for sample A

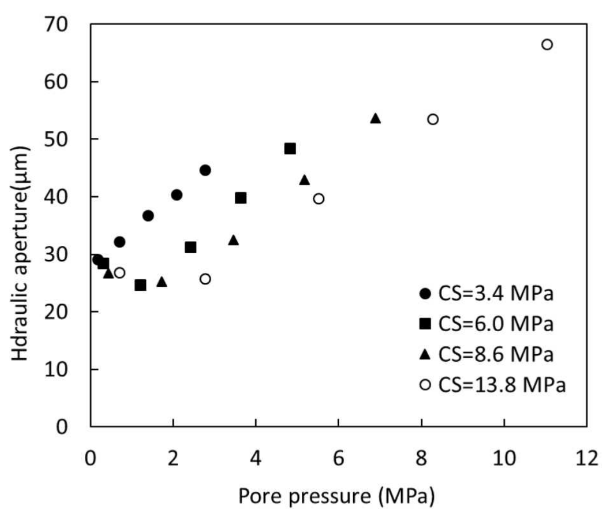

Figure 4. Hydraulic aperture determined from gas flow measurements as a function of pore pressure at different confining stresses for sample B

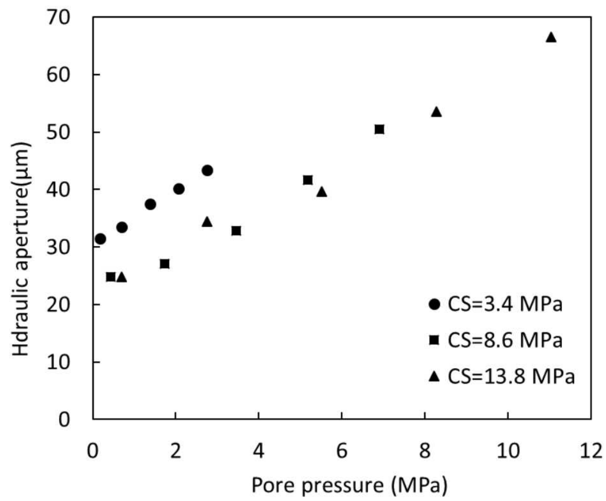

Figure 5. Hydraulic aperture determined from oil flow measurements as a function of pore pressure at different confining stresses for sample B

The results indicate that regardless of type of the fluid (gas and oil), the hydraulic aperture of both samples increase as the pore pressure is increased at all confining stresses. Taken together, these results show that the hydraulic aperture can change in response to varying the fluid pressure. The obtained results are incorporated into the numerical modeling presented in the next section.

4- Numerical simulations

Simulations of gas flow through a wellbore system containing cement fractures were conducted. A finite difference model was developed and used with the experimental results as input for these simulations. The numerical code allows the gas flow to be modeled solving for either visco-inertial flow (Equation 1) or by assuming only viscous flow (b=0). For some simulations, the hydraulic aperture was described as a function of pore pressure based on the experimental results.

The finite difference model employs second order, central differencing spatial discretization and is solved explicitly in time using MATLAB script. The numerical model was applied to a geometry that is consistent with a wellbore associated with a hydrocarbon storage cavern (e.g., Nemer et al., 2016). Flow was modeled passing through the cemented annulus formed between a 34 cm (13 in) and a 51 cm (20 in) diameter casing of a 600 m (1968 ft) deep wellbore. The flow path was modeled as equivalent to 4 radial fractures in the cemented annulus that extended from depth to the surface. The cemented annulus was assumed to extend to the surface as is typical for a wellbore of this type. The initial condition was gas at atmospheric pressure in the fractures.

A constant pressure of 6.0 MPa (870 psi) was imposed at the bottom of the model. The boundary at the top of the model was a fixed volume to simulate pressure build-up and the wellhead. Volume was fixed at 0.02 m^3 (0.7 ft^3), an assumed value that is consistent with that used by others in modeling sustained casing pressure (Lackey, 2017). For the cases of pore pressure dependent aperture, the fracture aperture varied from 20 to 27 microns over the range of pore pressures in these simulations, which corresponds to an effective permeability of the cemented annulus of about 1 to 4 x 10^{-14} m^2.

The wellhead pressure build-up response was explored for 4 different conditions including fractures with a constant 20 microns aperture with and without considering visco-inertial flow, fractures with pore pressure dependent aperture with and without visco-inertial flow.

