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Prediction analysis of downhole tubing leakage location for offshore gas production wells

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ABSTRACT

Industry experience has shown that downhole tubing leakage is the most challenging issue resulting in sustained casing pressure in natural gas production wells. This article presents a novel tool based on pressure difference and probability distribution for predicting the tubing leakage location for an offshore gas production well with sustained casing pressure. Combined with the formation information, well structure, annular fluid level and dynamic production parameters of a gas well, the model of pressure difference between tubing and production casing annulus is established. However, these pressure-based predictions suffer from various sources of uncertainties, such as the variations in reservoir conditions, and measurement errors. Bayesian inference is introduced to handle these uncertainties in leakage location forecasting effectively. Dynamic confidence intervals under two kinds calculation modes are applied to calculate the leakage depth within a certain range. The probabilistic distribution of leakage location is statistically predicted under different wellhead pressure difference using Monte Carlo simulation. A case study on a specific offshore gas well with the field data is presented to illustrate the feasibility of the proposed method and to demonstrate that the downhole tubing leakage location prediction contributes to the safety and integrity management of offshore production wells in an economical and convenient way.

1. Introduction

In a steady-state production gas well, the wellhead pressure of casing annulus should be zero after a small volume of fluid caused by thermal expansion effects has been bled. If it rebuilds to the same pressure level when the needle valve is closed, the casing is considered to be exhibiting sustained casing pressure (SCP) [1]. SCP may be prone to pose a serious threat to well integrity and production safety without being well handled. The well integrity failures and other problems have been investigated in [2], mostly accounting for 18% in 406 Norway's offshore wells. High annulus pressure will cause a collapse failure of casing [3] or liner [4]. If the casing with SCP fails, the next outer casing string generally would not be able to withstand the pressure, which may result in serious accidents even with huge economic losses. When the measured wellhead pressure is greater than maximum allowable wellhead operating pressure, the casing pressure needs to be managed on a case-by-case basis [5]. Downhole tubing leakage is a major contributing source which is responsible for SCP in the tubing-production casing annulus, with the risk of extra production disturbance and wellbore integrity failure. Therefore, downhole tubing leakage prediction is necessary to promote integrity management of offshore gas production wells in a safe way.

Many theoretical models have been developed for SCP prediction and annulus pressure calculation. These models mainly focus on the gas migration behaviors in the cement and the mud of annulus, with some influences on the annulus pressure behavior considered, such as wellbore temperature, formation pressure and casing deformation [6,7]. The typical mathematical model has been developed by [1] to predict wellhead pressure in casing-casing annulus with limitation of application in tubing-production casing one. Yang et al. [8] have established the model for the interactions among the casing-cement-formation system, taking into account deformation of the casing. A semi-steady state model has been presented to predict annulus pressure buildup considering temperature effects and other factors in subsea wells[9]. Based on the pressure prediction model, the risk of wells with SCP can be quantitatively estimated by utilizing the early-time pressure buildup data [2]. A pressure-balance-based approach has also been proposed to determine temperature and pressure distributions of tubing and annulus fluid [10].

Conventional downhole leakage is detected by logging techniques,

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testing and analytical approaches. Ultrasonic logging method for casing leak detection has been developed by an ultrasonic signature [11]. Temperature logging [12] and the temperature analytical thermal model [13] have been presented for wellbore leakage of carbon dioxide with large leaks. Pulse testing in frequency domain has been used to detect and characterize the location and geometry of the carbon dioxide leak [14]. The acoustic detection technology based on Fourier transform has been applied to gas flux detection [15]. Tracer technology has been also used in detection of dam leaks [16] and gas lifted wells under an appropriate tracer selected with the purpose of small leakage point location [17]. Other approaches such as machine learning and data-driven models have also been used for incident prediction and detection, such as Gaussian Process Regression model [18], and Bayesian approaches [19,20].

