1. INTRODUCTION

1.1 Background Information

The eminence for reducing greenhouse gas emissions from the environment urged societies to devise means towards CO_2 capture and storage. Amongst such means geological storage is seen so far as one of the major short to medium-term alternatives (Bielinski, 2007, Rebscher and Oldenburg, 2005, Pruess, 2005, Benson and Cook, 2005).

The opportunities found in enhancing recovery of oil in oil reservoirs have led to intensive research on CO_2 properties that directly or indirectly affect injection process in general and flow in wellbore in particular. In order to get CO_2 in the reservoir being it for storage or for enhancement of hydrocarbons recovery, the fluid must transit through the well from the surface. In this respect, it is important to understand the behavior of the fluid on its way from the wellhead to the bottom of the borehole. This requires thorough investigation, which ideally should involve experimental and/or field measurements of most important parameters affecting the fluid behavior. In the absence of such measurements, modeling has proved over the past to be a powerful tool to estimate within experimental uncertainty, parameter which would otherwise be cost prohibitive to measure.

Models can roughly be grouped into two categories with respect to the approaches to solution: analytical and numerical models. Numerical models are complex. They incorporate as many details as possible. Therefore the number of underlying assumptions would be reduced. Conversely, analytical models are simpler. As a consequence, more assumptions would be considered in their development.

The solution to numerical models is obtained by approximation methods such as finite difference, finite volume or finite element. Such approximations would incorporate errors in the final solution. The magnitude of these errors usually depends on the method, the step sizes, the algorithm type and the size of the problem.

The analytical methods get the exact solution but are seldom appropriate for complex problems. The problem usually needs to be simplified with realistic assumptions for the solution to be found. An important issue is that sometimes, assumptions may over-simplify the problem and fail to capture its most important facets.

The development of analytical models to rigorously predict the temperatures and pressures of CO_2 along an injection well forms the subject of this dissertation.

The ensuing paragraphs present the detailed objectives and the scope of this work. They are followed by the description of the methodology used in attaining these objectives. Subsequent sections provide a review of the literature on fluid-flow in a wellbore in general and CO_2 flow in particular. The later sections firstly present the model development process. It is followed by the model validation part. In this part the predictions of the models are tested against field measured data and sensitivities to injection conditions and injection time are performed. The work is ended with general conclusions that wraps up the findings and with some recommendations for further works.

1.2 Objectives and Scope

Brill and Mukherjee (1999) made and extensive review of fluid flow in wells. They reported that many models have been proposed for single and multiphase flow prediction. Only few of them focus on gas injection in general and on CO_2 injection in particular. Conversely, the literature is very verse with empirical and mechanistic models for two and single phase upward flow of petroleum fluids in wells. The empirical and mechanistic models require modeling of flow regimes to capture multiphase flow behavior. The approaches to solution consider a one-dimensional multiphase flow problem and are generally based on fully implicit numerical schemes associated with well segmentation. Holmes et al (1998) recognized that these approaches are appropriate only when the functions are continuous and differentiable over the entire range of variables. They went on to propose two modeling approaches that overcome this discontinuity problem. These are:

1. The homogenous model: it assumes all phases to flow with the same velocity. Consequently, the properties of the fluid are estimated as weighted average of the values of each property from all the phases.
2. The Drift flux model: it takes into consideration the difference in velocity amongst the phases. As such, it provides a means to account for the slip between these phases.

Most of the existing codes for prediction of flow in wells have been developed with respect to petroleum fluids. As such they do not consider phase transition along the pipe nor do they model evolution of fluid's temperature and that of the surrounding rock with time. Paterson et al (2008) recognized phase transition as an important issue for CO_2 flow in geological formations. This issue becomes more re-sounding in offshore applications, where external temperature gradient in the sea is far different from the atmospheric and the geothermal gradients. Furthermore, these codes solve pressure and enthalpy balance equations with numerical methods. These methods would most often add errors to the results.

Some authors have proposed analytical solutions to pressure and enthalpy balance equations along the well. Amongst these, the solution of Hagoort (2005) is worth mentioning. Works have also been done in other branches of engineering and in other aspects of mining and petroleum engineering, on analytical solutions to problems in heat exchange and temperature propagation in composite solids and rocks. These solutions could be adapted to predict the evolution of temperature of fluid in the well and that of the surrounding rock as a function of injection days. Worthy to mention are the works of Eppelbaum and Kutasov (2006) on temperature drawdown well testing and those reported by Coulson and Richardson (1996) on heat transfer through composite walls.

