A Novel Approach to Detect Tubing Leakage in Carbon Dioxide (CO$_2$) Injection Wells via an Efficient Annular Pressure Monitoring

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Abstract: Due to the unique corrosion potential and safety hazards of carbon dioxide (CO$_2$), tubing leakage of CO$_2$ in a CO$_2$ injection well may occur and lead to undesired consequences to environment, human being and facility. As a result, quick detection of any carbon dioxide leakage and accurate identification of leakage location are extremely beneficial to obtain critical information to fix the leakage in a prompt manner, prevent incidents / injury / casualty, and achieve high standards of operational safety. Annular pressure monitoring has been identified as an effective and reliable approach for detecting tubing and casing leakage of fluids (including hazardous gas like CO$_2$) in a well. Accurate prediction of annular pressure change associated with the leakage will certainly help the operation. In an effort to assess annular pressure characteristics and thus improve understanding of tubing leakage, a multiphase dynamic modeling approach has been applied to simulate the carbon dioxide, completion brine and formation water's flow and associated heat transfer processes along wellbore, tubing and annulus in carbon dioxide injection wells designed for carbon capture and sequestration (CCS) [1] projects. Two operational scenarios – one for routine CO$_2$ injection and another for well shut-in – have been considered in the investigation. Key parameters that may have significant impacts on the process have been investigated. On the basis of the investigation, a novel approach has been proposed in the paper for quickly detecting the leakage of carbon dioxide in a CO$_2$ injection well. Two simple equations have been developed to pinpoint the leakage location by means of real-time measurement and monitoring of the change in annular pressure. Recommendations based on a series of dynamic simulation results have been provided and can be readily incorporated into detailed operating procedures to enhance carbon dioxide injection wells' operational safety.

Keywords: Annular pressure, carbon capture and sequestration, carbon dioxide, injection well, OLGA, tubing leakage.

1. INTRODUCTION

All well operations inherently carry an element of risk. Nevertheless, carbon dioxide (CO$_2$) injection wells for carbon capture and sequestration (CCS) projects [1] may encounter additional and unique risks not normally experienced in conventional oil and gas field operations – potential exposure to CO$_2$ at undesired high concentrations, which may lead to irreversible damage to environment, injury and cause casualty to human beings and animals. At normal atmospheric concentrations (around 0.037%) CO$_2$ is nontoxic; however as concentrations rise, adverse effects on the human body become progressively more noticeable and debilitating. Prolonged exposure to CO$_2$ concentrations above 6% will result in unconsciousness and if the resultant oxygen level drops below 16% death will even occur [2]. The lack of odor and color of carbon dioxide further compounds the risks.

People with normal cardiovascular, pulmonary (respiratory) and neurological functions are able to tolerate CO$_2$ concentrations up to 1.5% for several hours without any ill effects. Above that level impairment of functions is progressive as the CO$_2$ concentration continues to rise and length of exposure increases. Under an unfortunate circumstance of CO$_2$ leakage, the CO$_2$ concentration may reach and progress further beyond the limits in a short time.

Loss of wellbore and pipeline integrity is often the root cause of many CO$_2$-related incidents, including a number of fatal ones all over the world in the past. Most of the incidents are associated with CO$_2$ leakage caused by wellbore and/or flowline failures. CO$_2$, in combination with water will generate carbonic acid and cause severe corrosion of conventional steels, which will eventually lead to leakage of hazardous gas (i.e., CO$_2$ in this case) and introduce severe dangers to human being's health and even life. As such, all these issues must be appropriately addressed, all potential scenarios investigated and necessary mitigation steps planned and incorporated into the applicable field operating procedures before starting up any carbon dioxide injection operation.

As more and more CCS projects are being planned and executed all over the world to address the global warming issue [3], more and more CO$_2$ injection wells will be designed, drilled, completed and applied to inject CO$_2$ to applicable underground geological aquifers. Substantial risks are anticipated with more CO$_2$ exposure to human being and environment as a result of potential hazardous gas leakage originated from a CO$_2$ injection well. Hence, it becomes critical and beneficial to have competent tools and approaches developed for quickly detecting any potential CO$_2$ leakage and accurately locating the leakage position and source of the leakage. In order to achieve the objective, a comprehensive investigation has been conducted for improving our understanding of the important characteristics of CO$_2$ leakage in a wellbore and the results are to be presented in

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the paper. Note that the focus of this investigation is on the CO_2 leakage in the wellbore of a CO_2 injection well.

