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Temperature transient analysis models and workflows for vertical dry gas wells

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ABSTRACT

High resolution temperature sensors in downhole completions in the last decade has made high quality, transient temperature data available suitable for both qualitative and quantitative analysis. This data availability has stimulated the development of accurate models for the quantitative analysis of temperature transients. There are only a limited number of publications in the area of temperature transient analysis (TTA), the majority of which are limited to liquid production at the wellbore. One reason is that the compressible nature of gas results in a more complex mathematical problem when compared to that for incompressible liquids. The second reason is that more data is available from high precision, downhole temperature sensors installed in oil wells than from gas wells.

This work is the sequel to previous work that derived an analytical solution for the transient sandface temperature of a vertical dry gas producing well (Dada et al. 2017). We discuss the derivation of interpretation models and workflow for estimating the flow characteristics of a dry, gas producing well from transient temperature data. The developed workflow linearizes the analytical equation describing flow into the well from a dry, gas reservoir. It has been successfully applied to both a synthetic and a real well production data set.

The application area of the developed analytical solution is discussed. The two most important of the simplifying assumptions that affect the results concern (1) the impact of a gradual change in the flow rate and (2) non-Darcy inertial flow. Guidelines are developed to determine when the impact of a gradual flow rate change has died away. It was also concluded that the non-Darcy effect had little impact on the transient temperature log-time derivative, the key plot in TTA.

The developed TTA workflow has therefore been validated for many practical TTA applications, as shown by its successful application and validation against conventional pressure transient analysis (PTA) for both synthetic and real-well data sets. TTA's unique ability to estimate the radius and permeability of a low permeability (formation damage) zone around the wellbore was also validated. This important parameter is not available from PTA. This work represents a further important step towards the development of a comprehensive PTA/TTA data analysis framework for multi-phase production wells.

1. Introduction

The regular determination of a well's inflow performance is one of the key well surveillance tasks in production engineering. The well inflow performance depends on the permeability-thickness (kh) product contacted by the completion and the condition of the near-wellbore zone. Estimation of the permeability-thickness (kh) and the skin values is one of the most important results from well test analysis.

Another important task of the production engineer involves monitoring the produced fluid phases and their flow rates from the combined well-reservoir system (well production allocation) as required for production optimisation, reservoir management and reporting of well reserves. Flow rate estimation involves quantifying the total volume and phase fraction of produced fluid, while production allocation determine the fraction of the total production contributed by each reservoir zone (or layer). Several methods have been developed for flow estimation, including production logging, permanent downhole flow meters, pressure drop measurement across flow constrictions, multi-rate tests, virtual flow-metering

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and thermal modelling (both steady state and TTA) (Konopczynski et al., 2003). Thermal modelling has great potential as a low-cost, low-risk method of obtaining this information. Further, the temperature signal propagates at a much slower rate than the traditional pressure signal. This gives TTA the unique advantage of being able to accurately probe the near-wellbore zone or profile the reservoir/inflow properties along the production interval.

High resolution downhole temperature sensors that can resolve small temperature changes for well surveillance purposes were developed in the 1970s (Completions, 2008), with fibre optic technology extending the range of possible completion designs. The measurement required for TTA are now available at a reasonable cost.

However, accurate thermal models are essential when predicting the transient temperature change in the reservoir and at the sandface, during TTA. This thermal model is the basis for all analytical or numerical solutions for TTA. It is usually a partial differential equation (PDE) which describes the relationship between the fluid and rock properties and the pressure and temperature changes in the porous media. Derivation of the thermal model used to estimate the transient sandface temperature can be found in e.g. (Sui et al., 2008b), which is itself based on the model by (Bird et al., 2007). This thermal model shows that the measured transient temperature change in porous media is a function of the fluid expansion, Joule-Thomson effect, heat convection and conduction. This, or similar models, were used by (Muradov and Davies, 2011), (Duru and Horne, 2010) and (Ramazanov et al., 2010) to estimate the transient sandface temperature analytically or numerically. The authors obtained realistic estimates of sandface temperature. (Muradov and Davies, 2013) and (Duru and Horne, 2010) compared their results obtained from analytical and/or numerical solutions (based on this model) with real well data.

Numerical solutions for TTA are normally used directly in inversion workflows for characterizing a formation, allocating flow rate or carrying out a near wellbore analysis. They are usually case specific, and do not produce a general solution while the analytical TTA solutions are faster and more general, as well as providing valuable insights into the problem. Table 1 lists some of the TTA publications along with their area of application.