In the light of the forgone points, the major objective of this work is to develop a rigorous procedure that is based on analytical solutions to pressure and enthalpy balance equations in order to accurately predict pressure and temperature of CO_2 in a well during injection into a geological formation as a function of depth and time. In achieving this main objective the following sub-objectives are also to be achieved:

1. Modeling phase transition and its associated effects on temperature and pressure in the well.
2. Revisiting existing analytical solutions to problems in heat exchange and temperature propagation in composite walls and rocks and adapting them to model the fluid temperature in the well and the propagation of temperature in the surrounding rock with time and with depth.
3. Improving the prediction of thermodynamic and transport properties of CO_2 in the well
4. Developing a simulation tool that can accommodate wellbores of varying diameters, varying deviation angle and non-uniform tubing string.
5. Developing a simulation tool that can be used to estimate thermal conductivity, thermal diffusivity of the surrounding rock at specified depths whenever temperature measurements are available. As such the codes can accommodate layered formations with different thermal properties and various geothermal gradients.

The model focuses on pure CO_2. Therefore a single phase solution is essentially adopted. However two-phase flow is captured through the homogenous fluid model. This neglects the effect of slip between flowing phases by considering fluids' properties to be the weighted average of the properties from the two phases.

1.3 Methodology

Hagoort (2005) proposed an analytical solution to temperature in a gas production well. He recognized that this solution if combined with an appropriate solution to pressure could form the building block for a more rigorous general prediction of temperature and pressure in gas production well. Recognizing the pertinence of this point made by Hagoort and based on the evidence he brought in validating his model, this work has followed his recommendations and some of the steps used in developing his model. As such analytical solutions to temperature and pressure have been developed and combined with accurate methods to estimate thermodynamic and transport properties to form a procedure to rigorously predict CO_2 pressure and temperature in an injection well.

Hagoort further rearranged the pressure and temperature equations to isolate dimensionless numbers in order to improve the transparency and control of his solutions. The same approach has been used in this work. Analogous dimensionless numbers have been isolated with respect to injection situation. They do not only improve the transparency and control of the solutions but they also make it easier to analyze the results and to detect user-related errors. This forms one of the innovations in this work.

Four solutions to temperature and one solution to pressure have been developed. The main temperature solution is the most rigorous in estimating the temperature along the well. It is non-adiabatic and as such it takes into account the temperature effects caused by compression/expansion of the fluid in the well and those related to the heat exchanged between the fluid and the surrounding rock. In this way the wellbore and the rock are assumed to form a heat exchanger with composite wall between the heat source and the heat sink. The composite wall is made up of the wellbore components (cement, casing, annulus and tubing).The three other temperature models are the adiabatic model, the geothermal model and the isothermal model.

The adiabatic model assumes that the well is perfectly insulated from the surrounding rock. Consequently only the effect of compression and/or expansion influences the temperature of the fluid in well.

The geothermal model assumes that the temperature of the fluid is equal to that of the surrounding rock at each depth. This situation would be approached whenever the flow rate is very low to allow longer contact time between the fluid and tubing surface.

The isothermal model assumes that the temperature is constant along the well. It would be approached in a horizontal well when inlet temperature is equal to geothermal temperature and frictional pressures losses are sufficiently small not to cause significant temperature drop.

In arriving at the temperature solutions and at the pressure solution some other innovative approaches were necessary not only to improve existing models but also to enable using them in the solution procedure. The major innovations that significantly contributed to the rigorous solutions in this work are the following:

1. Development of a workflow to use high accuracy multiparameters equations of state to predict CO_2 thermodynamic and transport properties along the well. This required creating runtime tables from which the properties are read during simulation.

2. Revisiting Willhite's procedure to calculate the overall heat transfer coefficient (OHTC) in the wellbore (Willhite, 1967). In this procedure the OHTC is expressed as a function of the outer surface area of a characteristic area which could be the outer area of the tubing (for injection through tubing) or inner area of the casing (for injection through annulus). This choice neglects the influence of the surface areas of other components and might result in a serious underestimation of the heat transfer area. This work capitalizes on the analogy between the wellbore and a heat exchanger with composite wall material discussed by Coulson and Richardson (1996) to estimate the OHTC as a function of an overall heat transfer area. The overall heat transfer area is calculated as the log average of the surface areas of the wellbore components from the tubing to the interface between the rock and the cement.

3. Adapting an innovative model for temperature drawdown well testing to predict temperature propagation in rock at any injection time being it early or late. This has been possible by assuming the flowing fluid to be an infinite cylindrical heat source or heat sink and by making analogy between the thermal contact resistance and the overall heat transfer coefficient. This is very important because it enables to estimate thermal conductivity and thermal diffusivity of the surrounding rock based on the measured temperature of the fluid in the well.