2. METHODOLOGY

CO_2 leakage in a CO_2 injection well may occur through a tubing leak, a casing leak or a packer leak. The leakage may result in significant or non-trivial change in annular pressure. Therefore, on top of assessing the trapped fluid status inside a tubing-casing annulus and managing annulus pressure build-up (APB), annular pressure may also be applied for detecting any leak through key well completion components (Fig. **1**) such as tubing, casing, packer, etc.
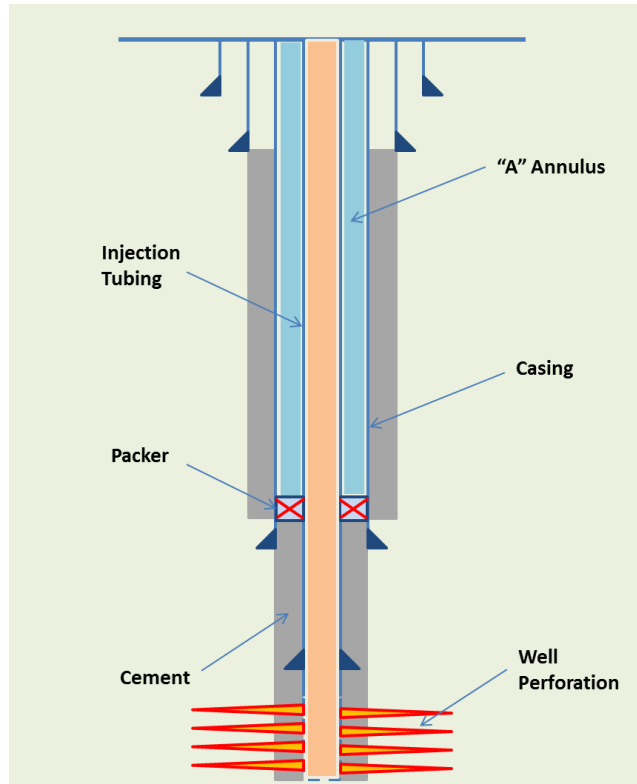
Fig. (1). Completion Schematics of a Carbon Dioxide Injection Well.

There are two major factors that control the annular pressure: heat transfer (thermal expansion or contraction associated with CO_2 injection and backflush operation) and leak through completion components such as production tubing and casing. For a typical CCS project, at the target CO_2 injection temperature and rate, the heat transfer associated with CO_2 injection is not expected to cause substantial increase in the annular pressure. Similarly, a casing leak to the annulus should not cause significant change in the annular pressure, either; as long as the annulus fluid attains significant exposure time to ambient environment before it gets sealed. Hence, the potential tubing leak and backflush operation become the major players that could potentially bump up the annular pressure.

The initial annulus pressure and temperature profiles – the profiles at the time the annulus is closed – need to be estimated in order to appropriately predict the change in the annular pressure during CO_2 injection, start up, shut in, as

well as any potential tubing and casing leaks. The initial annulus pressure and temperature profiles depend on the detailed sequence and process of well drilling and completion operation. A number of key parameters must be taken into account, including drilling fluid pumping (time, fluid property, fluid temperature, pumping rate), time interval between drilling and completion, completion brine recirculation (brine property, pumping rate, temperature, time, procedure), ambient temperature profile (geothermal), annulus sealing / closing, and so on.

No doubt, the fluid flow and heat transfer related to tubing leakage will be a transient (dynamic) process. For transient monophasic or multi-phase flow in pipelines or wellbores, steady state models are inappropriate. Therefore, a comprehensive software package that can handle transient monophasic or multiphase fluid flow and heat transfer is required. Transient modeling is an essential component for feasibility studies and field development design, and used extensively in both offshore and onshore developments to investigate transient behavior in pipelines and wellbores. OLGA [4], a well-established software package that has been applied in a number of industries including oil and gas, chemical, process, and so on, has been chosen for this study. It is a fully transient dynamic pipe and wellbore flow model which uses a modified "two-fluid" models to solve a series of mass, momentum and energy conservation equations: 5 mass equations of gas, oil droplet, continuous oil, water droplet, and continuous water; 2 momentum equations of gas and liquid; and 1 energy equation for the mixture. Transient simulation with the OLGA simulator provides an added dimension to steady-state analyses by predicting system dynamics such as time-varying changes in flow rates, fluid compositions, temperature, solids deposition and operational changes.

