Transient Flow Modelling of the Impact of CO₂ Stream Impurities During Geological Sequestration

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Abstract
Following the quest for energy sustainability and cleaner environment, Carbon Capture and Storage (CCS) is expected to play a significant role in reducing carbon dioxide (CO₂) emissions. Outlining the impact of impurities (such as O₂, N₂, H₂O, H₂S, Ar, SOₓ, NOₓ, Hg etc.) in the gas or dense phase CO₂ stream arising from fossil fuel power plants, or large scale industrial emitters, is of fundamental importance to the safe and economic injection of the captured CO₂. This study investigates the impact of varying range of impurities expected from the main CO₂ capture technologies used with fossil-fuelled power plants on the pressure and temperature profiles during CO₂ sequestration. The analysis presented is with respect to the range of impurities present in CO₂ streams captured using pre-combustion, post-combustion and oxy-fuel technologies. Given the possibility of rapid, quasi-adiabatic Joule-Thomson expansion when high pressure CO₂ is injected into a low pressure injection well, which may lead to significant temperature drops posing several risks, including: blockage due to hydrate and ice formation with the formation water in the perforations at the near well zone; thermal stress shocking of the wellbore casing steel leading to its fracture and ultimate escape of CO₂. Therefore, in this study we investigate the time-dependent behaviour of the CO₂ stream at the wellhead and perform an analysis on varying CO₂ stream impurities combination.

Keywords: CO₂ injection, CO₂ stream, impurities, ramp-up
Introduction

Carbon capture and geological storage represents an option that could play a prominent role in reducing anthropogenic CO$_2$ emissions into the atmosphere, comparable in size with improving energy efficiency and energy conservation. The principle is quite simple: capture CO$_2$ from large sources before it would be vented into the atmosphere, transport it to a storage site, usually by pipeline but also by ship where warranted, and inject it at least several hundreds of meters deep below the ground surface if onshore, or below the seabed if offshore. Geological media suitable for CO$_2$ storage must have the necessary capacity to store the intended volumes of CO$_2$, must have the injectivity needed to take in the CO$_2$ at the rate that it is supplied, and must confine the CO$_2$ to the storage site and impede its lateral migration and/or vertical leakage to other strata, shallow potable groundwater, soils and/or atmosphere. Such geological media are oil and gas reservoirs and deep saline aquifers that are found in sedimentary basins.

Impurities in the CO$_2$ stream have the potential to affect the efficiency and safety of the storage systems. For instance, the presence of impurities may increase risks associated with corrosion and alter the phase behaviour of the CO$_2$ stream. The presence of impurities is likely to have a significant effect on the phase behaviour, with implications for the design and operation of pipelines and injection wells. The presence of impurities could also pose a significant threat of increased corrosion of pipeline and well materials. Impurities in CO$_2$ captured from combustion based power generation with CCS can arise in a number of ways. Water is a major combustion product and is considered an impurity in the CO$_2$ stream. The elements inherently present in a fuel such as coal include sulphur, chlorine and mercury, and are released upon complete or incomplete combustion and form compounds in the gas phase which may remain to some extent as impurities in the CO$_2$ after it is captured and compressed. The oxidising agent used for combustion such as air may result in residual impurities of N$_2$, O$_2$ and Ar (Porter et al, 2015).

