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Thermal wellbore strengthening through managed temperature drilling – Part I: Thermal model and simulation

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ABSTRACT

This paper is the first part of a two-part series introducing a new and innovative managed temperature drilling technique for strengthening the wellbores of challenging oil and gas wells. This technique relies on heat generation within the borehole to increase the effective fracture gradient of near-wellbore zones in oil and gas wells. By releasing heat at exactly the right time and at the right location, the temperature in a near-wellbore zone can be raised, which in turn raises thermal stresses in this zone. This results in "thermal wellbore strengthening", i.e. an increase in near-wellbore fracture initiation and propagation pressure that can be exploited to prevent or minimize induced mud losses during drilling, cementing and completion operations. As shown in Part II of this series, the heat-release is preferably achieved in a delayed fashion through the use of exothermic "heat-releasing" particles that are circulated to the zone(s) of interest in a dedicated carrier fluid.

Part I describes a new computational thermal model for the proposed technique. Using finite volume techniques for an axisymmetric cylindrical geometry including a drillstring/workstring with internal and external fluid spaces, a casing string and a cementing layer (if present), and the rock formation, the model calculates the near-wellbore formation temperature as well as annulus and drill string temperature when a time-dependent and location-dependent heat generation source is acting. Model validation was conducted by comparing the simulation results from the model to analytical solutions as well as results obtained with a commercial software package for simplified cases (1D along the wellbore) with no heat source. Subsequently, near-wellbore temperature distributions were calculated for varying heat generation rates and fluid circulation times, and passed on to a geomechanical model to estimate the magnitude of the thermal strengthening effects on the fracture gradient. Results show that meaningful increases in near-wellbore stress can be obtained by the technique.

The thermal wellbore strengthening technique, supported by the new thermal model described here, can be used to minimize lost circulation events and associated well trouble time and cost during drilling, cementing and completion operations, and may be particularly suited for wells with low drilling margins such as (ultra-) deepwater wells.

1. Introduction

A wellbore of an oil or gas well may pass through several geological formations with varying geo-mechanical conditions, with variations in the values of in-situ stress, pore pressure, rock strength and failure parameters, etc. Different formations will have differing fracture gradients (FG), and thus differing susceptibility to induced fracturing during well construction operations. Low fracture gradients are especially problematic for wellbores that intersect pressure-depleted zones. The fracture initiation pressure (FIP) and fracture propagation pressure (FPP) are generally lower in such depleted zones due to reduced minimum horizontal stress values. In addition, in deep offshore wells, the mud window (the difference between the fracture pressure and either pore pressure or the mud pressure required to prevent shear failure at the wellbore wall, whichever of the two is higher) is generally narrower due to a low overburden stress associated with a large water column and abnormal pore pressures (generated by such mechanisms as under-compaction, clay diagenesis, pore fluid thermal expansion etc.). As a result, induced wellbore fracturing in depleted zones is a particular concern in deepwater wells.

When the fluid pressure in the wellbore is sufficient to either re-open existing fractures or create new fractures in a rock formation, wellbore fluids such as drilling fluids, cementing fluids, completion fluids and the like can be lost in large quantities. This lost circulation

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phenomenon is a profound operational problem, not only because of the replacement costs of the lost fluids, but also because of rig downtime required for remediation. Such non-productive time (NPT) can substantially increase the capital cost of an oil and gas well, particularly in deepwater operations. Moreover, there may be negative consequences for longer-term well integrity associated with lost circulation due to failed cement jobs, causing poor zonal isolation and compromised barriers that may allow formation fluid flow to surface.

The near-wellbore rock stresses, and thereby the fracture gradient, are sensitive to the temperature in the wellbore. Stress variations due to temperature change are often ignored, either because they are poorly understood or because the variations in near-wellbore temperature are small. However, significant changes in the near-wellbore temperature can have a substantial effect on the stress distribution around the wellbore. This has been recognized by several authors, who have noted the effects of wellbore cooling through mud circulation on lowering the near-wellbore tangential stress, thereby inadvertently leading to lost circulation events (see e.g. Gonzalez et al., 2004; Hettema et al., 2004; Algu et al., 2007).

The near-wellbore effect of a temperature difference ΔT between the formation and the wellbore fluid on tangential stress $\sigma_{\theta\theta}$ is given under steady-state conditions by (see e.g. Zoback et al., 2003),

$$\sigma_{\theta\theta}^{\Delta T} = \frac{\alpha_t E \Delta T}{(1-\nu)} \tag{1}$$

where α_t, E and ν are the thermal expansion coefficient, Young's modulus and Poisson's ratio of the rock formation respectively. The temperature difference ΔT is negative for cooling of the wellbore wall (wellbore temperature lower than in-situ formation temperature), whereas it is positive for heating of the wellbore wall (wellbore temperature higher than in-situ formation temperature). In the latter case, the near-wellbore tangential stress, and thereby fracture initiation and propagation pressure, can be raised by heating of the rock formation.