Several OLGA models have been developed to investigate flow and heat transfer associated with drilling, completion and CO_2 injection processes mentioned above in an effort to mimic the well drilling, completion and CO_2 injection procedures, and eventually arrive at reliable prediction of wellbore and annulus pressure profiles.

Some of these OLGA models have been applied in this study to investigate the annular pressure characteristics under the circumstance of tubing leakage.

3. DYNAMIC SIMULATION RESULTS

The results based on a series of comprehensive OLGA transient simulations will be presented in this section. Leakage at a number of wellbore depths has been thoroughly evaluated, including the top, the middle and the bottom of the annulus. Both routine CO_2 injection and well shut-in have been considered.

3.1. Leakage During Well Injection

Tubing leakage, including any fluid flow or mass communication between tubing and tubing-casing annulus (a.k.a. "A" annulus, Fig. **1**) caused by packer failure, hanger failure or seal failure, is expected to result in non-trivial increase in annular pressure. As shown in Fig. (**2**), the OLGA simulation results clearly suggest that the annular pressure does increase
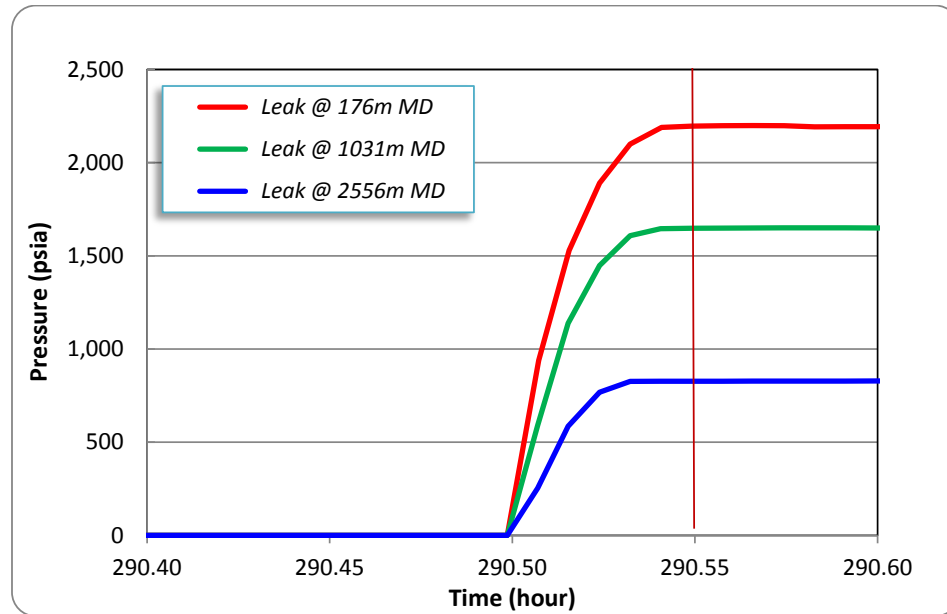
Fig. (2). Annular Pressure Change during a Tubing Leakage.

rapidly right after the onset of tubing leaks. The annular pressure increase has been observed along all the annulus location (depth) like the three depths – 176m MD, 1031m MD and 2556m MD – displayed in Fig. (**2**).

The annular pressure increase associated with the tubing leak is caused by an introduction of a flow conduit between the injection tubing and the "A" annulus (tubing-casing annulus, Fig. **1**). The whole leakage process is clearly illustrated in (Fig. **3**) that shows a series of snapshots of water (completion brine) holdup[1] profiles (green curves) prior to and shortly after the leakage. For this case, a water holdup less than 1 in a depth means that there is CO_2 present at the specific location.

The leakage follows the sequence listed below,

a. A small amount of CO_2 rapidly escapes to the annulus through the leakage point (Fig. **3b**);

b. The escaped CO_2 moves towards the top of the annulus (Fig. **3c-3h**);

c. The escaped CO_2 reaches the top of the annulus (Fig. **3i**);

d. The CO_2 settles down at the top of annulus (Fig. **3j**).

The leakage would lead to the full annular pressure increase in around 0.05 hours or 3 minutes (Fig. **2**).