Literatures on CO$_2$ stream impurities

Several literatures (Alex, 2016; Hajiw et al, 2018; IEAGHG, 2011; Mahgerefteh et al, 2012; Wang et al, 2011; Wang et al, 2015; Wetenhall et al, 2014) on the effects of CO$_2$ stream impurities are available and mostly focussed on the rate of CO$_2$ injectivity, phase behaviour, storage capacity, transportation, compression and pipeline. Wang et al, (2011) developed a simple formula to enable quick determination of the effects of impurities in CO$_2$ streams on geological storage. The study highlighted that non-condensable impurities such as N$_2$, O$_2$ and Ar greatly reduce CO$_2$ storage capacity of geological formations, and there is a maximum reduction of the storage capacity at a certain pressure under a given temperature. Their revealed that impurities which are more condensable than CO$_2$, such as SO$_2$, can increase the storage capacity, and there is a maximum increase at a certain pressure under a given temperature; change of density caused by non-condensable gas impurities results in lower injectivity of impure CO$_2$ into geological formations. The importance of CO$_2$ impurities on the range of operation, safety considerations, fracture, cracking, corrosion control, dispersion in the event of a release, fluid density, operating pressure and temperature and the quantity of CO$_2$ that can be transported was studied by Wetenhall et al., (2014). The study summarises the “impact of CO$_2$...
impurity on CO₂ compression, liquefaction and transportation” following various capture technologies. Porter et al., (2015) studied CO₂ purification technologies available for the removal of CO₂ impurities from raw oxy-fuel flue gas, such as Hg and non-condensable compounds. They concluded over 99% CO₂ purity levels are achievable using post-combustion capture technologies with low levels of the main impurities of such as N₂, Ar and O₂. However, CO₂ capture from oxy-fuel combustion and integrated gasification combined cycle power plants will need to take into consideration the removal of non-condensable acid gas species, and other contaminants. The actual level of CO₂ purity required will be dictated by a combination of transport and storage requirements, and process economics.

This paper addresses the fundamentally important issues surrounding the impact of typical CO₂ impurities in the injection of gas or dense phase CO₂ stream from fossil fuel power plants and other industries fitted with carbon capture and storage (CCS) technologies, upon the safe and economic transportation of CO₂ mixture. Understandably, the ultimate composition of the CO₂ stream captured from fossil fuel power plants or other CO₂ intensive industries and transported to a storage site using high pressure pipelines will be governed by safety, environmental and economic considerations. This study investigates the impact of varying range of impurities expected from the main CO₂ capture technologies used with fossil-fuelled power plants on the pressure and temperature profiles during CO₂ sequestration. The analysis presented is with respect to the range of impurities present in CO₂ streams captured using pre-combustion, post-combustion and oxy-fuel technologies.

Before the steady injection of CO₂ into the reservoir can be started, it is necessary to perform time-dependent operations to estimate important reservoir properties, e.g. permeability and pressure. Such operations include start-up, shut-in and emergency shut-down, which prove to be critical in the overall design of the well (Böser & Belfroid, 2013). Even after steady injection conditions are reached the well may be shut in and started up for maintenance of the upstream transportation system or other routine checks. It is therefore of paramount importance to be able to predict the behaviour of the CO₂, in terms of pressure and temperature along the full length of the well, to characterise and quantify potential risks (Li, et al, 2015).

Figure 1 shows a schematic diagram of an ideal CO₂ injection well. From the top of the injection well to the reservoir the CO₂ is affected by several physical effects that contribute to the pressure and temperature profile along the well. Heat will be exchanged with the surrounding rocks along the well. This will not only affect the fluid properties of the CO₂ in the well but also the rock will be cooled or heated by the fluid flow.
This study is focused on modelling the transient flow behaviour of carbon dioxide (CO₂) stream with impurities during geological sequestration. Injecting a highly-pressurised CO₂ into a formation with lower pressure will induce a rapid quasi-adiabatic Joule-Thomson expansion effect. As such, the resulting effect on the formation may be:

- Blockage due hydrate and ice formation with interstitial water around the wellbore and
- Thermal shocking of the wellbore casing steel, leading to its fracture and ultimately escape of CO₂.
The model and fluid dynamics

Fig. 2 shows a schematic flow diagram of an injection tube. A control volume of a section of the tube is considered for analysis and derivation of model governing equations.

![Diagram of control volume in a vertical pipe](image)

Fig. 2: Schematic representation of a control volume within a vertical pipe and the forces acting on it

Where $F_p$, $F_f$, $F_g$, $\rho$, and $u$ are pressure force, frictional force, gravitational force, fluid density and velocity respectively. $L$, $D_p$, and $\Delta x$ are well depth, diameter and differential control volume.