The estimation of zonal production rates, formation properties and the identification of the produced phases requires inversion of the forward TTA solution. This inversion is easy and fast for analytical solutions; but is slower for numerical solutions as it requires some form of optimization to minimize an objective function. (Sui et al., 2010), for example, performed the inversion by nonlinear regression using the Levenberg-Marquardt algorithm. Another advantage of an analytical solution for a system is that it explicitly describes the nature of the system's behaviour and how its parameters relate and affect the system's response. However, most of the analytical solutions and inversion methods developed to-date refer to liquid producing wells. This paper reports the work carried out to characterize a dry gas producing reservoir by development of inversion workflows for TTA data.

We previously developed analytical solutions for predicting the transient sandface temperature in a vertical dry gas producing well (Dada et al., 2017). We now use this solution for characterizing a reservoir; i.e. by determining the permeability-thickness product and skin. This method is used in conjunction with the well-developed PTA workflow. The combination of PTA and RTA (Rate Transient Analysis) is further used to validate the results obtained from TTA of a real-well data.

The following sections show how we linearize the analytical solution (in log-time scale) for vertical dry gas producing wells (Dada et al., 2017). This linear form of the equation is then used for characterizing the reservoir and analysing the near wellbore reservoir properties. The limits of our method stemming from our assumption of laminar flow are discussed. Our method was further successfully applied to both synthetic and real case studies, showing that it can be applied to many field situations.

2. Analysis of the problem

Eqn. (1) is the analytical solution for the sandface temperature of a vertical dry gas well producing at a constant rate after a period of shut-in (or a step change in the flow rate). Eqn. (1) was derived for a dry gas well producing at a constant, non-zero rate and with an infinite acting boundary condition. Appendix C provides a brief description of how the solution was derived and the assumptions used in its derivation.

$$T_{wb}(t) - T_i(t) = \varepsilon\left[P_{(r=r_T)} - P_{wf}(t)\right] + \eta^* e^{(-2\alpha U_o)}\left[P_{wf}(t) - P_i\right] \tag{1}$$

(The terms are listed in the Nomenclature at the end of the paper).

Note: Eqn. (1) is normally used to describe a “drawdown” test where the production rate is instantaneously increased from one constant value to a second, higher value. The derivation often assumes a zero initial rate; describing the case when well production starts after a shut-in. However, the solution is also applicable to any rate change as long as the initial temperature term in Eqn. (1) is accurate and the final flow rate is non-zero. This covers a well being placed on production and a positive or negative flow rate change, as long as the well is **not** shut-in. The full analytical solution for a well shut-in, or “build-up” test, is not currently available.

Gas properties are strongly temperature and pressure dependent. However, their **combinations** that appear in Eqn. (1) may be assumed to be constant (Dada et al., 2017) for thermal analysis. They are estimated at the initial temperature and the average pressure “P_{avg}” (midway between the initial wellbore pressure and the final, stabilized wellbore pressure). *Note this assumption is not valid for the equivalent* ***pressure*** *solution for a gas well since gas properties used in the pressure model are very sensitive to the changes in pressure observed in field application. That is why an accurate, classical gas well pressure solution is used in this work [pressure is part of thermal Eqn. (1)] as far as the pressure model is concerned.*

Eqn. (1) shows that the temperature change is a combination of the Joule-Thomson effect (term 1 on RHS) and the transient fluid expansion (term 2 on RHS) plus the heat convection term due to the resulting temperature gradient. Also, $2\alpha U_o \ll 1$ for most practical purposes, therefore $e^{(-2\alpha U_o)} \approx 1$.

The above allows Eqn. (1) to be reformulated as:

$$T_{wb}(t) - T_i(t) = \varepsilon\left[P_{(r=r_T)} - P_{wf}(t)\right] + \eta^*\left[P_{wf}(t) - P_i\right] \tag{2}$$

The pseudo-pressure method developed for gas wells by (Al-Hussainy et al., 1966) was used to obtain the pressure solution. A linear pressure - pseudo-pressure relationship {Eqn. (3)} is sufficiently accurate for our well production conditions. It can be combined with the line source solution and the logarithmic approximation for an infinite acting reservoir producing at a constant rate {(Eqn. (4)) (Al-Hussainy et al., 1966)}.

$$P = A + B\psi \tag{3}$$

$$\psi = \psi_i - \frac{\psi_i Q_d}{2}\left[\gamma + ln\left(\frac{\phi\mu c r^2}{4\lambda k t}\right)\right] \tag{4}$$

Where “γ” is the Euler-Mascheroni constant.

The constants “A” and “B” in Eqn. (3) are case-specific and