A number of CO_2 tubing leakage locations have been investigated and the results are shown in both Fig. (**4**) and Table **1**, which clearly suggest that the amount of annular pressure increase closely corresponds to the leakage location represented by TVD or total vertical depth. The shallower the leakage, the higher the increase in the annular pressure would be (Fig. **4**). A leakage at the top could lead to an increase of over 2100 psi in the annular pressure, whereas the

leakage in the bottom could cause an increase more than 800 psi (Table **1**).

The annular pressure increase has been found to be well correlated to the leakage depth (the correlation coefficient is as high as 0.9994, in a very close proximity of unity):

$$\Delta P_a = 2306.9 - 0.7617 * Z \qquad \text{Eq. (1)}$$

where ΔPa is defined as the increase in the annular pressure in psi due to the CO_2 leakage and Z represents the depth of the leakage point, in meter.

Eq. (1) can be applied to estimate the CO_2 tubing leakage based on the amount of the annular pressure increase:

$$Z = 1.3129 * (2306.9 - \Delta P_a) \qquad \text{Eq. (2)}$$

From a real-time monitoring of the annular pressure, the ΔPa can be calculated and used to determine the carbon dioxide leakage depth by means of Eq. (2).

3.2. Leakage During Well Shut-in

Similar to a routine CO_2 injection, in case of tubing leakage during well shut-in, the annular pressure has also been found to increase, although at slightly smaller pace (Table **2** and Fig. **5**) than those predicted for a flowing CO_2 injection well.

Once again, a very good correlation can be found between the annular pressure increase and the depth of the leakage point:

$$\Delta P_a = 2067 - 0.7324 * Z \qquad \text{Eq. (3)}$$

And the relationship may also be applied to pinpoint the location of the tubing leakage of carbon dioxide:

$$Z = 1.3654 * (2067 - \Delta P_a) \qquad \text{Eq. (4)}$$

4. DISCUSSIONS

Tubing leak and heat transfer are the two major factors that would contribute to the change (increase) in an annular