This study considers a purely vertical injection tube only hence, pipe inclination is unaccounted for. The following simplified assumptions are applied:

- One-dimensional flow in the pipe
- Homogeneous equilibrium fluid flow
- Negligible fluid structure interaction through vibrations
- Constant cross section area of pipe

The assumption of homogeneous equilibrium flow means that all phases are at mechanical and thermal equilibrium (i.e. phases are flowing with same velocity and temperature) hence the three conservation equations should be applied for the fluid mixture. Although, in practice usually the vapour phase travels faster than the liquid phase, the HEM model has been investigated proven to have an acceptable accuracy in many practical applications.

The following gives a detailed account of the homogeneous equilibrium model employed for the simulation of the time-dependent flow of CO$_2$ in injection wells. The system of four partial differential equations for the CO$_2$ liquid/gas mixture, to be solved in the well tubing, can be written in the well-known conservative form as follows:
\[ \frac{\partial}{\partial t} Q + \frac{\partial}{\partial x} F(UQ) = S_1 + S_2 \]

where

\[ Q = \begin{pmatrix} \rho \Lambda \\ \rho u \Lambda \\ \rho \mathcal{E} \Lambda \\ \Lambda \end{pmatrix}, \quad F(Q) = \begin{pmatrix} \rho u \Lambda \\ \rho u^2 \Lambda + \Lambda \mathcal{P} \\ \rho u \mathcal{H} \Lambda \\ 0 \end{pmatrix}, \quad S_1 = \begin{pmatrix} 0 \\ p \frac{\partial \Lambda}{\partial x} \\ 0 \\ 0 \end{pmatrix}, \quad S_2 = \begin{pmatrix} 0 \\ \Lambda (f' + \rho \beta g) \\ 0 \\ 0 \end{pmatrix} \]

In the above, the first three equations correspond to mass, momentum, and energy conservation, respectively. The fourth equation describes the fact that the cross-sectional area \( \Lambda \) is, at any location along the well, constant in time, but might vary along the depth of the well. Moreover, \( u \) and \( \rho \) are the mixture velocity and density, respectively. \( \mathcal{P} \) is the mixture pressure, while \( \mathcal{E} \) and \( \mathcal{H} \) represent the specific total energy and total enthalpy of the mixture, respectively. They are defined as:

\[ \mathcal{E} = e + \frac{1}{2} u^2 \]

\[ \mathcal{H} = \mathcal{E} + \frac{\rho}{\rho_c} \]

where \( e \) is the specific internal energy. In addition, \( x \) denotes the space coordinate, \( t \) the time, \( f' \) the viscous friction force, \( q \) the heat flux, and \( g \) the gravitational acceleration. In the case of the HM, the assumption of mechanical equilibrium, i.e. no phase slip, is retained.

The system of partial differential equation (2) is an extension of the work previously done in (Oldenburg, 2007), (Celia & Nordbotten, 2009), by accounting for both a variable cross-sectional area and additional source terms. By analysing in more detail the various source terms appearing on the right-hand side of Eq. (2). The frictional loss \( f' \) in equation (2) can be expressed as

\[ f' = -f_w \frac{\rho u^2}{D_p} \]

where \( f_w \) is the Fanning friction factor, calculated using Chen’s correlation (Chen, 1979), and \( D_p \) is the internal diameter of the pipe.

The gravitational term includes

\[ \beta = \rho g \sin \theta \]

which accounts for the possible well deviation.

In Eq. (2) the source term \( Q \) accounts for the heat exchange between the fluid and the well wall. The corresponding heat transfer coefficient \( \eta \) is calculated using the well-known Dittus-Boelter correlation (Dittus & Boelter, 1930):
\[ \eta = 0.023 \, Re^{0.8} Pr^{0.5} \frac{k}{D_v} \]  

(7)

where \( k \), \( Re \) and \( Pr \) are the thermal conductivity, Reynold’s number and Prandtl’s number for the fluid. The heat exchanged between the fluid and the wall is calculated using the following formula:

\[ q = \frac{4}{D_p} \eta (T_w - T) \]  

(8)

\( T_w \) and \( T \) are the temperatures of the fluid and of the wall, respectively. Note that \( T_w = T_w(x, t) \), i.e. \( T_w \) is not assumed constant, but variable with time and space.