4. Revisiting the marching algorithm proposed by Brill and Mukherjee (1999 , P. 26) and implementing with analytical solutions to arrive at accurate estimates of pressure and temperature along the well. This involved including in the original algorithm the validation criterion proposed by Economides et al (1993, P. 145) for pressure in a gas well. This work also uses this criterion to validate temperature. The criterion requires that the relative difference between the z-factor at the inlet of a segment and that at its outlet should not exceed 0.1%.

The equations for pressure and temperature calculation are coupled and solved simultaneously to arrive at the solutions for pressure and temperature along the well. The pressure calculation is based on the extended Bernoulli's equation. It accounts for frictional pressure losses and neglects kinetic energy effects. The temperature of the fluid along the well is estimated with the enthalpy balance equation. It considers heat transfer between the fluid and the surrounding as well as the heating or cooling resulting from phase change and the heating as result of compression. The heat exchange with the surrounding follows the approach proposed by Ramey (1962) and revisited by Hagoort (2004). It assumes steady state heat flow through the wellbore components (cement, casing annulus and tubing) and transient heat flow through the formation. The heat flows through the wellbore components as a function of the overall heat transfer coefficient and the overall heat transfer area. Its propagation in the surrounding rock is controlled by a time function based on the thermal diffusivity equation in rocks.

Because of the inadequacy of the Ramey's time function to model heat propagation in the formation for times less than one week, this work has adapted the models proposed by Eppelbaum and Kutasov (2006)'s in analyzing temperature drawdown during well testing to derive a time function applicable to all times (earlier or later than one week). It assumes the fluid in the well to be an infinite cylindrical heater and draws on the analogy between the thermal contact resistance and the overall heat transfer coefficient.

Recognizing that the capability of a code to predict pressure and temperature of a fluid in a wellbore also depends on its ability to properly model thermodynamic and transport properties of the fluid, these properties are estimated with reference equations of state for CO_2 in order to obtain improved accuracy. The Span and Wagner (1996) equation is used for the calculation of density and other thermodynamic properties. The equations of Fenghour et al. (1998) and Scalabrin et al. (2006) are used for the calculation of viscosity and thermal conductivity respectively. These equations are computationally time-intensive. As such to avoid implementing them directly in the codes they are used to generate runtime tables from which the properties are read during simulation. The tables are generated in temperature and pressure ranges of 250 to 450 K and atmospheric pressure to 400 bar respectively. The simulator reads prevailing temperature and pressure in the wellbore and extracts the corresponding properties from the tables. Linear interpolation is used for values that fall in between those tabulated.

The solution to the models is implemented through simulation codes developed with the Visual Basic.Net programming language on the Microsoft Visual Studio platform. The codes are encapsulated in a user-friendly graphical user interface. This interface ensures easy input and output of the data.

The implementation of the marching algorithm enables to minimize the errors related to the use of average values of thermodynamic and transport properties in analytical solutions to pressure and temperature in the well. The algorithm consists of dividing the wellbore into segments of which lengths are determined by the above-mentioned validation criterion on temperature and pressure to ensure high accuracy in pressure and temperature solutions. Whenever the criterion is violated, the segment's length is chopped and calculation is repeated so on and so forth until the criterion is obeyed. A consequence of the segmentation of the well is the establishment of a computational loop which is repeated from the inlet to the outlet of the pipe.

The validation of the models and the procedure has been performed firstly by comparing the predictions of temperature and pressure with measured values from two injection projects in saline aquifers. Secondly same comparison has been made with measured data from a CO_2 production well to confirm the robustness of the solutions. Thereafter a comparison of the predictions of the main temperature model (non-adiabatic) to those of the three other models (geothermal, adiabatic and isothermal) is performed. And finally the sensitivities of the pressure and temperature predictions to injection parameters (wellhead temperature, wellhead pressure, injection flow rate and tubing diameter and inner roughness) and injection time is also analyzes. The aim of the temperature models' comparison and that of the sensitivity analysis is to extensively test the procedure for the predictive capabilities and agreements with general theories of fluid flow in cylindrical pipes and heat transfer into a heat exchanger with a composite wall.

2. LITERATURE REVIEW

The literature is rich in models for predicting single and multiphase flow in wellbores. These models differ from their nature and their underpinning assumptions. Specific applications to CO_2 have not been extensively reported. Notwithstanding, many works have been documented on the estimation of the properties of CO_2 that play important roles on its state and behavior along a pipe in general and in a wellbore in particular. The following paragraphs will first review major works on fluid flow in pipes with an emphasis on the developments with respect to the estimation of pressure and temperature along the wellbore. Thereafter they will highlight important contributions towards the prediction of thermodynamic and transport properties of CO_2.