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[1] Simply put, water holdup is defined as the fraction of water occupied cross-section area over a total cross-section area. Water holdup of 1 is equivalent to 100% water in the cross-section, whereas water holdup of 0 means no water in the cross-section.
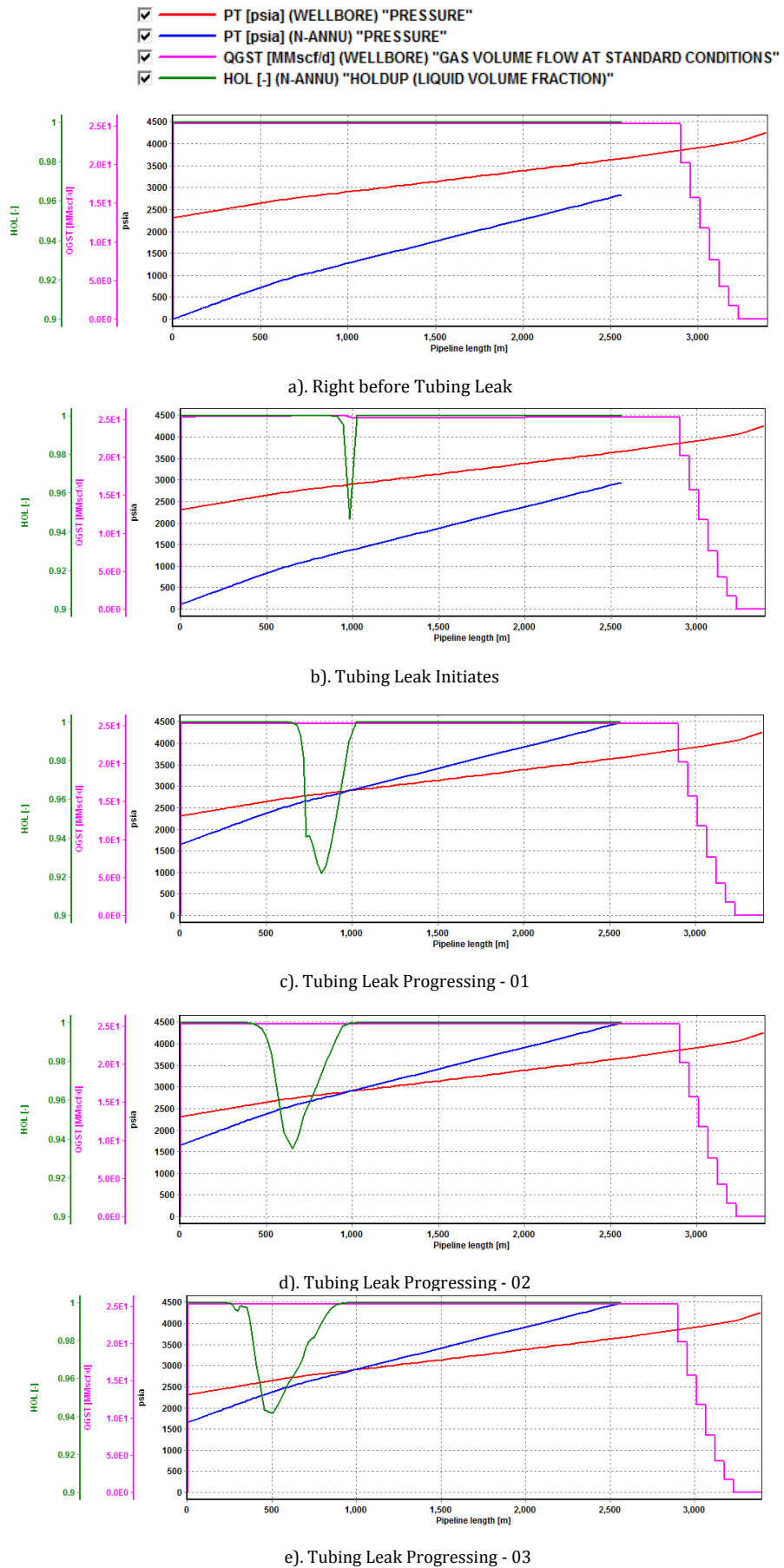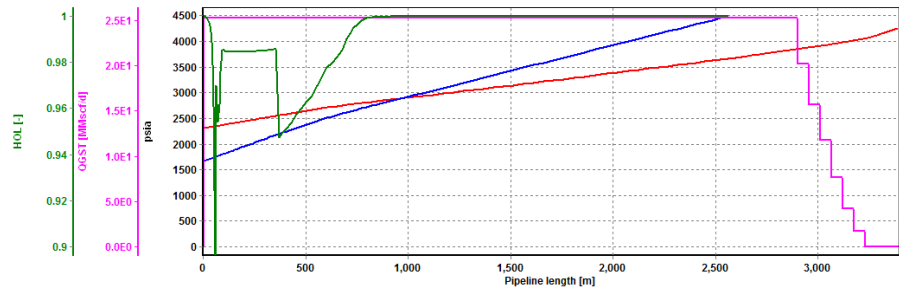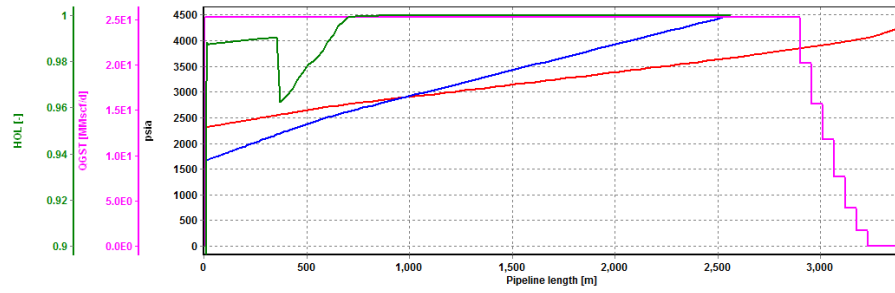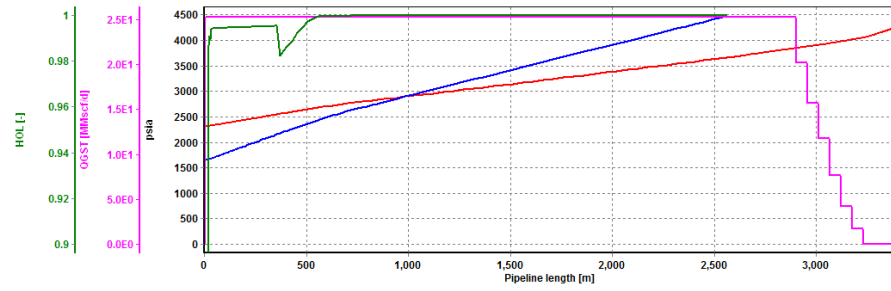
☑ ── PT [psia] (WELLBORE) "PRESSURE"
☑ ── PT [psia] (N-ANNU) "PRESSURE"
☑ ── QGST [MMscf/d] (WELLBORE) "GAS VOLUME FLOW AT STANDARD CONDITIONS"
☑ ── HOL [-] (N-ANNU) "HOLDUP (LIQUID VOLUME FRACTION)"