**Numerical method and injection well CO\(_2\) inlet conditions**

In this study, an effective model based on the Finite Volume Method (FVM), incorporating a conservative Godunov type finite-difference scheme (Godunov 1959, Radvogin et al. 2011, Cumber et al. 1994) is used. The FVM is well-established and thoroughly validated CFD technique. In essence, the methodology involves the integration of the fluid flow equations over the entire control volumes of the solution domain and then accurate calculation of the fluxes through the boundaries of the computed cells.

For the purpose of numerical solution of the governing equations they are written in a vector form (Toro 2010):

\[ \frac{\partial \mathbf{q}}{\partial t} + \frac{\partial \mathbf{f}}{\partial x} = \mathbf{S}, \]  

(17)

where

\[ \mathbf{Q} = (\rho, \rho u, \rho e)^T, \]

\[ \mathbf{F} = (\rho u, (\rho u^2 + P), u(\rho ue + \rho u^2 + P))^T \]

\[ \mathbf{S} = (\mathbf{S}^m, \mathbf{S}^{m \cdot c}, \mathbf{S}^{c})^T \]  

(18)

\( \mathbf{Q}, \mathbf{F} \) and \( \mathbf{S} \) are the vectors of conserved variables, fluxes and source terms respectively. The source terms \( \mathbf{S}^m, \mathbf{S}^{m \cdot c} \) and \( \mathbf{S}^c \) describe the effects of mass, momentum and heat exchange between the fluid and its surrounding respectively, as well as friction and heat exchange at the pipe wall.

**4.1 Injection well and CO\(_2\) inlet conditions**

The data used in this study obtained from the Peterhead CCS project include the well depth and pressure and temperature profiles, along with the surrounding formation characteristics as presented in (Li et al., 2015; Shell UK, 2015) and reproduced in Table 1. The Peterhead CCS project is aimed to capture one million tonnes of CO\(_2\) per annum for 15 years from an existing combined cycle gas turbine located at Peterhead Power Station in Aberdeenshire, Scotland. In the project, the CO\(_2\) captured from the Peterhead Power Station would have been transported by pipeline and then injected into the depleted Goldeneye reservoirs. Despite the cancellation of the project
funding, useful information was already available, given that the Goldeneye reservoir had been used for extraction of natural gas for many years.

Table 1: Goldeneye injection well and CO\textsubscript{2} inlet conditions (Shell UK, 2015)

<table>
<thead>
<tr>
<th>Input parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wellhead pressure, bar</td>
<td>36.5</td>
</tr>
<tr>
<td>Wellhead temperature, K</td>
<td>280</td>
</tr>
<tr>
<td>Bottom-hole temperature, K</td>
<td>353.15</td>
</tr>
<tr>
<td>Well depth, m</td>
<td>2580</td>
</tr>
<tr>
<td>CO\textsubscript{2} injection mass flow rate, kg/s</td>
<td>linearly ramped-up to 38.5 kg/s in 5 minutes</td>
</tr>
<tr>
<td>Injection tube diameter, m</td>
<td>0.125m</td>
</tr>
<tr>
<td>CO\textsubscript{2} inlet pressure, bar</td>
<td>115</td>
</tr>
<tr>
<td>CO\textsubscript{2} inlet temperature, K</td>
<td>277.15</td>
</tr>
</tbody>
</table>

Outflow

\[ A = 0 \]
\[ B = 1.3478 \times 10^{12} \text{ Pa}^2/\text{kg} \]
\[ C = 2.1592 \times 10^{10} \text{ Pa}^2/\text{kg}^2 \]
\[ \rho_{ex} = 177 \text{ bar} \]