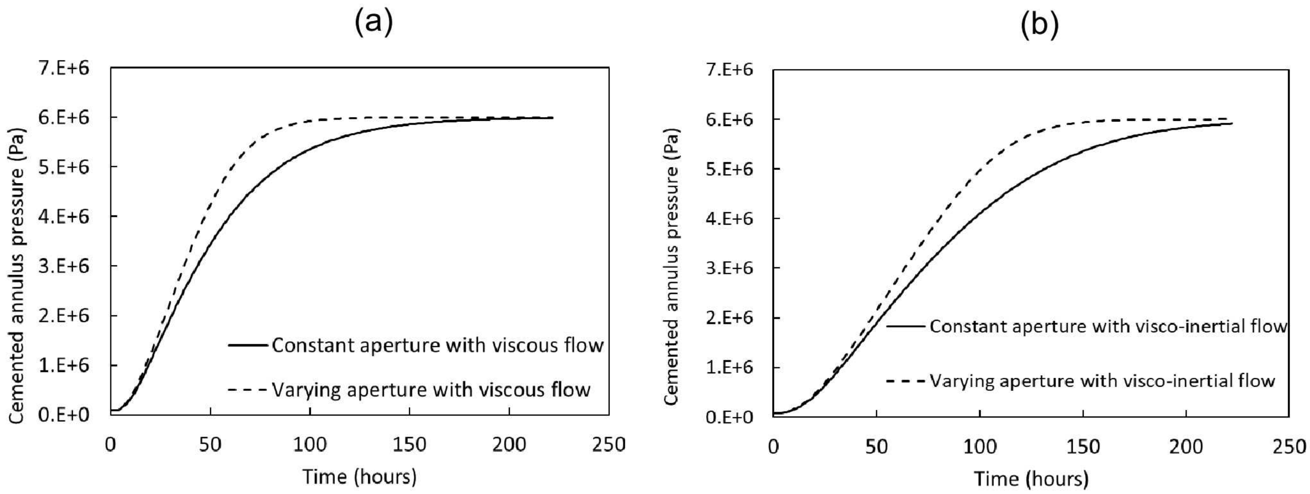

Figure 6. Pressure build-up at surface in cemented annulus for simulations with constant and pore pressure dependent fracture aperture assuming (a) only viscous flow and (b) visco-intertial flow

The results are displayed in Figure 6 and reveal that including the effect of pore pressure on the fracture aperture (varying aperture) accelerates the pressure buildup at the wellhead for both assumed flow regimes (Figures 6a and 6b). When the aperture is a function of pore pressure, it props open as the gas moves upward in the fracture; consequently, the flowrate increases and the pressure builds up more quickly at the wellhead.

Comparing the results in Figures 6a and 6b, we note that visco-inertial flow significantly slows the rate of pressure build-up at the wellhead compared to the cases where flow was assumed to be only viscous. This is because the inertial component of the flow consumes some of the energy (pressure gradient) driving the flow and thereby reduces the flowrate. The amount of visco-inertial flow that will occur is indirectly related to pore pressure as it increases with the flow velocity and pressure gradient (Equation 1).

The results indicate that both pore pressure in the fracture and visco-inertial flow (which is indirectly a function of the pore pressure as it increases with the pressure gradient) significantly affect the wellbore pressure build-up. Therefore, in order to accurately describe flow in the wellbore system, these effects should be taken into account when performing numerical simulations.

The results presented here are for one geometry and a set of assumed conditions as an illustrative example of the impact of visco-inertial flow and pore pressure on flow through a fractured wellbore cement. Under different conditions, different impact may be expected. Moreover, the confining stress was assumed constant in the numerical simulations presented in this study. Further investigations are required to evaluate the simultaneous effects of confining stress and pore pressure on the fluid flow behavior through wellbore cement fractures.

5- Conclusions

Permeability and hydraulic aperture of fractured cement samples were measured under different confining stress and pore pressure (gas and oil) combinations. Data were evaluated using the Forchheimer equation that includes both viscous and visco-inertial flow. The results indicate a strong correlation of increasing fracture permeability with an increasing fluid (pore) pressure for both oil and gas flow. Results confirm the hypothesis that elevated fluid pressure props wellbore cement fractures open and significantly increases the permeability and leakage rate. On the contrary, the hydraulic aperture decreases when increasing the confining stress.

The experimental results were incorporated into a numerical model that estimates the wellhead pressure response for a wellbore system with a thoroughgoing annular cement fracture. Results from the numerical simulations show that the wellhead response is substantially affected by the fluid pressure as well as visco-inertial flow in the fracture system. Visco-inertial flow significantly slows the rate of pressure buildup at the wellhead, whereas considering the effect of pore pressure on the fracture aperture (varying aperture) accelerates the pressure buildup. It is recommended to consider the effects of visco-inertial flow and pore pressure when simulating the fluid flow through fractured wellbore systems.

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