a). Right before Tubing Leak

b). Tubing Leak Initiates

c). Tubing Leak Progressing - 01

d). Tubing Leak Progressing - 02

e). Tubing Leak Progressing - 03

Fig. (3) contd…..
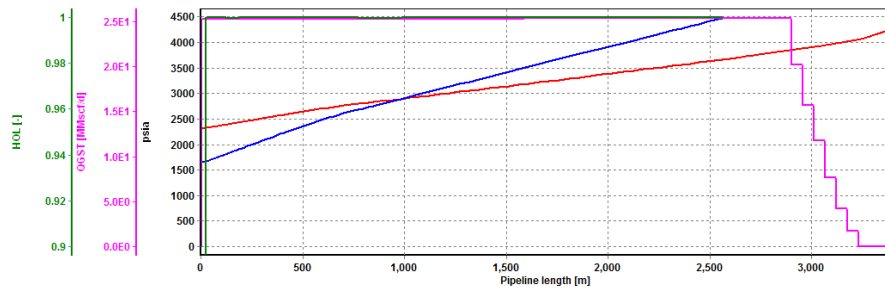
f). Tubing Leak Progressing - 04

g). Tubing Leak Progressing - 05

h). Tubing Leak Progressing - 06
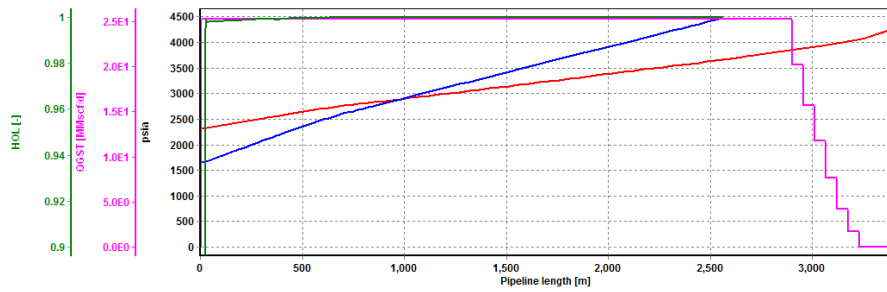
i). Tubing Leak Progressing - 07

j). Tubing Leak Completes

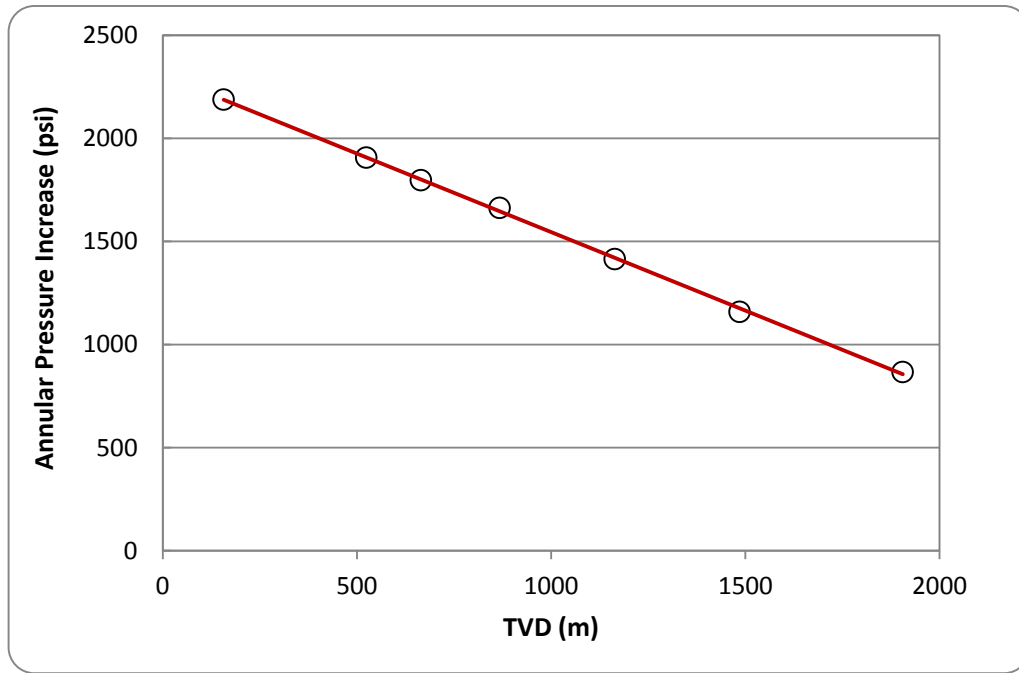**Fig. (3).** Snapshots Illustrating the CO_2 Tubing Leak Process.