In order to estimate the effects of a heat generation process in terms of near wellbore temperature increase, as well as the drilling fluid temperature in the wellbore, a new heat transfer model was needed. None of the currently available analytical models or commercial software packages can handle a time-dependent and location-dependent heat source in the wellbore. This new advanced heat transfer model accompanied with a geomechanics model allowed us to estimate the increase in effective fracture gradient due to near wellbore temperature increase, as described below.

2. Background

There appears to be a clear oil and gas industry need for active wellbore strengthening methods that are effective and easily deployable. Several methods and techniques have been proposed and implemented in the past two decades to strengthen the wellbore using fracture plugging with particles (for a review, see e.g. van Oort and Razavi, 2014). Several experimental investigations were also conducted to investigate the effect of important parameters on plugging up the fractures with lost circulation materials (e.g. DEA 13, 1988; Dudley et al., 2000; Razavi et al., 2015, 2016). However, no method to date has incorporated active strengthening through thermal means with a simple and cost-effective system. The mechanism of deliberately elevating the fracture gradient through thermal means was recognized as an option for drilling and cementing high-complexity Mars B/Olympus development wells (see Grant et al., 2014; van den Haak, 2014) which intersect highly depleted reservoirs to develop virgin-pressured deeper horizons in the Mars/Ursa Basin in the Gulf of Mexico. This work, however, did not specify either a model to quantify the heating and associated strengthening effects or a practical method for implementing thermal wellbore strengthening (TWBS). These are the subjects of Part I and Part II of this paper series respectively.

The history of heat transfer modeling in oil and gas wells dates back to the 1960s. Pioneering studies by Ramey (1962) and Raymond (1969) on heat transfer analysis of drilling wells are the foundation for later studies. Holmes and Swift (1970) developed an analytical mathematical model that can be used to predict the mud temperature in the drill pipe and annulus while drilling a well at any depth, based on the steady-state equation for the heat transfer between the fluids in the annulus and the fluids in the drill pipe. Schoeppel and Bennett (1971) developed a numerical simulation of borehole and formation temperature distributions. The method was used to numerically model the non-steady state temperature distributions in a circulating drilling fluid and the surrounding formation. Marshall and Lie (1992) provided a finite difference approach, simultaneously solving all the heat transfer equations. Predictions of the bottom-hole and return temperatures from this model were shown to closely agree with the available field data. Kabir et al. (1996) estimated fluid temperature in the flow conduits of a well (i.e. drill pipe or tubing, and the annulus) to ascertain the fluid density and viscosity, and in turn to calculate the pressure-drop or the maximum allowable pumping rate for a number of well operations. Steady-state heat transfer was assumed in the wellbore while transient heat transfer took place in the formation. Aadnøy (1999) developed an analytical model describing the energy balance in a circulating well. Input of energy due to rotation of the drillstring and pumping of the mud were included. Finally, Chen and Novotny (2003) developed a finite difference method to determine the bottom-hole circulating temperature for proper design of cementing slurries.

All the existing analytical models or commercial software only provide 1D temperature profile along the wellbore (not the formation temperature profile) and cannot handle the time-dependent and location-dependent heat generation term (such as generated by a time-delayed chemical reaction, see Part II, van Oort et al., 2018). However, a more sophisticated model is essential to estimate the elevation of near wellbore fracture pressure due to thermal stress of the time-delayed chemical reaction, which encouraged us to develop the model presented here. Consequently, by applying this model, it is possible to calculate the transient temperature distribution for various heat generation rates of different exothermic chemical reactions or any other time- and location-dependent heat source acting in the wellbore. The temperature increase data at various locations within the formation was then used to calculate the thermal stresses and assess increases in fracture pressures. This advanced heat transfer model thereby forms the backbone for design analysis of managed temperature drilling (MTD) operations.

3. System design and modeling

3.1. Exothermic system selection

The following provides a brief introduction of the heating system used for the MTD-TWBS technique. The only mechanism suitable for heating at great well depths with current state-of-the-art technology (see Part II, van Oort et al., 2018 for discussion) was considered to be an exothermic (heat-releasing) reaction of additives in a water-based fluid environment. This exothermic reaction could be generated using well-known oilfield chemicals and could be delayed using techniques borrowed from the pharmaceutical industry to allow time for heat-releasing particles to be circulated to the location of the rock formations of interest.

After careful consideration of possible exothermic reaction candidates, a preference was given to simple (dis-)solution reactions of common salts in water (see Table 1). The most promising candidates proved to be the anhydrous chloride and bromide salts of magnesium ($MgCl_2$ and $MgBr_2$) and calcium ($CaCl_2$ and $CaBr_2$), additives that already find regular application in drilling and completion operations, e.g. being used extensively in completion brine systems. Ultimately, $MgCl_2$ and $CaCl_2$ were selected in a first approach to chemical system development. For a more comprehensive and detailed report on system