Figure 3 shows the initial distribution of the pressure and the temperature along the well. Based on this initial pressure and temperature distribution obtained from the Goldeneye CO\textsubscript{2} injection well, the CO\textsubscript{2} is in the gas phase in the first 400 m along the well and dense phase within the rest of the well depth. This initial condition is the same for all 3 ramp-up injection cases considered. In addition, a CFL condition of 0.3, \( \Delta t = 10^{-4}s \) and 300 computational cells were employed. In particular, this study considers linearly ramped-up injection mass flow rates from 0 to 38.5 kg/s in 5 minutes, 30 minutes and 2 hours. The varying ranges of CO\textsubscript{2} injection mass flow rates ramped-up with time from 0 to 38.5 kg/s at CO\textsubscript{2} feed pressure of 115 bar employed in this study is essential to understanding the optimum injection ramp-up duration.
The presence of CO$_2$ stream impurities is a well-established study and depending on the capture technology various amounts of impurities such as hydrocarbons, nitrogen, oxygen, hydrogen, carbon monoxide, hydrogen sulphide, argon and etc. can be present in the captured CO$_2$ stream (Wetenhall, Aghajani, et al., 2014). Table 2 shows the various CO$_2$ stream compositions according to post-combustion, pre-combustion and oxy-fuel capture technologies presented by Porter et al., (2015) is employed in this study CO$_2$ impurities simulations.

Table 2: CO$_2$ stream % compositions based on the various capture technologies

<table>
<thead>
<tr>
<th>Component</th>
<th>Post-combustion</th>
<th>Pre-combustion</th>
<th>Oxy-fuel</th>
</tr>
</thead>
<tbody>
<tr>
<td>CO$_2$ %v/v</td>
<td>(99.75)</td>
<td>(97.95)</td>
<td>(85)</td>
</tr>
<tr>
<td>Ar %v/v</td>
<td>(0.02)</td>
<td>(0.03)</td>
<td>(4.47)</td>
</tr>
<tr>
<td>N$_2$ %v/v</td>
<td>(0.09)</td>
<td>(0.9)</td>
<td>(5.80)</td>
</tr>
<tr>
<td>O$_2$ %v/v</td>
<td>(0.03)</td>
<td>-</td>
<td>(4.70)</td>
</tr>
<tr>
<td>CO ppmv</td>
<td>-</td>
<td>(400)</td>
<td>(50)</td>
</tr>
<tr>
<td>H$_2$S ppmv</td>
<td>-</td>
<td>(100)</td>
<td>-</td>
</tr>
<tr>
<td>H$_2$ ppmv</td>
<td>-</td>
<td>(20)</td>
<td>-</td>
</tr>
<tr>
<td>SO$_2$ ppmv</td>
<td>(20)</td>
<td>-</td>
<td>(50)</td>
</tr>
<tr>
<td>H$_2$O ppmv</td>
<td>(600)</td>
<td>(600)</td>
<td>(100)</td>
</tr>
<tr>
<td>NOx ppmv</td>
<td>(20)</td>
<td>-</td>
<td>(100)</td>
</tr>
<tr>
<td>CH$_4$ ppmv</td>
<td>-</td>
<td>(100)</td>
<td>-</td>
</tr>
</tbody>
</table>
These impurities are mainly identified to have significant impact on the behaviour of CO$_2$ during pipeline transportation and very significant changes in the thermodynamic properties of CO$_2$ stream were previously predicted (see Brown et al., 2013; Martynov et al., 2013).

- Effects of impurities on phase behaviour of CO$_2$ streams

Fig 4 shows the CO$_2$ streams phase envelopes calculated using the Peng-Robinson equation of state for the following cases (Wang et al., 2011): the CO$_2$ stream from oxyfuel combustion in a fluidized bed pilot plant combustor in Canmet Energy, containing 5.2 vol % O$_2$, 221 ppm CO, 1431 ppm SO$_2$ and 243 ppm NO; while the CO$_2$ stream from a zero-emissions process proposed by Canmet Energy, containing 1.05% CO, 1.7% SO$_2$, 0.32% H$_2$ and 690 ppm H$_2$S;

![Figure 4: Calculated phase envelopes for pure CO$_2$ and CO$_2$ mixtures (Wang et al., 2011)](image)