Fig. (4). Variation of Annular Pressure Change with Leakage Depth.

Table 1.   **Annular Pressure before and after Tubing Leak during CO$_2$ Injection.**

Leak Location	Annular Pressure		
TVD (m)	Prior Leak	Post Leak	Change (psi)
157	0	2188	2188
524	0	1906	1906
665	0	1797	1797
867	0	1663	1663
1164	0	1414	1414
1486	0	1158	1158
1905	0	867	867

Table 2.   **Annular Pressure before and after Tubing Leak during CO$_2$ Injection Shut-in.**

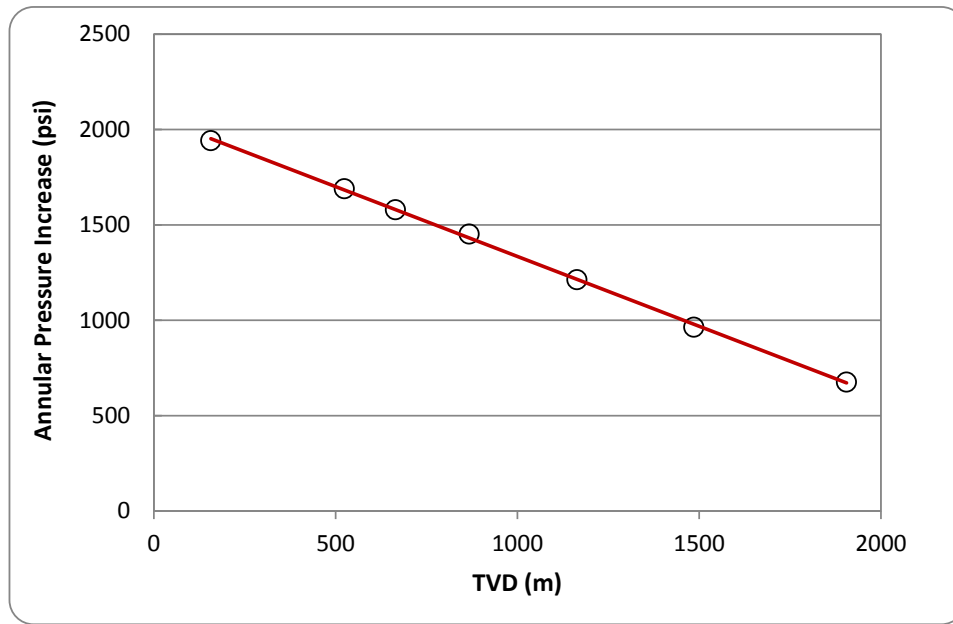| Leak Location	Annular Pressure		
TVD (m)	Prior Leak	Post Leak	(psi)
156.7	0	1941	1941
524.2	0	1689	1689
664.9	0	1579	1579
867.4	0	1451	1451
1164.0	0	1212	1212
1485.6	0	964	964
1905.3	0	676	676

Fig. (5). Variation of Annular Pressure Change with Leakage Depth (Well Shut-in Scenario).
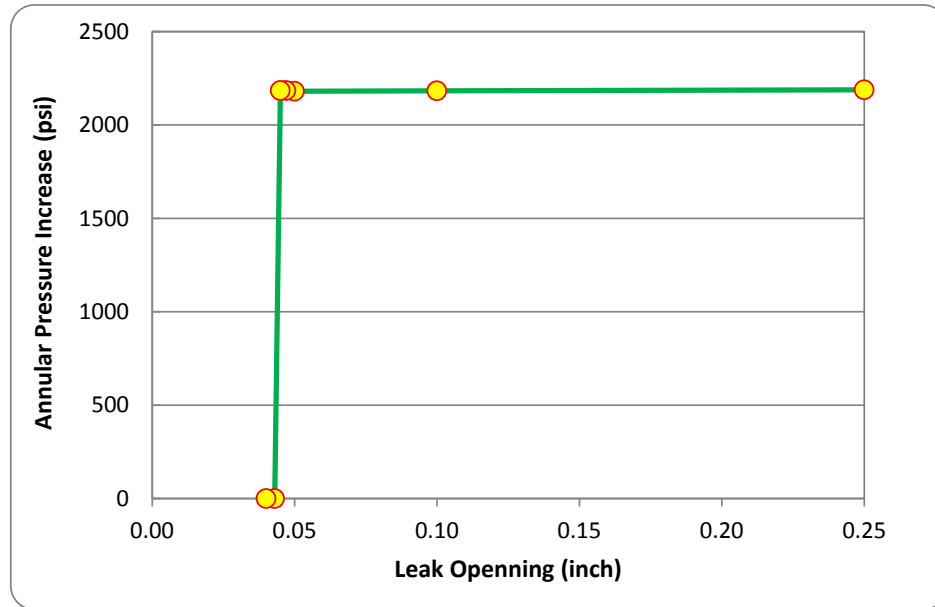

Fig. (6). Variation of Annular Pressure Change at 176m MD with the Size of Leakage Opening.

pressure. As has been shown so far in the present paper, depending on the leakage location, the tubing leak would potentially lead to an increase in the annular pressure at around 600 psi to 2000+ psi under the conditions investigated, all over a very short time period (in minutes). At high flowing fluid (CO_2 for CO_2 injection, and formation water or injected CO_2 during a well backflush operation) temperature, heat transfer could also result in substantial increase (1000s psi) in the annular pressure, but the increase would last much longer (in hours) and the increase appears to continue for a longer time period, although at a slower pace. As such, by constantly monitoring the annular pressure change over time, it may be possible to distinguish between an annular pressure increase caused by heat transfer and an annular pressure boost due to CO_2 leakage through tubing.

In this study, a quarter inch opening has been set in the majority of the dynamic modeling simulations presented in this paper. This setting was originated from a sensitivity study where different dimensions of the leakage opening – ranging from 0.02 inch to 0.25 inch – have been investigated. On the basis of the sensitivity study, it has been observed that as long as the opening is larger than a threshold for the fluid to flow, the annular pressure increase will be about the same, except for the time it takes to achieve the annular pressure increase. The smaller the opening, the longer the annular pressure increase would take. The threshold has been estimated at around 0.045 inch – a very small value – on the basis of the simulation results as shown in Fig. (**6**).

CONCLUSION AND RECOMMENDATIONS

Tubing leak and heat transfer have been identified as the two major factors that would contribute to the change (increase) in an annular pressure in a carbon dioxide injection well. Depending on the leak location, the tubing leak would potentially lead to an increase in the annular pressure at around 600 psi to 2000+ psi under the conditions investigated, all over a very short time period (in less than five minutes).

It is interesting to note that for either a flowing or a shut-in CO_2 injection well, the amount of pressure boost in the annulus associated with a CO_2 tubing leak correlates extremely well with the leakage depth. This feature may be potentially applied to estimate the location of tubing leak in the future based on the real-time measurement and monitoring of the annular pressure in a CO_2 injection well. It is believed that such practise will help field operators and engineers to detect CO_2 leakage and estimate the leakage point on a timely basis, take necessary and prompt measures accordingly to fix the leakage, and thus reduce the risk of damage to human beings and environment.

It is highly recommended to calibrate and fine-tune the applicable OLGA models to available field measurement to improve the accuracy of the prediction by the approaches and the four equations [Eqs. (1) – (4)] presented in the present paper.

The annular pressure change is expected to be closely related to fluid (completion brine in particular) density which in turn relies on pressure and temperature. Fortunately, insignificant variation of the completion brine density is anticipated under the pressure and temperature conditions to be seen for most of the carbon dioxide injection wells designed for a CCS project. Therefore, the new equations proposed in the paper should yield reasonable predictions of either the amount of the annular pressure increase or the leakage location.

CONFLICT OF INTEREST

The authors confirm that this article content has no conflict of interest.

ACKNOWLEDGEMENTS

Declared none.

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