From Fig. 4 it can be seen that the critical temperature and pressure of the mixtures are quite different from that of the pure CO$_2$. N$_2$, O$_2$, Ar and H$_2$ show the greatest effect of increasing the saturation pressure of the liquid and decreasing the critical temperature. One extreme case is the mixture from oxyfuel combustion containing 5.8% N$_2$, 4.7% O$_2$, 4.47% Ar and other impurities at ppm level. The critical temperature decreases by about 10°C in comparison with that of pure CO$_2$, and the liquefaction pressure increases by over 50 bar. On the other hand, SO$_2$ results in a decrease in the saturation pressure and an increase of the critical temperature, as is expected from the high critical temperature of pure SO$_2$ (157.6°C). It can also be seen that low-concentration impurities, such as CO and NOx would not significantly affect the phase. Therefore, before the steady injection of CO$_2$ into the reservoir can be started, it is necessary to perform time-dependent operations to estimate important
wellbore pressure and temperature behaviours of the injected CO$_2$. Such operations include start-up, shut-in and emergency shut-down, which prove to be critical in the overall design of the well (Böser & Belfroid, 2013). Even after steady injection conditions are reached the well may be shut in and started up for maintenance of the upstream transportation system or other routine checks. It is therefore of paramount importance to be able to predict the behaviour of the CO$_2$, in terms of pressure and temperature along the full length of the well, to characterise and quantify potential risks (Li, et al, 2015).

**Results and discussion**

The results obtained following the simulation of the transient flow model for the injection of CO$_2$ with various stream impurities into highly depleted oil/gas fields are presented and discussed in details. Beginning at the top inlet of the injection well down to the bottom outlet into the reservoir, the pressure and temperature profiles are presented. Specifically, the pressure and temperature variations at the top of the well and the corresponding effects along the wellbore can be seen in the profiles.

Fig. 5 shows the variation in pressure with time at the top of the well for 5 mins ramp-up injection time. The start-up injection data shows a rapid drop in pressure of the incoming CO$_2$ at 115 bar to as low as 74.8 bar. Following the initial pressure drop is a recovery over the ramp-up duration until a steady state is attained.

![Figure 5: CO$_2$ wellhead pressure variation with time for 5 mins ramp-up injection](image)

Fig. 6 shows the variations in pressure with time at the top of the well for pure CO$_2$ and it mixtures. As can be seen, the pressure profiles of the mixtures are quite
different from that of the pure CO\textsubscript{2}. Oxyfuel and pre-combustion captured CO\textsubscript{2} mixtures show the greatest effect of pressure drop at the start of injection. The mixture from oxyfuel combustion containing 5.8\% N\textsubscript{2}, 4.7\% O\textsubscript{2}, 4.47\% Ar and other impurities at ppm level recorded the highest pressure drop of 69 bar from the inlet pressure of 115 bar. On the other hand, pre-combustion captured CO\textsubscript{2} stream containing 0.09 \% N\textsubscript{2}, 0.03 \% O\textsubscript{2}, 0.02 \% Ar and other impurities at ppm level showed a minimal drop in pressure. The results obtained in this study clearly show the impacts of stream impurities on the captured CO\textsubscript{2} at the injection well. Hence, minimising the level of impurities before injection is highly important to avoid higher pressure drop during the process.

Figure 6: Variations in pressure with time at the top of the well for pure CO\textsubscript{2} and it mixtures

Fig. 7 shows the variation in temperature with time at the top of the well for 5 mins ramp-up injection time. The start-up injection data shows a rapid drop in temperature following a corresponding pressure drop of the incoming CO\textsubscript{2} at 115 bar to as low as 74.8 bar. The temperature dropped rapidly from 277 K to 251 K within the first 120 sec. Following the massive temperature drop is a recovery over the ramp-up duration until a steady state is attained.
Fig. 8 shows the variations in temperature with time at the top of the well for pure CO$_2$ and mixtures. As can be seen, the temperature profiles of the mixtures are quite different from that of the pure CO$_2$. Oxyfuel and pre-combustion captured CO$_2$ mixtures show the greatest impact on temperature drop at the start of injection. The mixture from oxyfuel combustion containing 5.8% N$_2$, 4.7% O$_2$, 4.47% Ar and other impurities at ppm level recorded the highest temperature drop of 226 K from the inlet temperature of 277 K. On the other hand, pre-combustion captured CO$_2$ stream containing 0.09% N$_2$, 0.03% O$_2$, 0.02% Ar and other impurities at ppm level showed a minimal drop in temperature. The results obtained in this study clearly show the impacts of stream impurities on the captured CO$_2$ at the injection well. Hence, minimising the level of impurities before injection is highly important to avoid higher temperature drop during the process that may lead to ice formation with interstitial water molecules present in the mixture. Such low temperatures may also cause thermal shock on the steel leading to its crack and ultimate escape of injected CO$_2$. 

Figure 7: Variation in temperature with time at the top of the well for 5 mins ramp-up injection time
Figs. 9 and 10 respectively show the pure CO$_2$ corresponding results for the temperature and pressure profiles along the length of the well during the 5 mins ramping up process at different selected time intervals of 10, 100, 200 and 300 seconds. The pressure profiles show continues pressure build up along the wellbore during the 5 mins injection ramp up. On the contrary, the temperature profiles show a significant temperature drop for the 10, 100 and 200 s well profiles in comparison with the initial well temperature profile at 0 s. The well temperature profile at 300 s shows significant recovery approaching the initial well temperature profile. As can been seen in Fig. 10 the temperature profile along the injection wellbore shows an improve profile as the ramp up injection duration reaches 300 s compared with the 10, 100 and 200 s cases. In other words, operating a fast injection ramp-up is recommended to rapidly increase the injection flow rate with time and consequently minimise the drop in temperature along the wellbore.

This means that the presence of impurities in the CO$_2$ stream may further affect the temperature along the wellbore. For instance, the oxyfuel captured CO$_2$ stream with higher levels of impurities may impose temperatures below 0 °C on the wellbore down to the bottom of the well. The effect of such low temperatures on the injection system is highly significant and accounted as a critical factor for safe injection of CO$_2$. Based on the fact that there is a possibility of interstitial water molecules present within the wellbore during injection, the formation of ice is likely and may pose significant safety risks.
Figure 9: Pure CO₂ wellbore pressure profiles at selected time intervals

Figure 10: Pure CO₂ wellbore temperature profiles at selected time intervals
Conclusion and future work

This study has led to the development and testing of a rigorous HEM for the simulation of the highly-transient multi-phase flow phenomena taking place in wellbores during the start-up injection of high pressure CO\textsubscript{2} streams into depleted gas fields. In practice, the model developed can serve as a valuable tool for the development of optimal injection strategies and best-practice guidelines for the minimisation of the risks associated with the start-up injection of CO\textsubscript{2} streams with various impurities into highly-depleted gas fields. Specifically, we have shown the impacts of CO\textsubscript{2} stream impurities on wellbore pressure and temperature profiles to enhance safe injection. However, previously existing knowledge could not provide solutions to the stream impurities problems that will be inevitably encountered. The results obtained from the present work are expected to have significant applications or implications to all CO\textsubscript{2} storage operations.

It is critically important to bear in mind that the above results are not universal. On the contrary, they are only based on the case study investigated on a highly depleted gas field. Each injection scenario must be individually examined in order to determine the likely risks. However, in this study we have developed the computational tool needed to make such assessment.

The experience gained during this work has opened to us new interesting areas of research, which would be worth investigating. We highlight here two main potential developments. Firstly, an appropriate two-fluid model with flow-regime-dependent correlations will have to be developed and analysed to the full impacts of the stream impurities. Secondly, it would be worth considering a coupling between the HEM in the well and an appropriate Darcy solver for all the reservoir variables. In so doing, we would be able to take into account more directly those properties of the reservoir (pressure, porosity, permeability, etc.) which vary in time as well and depend on the actual exploitation history of the reservoir under investigation.
References