However, the main weakness of the mentioned methods is their inability to predict tubing leakage location, especially in the circumstance of the tubing leakage which is considered as the main source of SCP. These conventional tools for SCP detection inevitably interfere with normal operations, and the leak detection, and the location technique without downhole operation is therefore needed for remediation of the gas wells with SCP at lower costs and risks. Incorporating the effects of uncertainties on downhole tubing leakage location seems to be missing in the existing analytical models due to complicated reservoir information and measurement errors. Therefore, this paper presents a newly tool for prediction of the downhole tubing leakage location. A calculation model of tubing and annulus pressure profiles is established on heat transfer theories, mass conservation equation, and multiphase flow theories. Then the position of the tubing leakage in the production tubing is determined by the pressure difference. Tubing leakage location within a certain range is obtained by the calculation of dynamic confidence intervals. In addition, a probability-based model integrating Bayesian inference, and Monte Carlo simulation is developed and applied in an offshore field gas well to predict the likelihood of tubing leakage location.

2. Proposed methodology

2.1. Theoretical model for wellbore pressure distribution

2.1.1. Calculation of wellbore temperature

As the gas pressure in the tubing decreases during the middle and later stages of production, the condensate oil and water, as well as formation water which is precipitated will gradually gather into the well and be carried to the offshore platform by gas [21]. Therefore, the flow in the tubing is considered to be the gas-liquid two-phase flow. Assuming that the heat transfer from high temperature fluid in the tubing to outer edge of wellbore cement sheath is in a steady state, while that from outer edge of wellbore cement sheath to the formation is in an unsteady state [8]. The heat gradient transferred from high temperature fluid to cement sheath surface, that from cement sheath surface to formation, and that from casing to cement sheath surface can be expressed respectively as:

$$\frac{dQ_1}{dz} = \frac{2\pi R_{to} U_0}{G_t}(T_f - T_{cem}) \tag{1}$$

$$\frac{dQ_2}{dz} = \frac{2\pi k_{cem}}{G_t T_D}(T_{cem} - T_h) \tag{2}$$

$$\frac{dQ_3}{dz} = \frac{2\pi k_{cem}}{\ln(R_{ce}/R_{co})}(T_{co} - T_{cem}) \tag{3}$$

where T_f, T_{cem}, and T_h are the temperature of wellbore fluid, cement, and formation respectively, K. G_t is total mass flow rate, kg/s. T_D is the time function of transient heat transfer. k_{cem} is the thermal conductivities of cement sheath. R_{to}, R_{co} and R_{ce} represent outside diameter of tubing, casing and cement sheath respectively. U_0 denotes the overall heat transfer coefficient [22].

Combining Eqs. (1) and (2), based on the energy conservation principle, the fluid temperature distribution in the tubing can be given by [23]:

$$T_{fo} = T_{ho} + \frac{C_{pm} G_t (k_{cem} + R_{to} U_0 T_D)}{2\pi R_{to} U_0 k_{cem}}\left[1 - e^{\Delta z \cdot \left(\frac{C_{pm} G_t (k_{cem} + R_{to} U_0 T_D)}{2\pi R_{to} U_0 k_{cem}}\right)^{-1}}\right]\left(-\frac{g}{C_{pm}} + \phi + g\right) + e^{\Delta z \cdot \left(\frac{C_{pm} G_t (k_{cem} + R_{to} U_0 T_D)}{2\pi R_{to} U_0 k_{cem}}\right)^{-1}} \cdot (T_{fi} - T_{hi}) \tag{4}$$

Combining Eqs. (2) and (3), the casing temperature at a certain depth can be expressed as [8]:

$$T_{co} = T_h + \frac{R_{to} U_0 \ln(R_{cem}/R_{co})(T_f - T_h)}{k_{cem}} \tag{5}$$

2.1.2. Calculation of wellbore pressure

The calculation of wellbore pressure is divided into two parts: Tubing pressure and annulus pressure. According to the conservation law of mechanical energy, the pressure gradient of gas-liquid two-phase flow in the length of tubing is expressed [10]:

$$\frac{dP}{dz} = \rho_m g - \frac{2f\rho_m v_m^2}{d} - \rho_m v_m \frac{dv_m}{dz} \tag{6}$$

where P is the flow pressure, g is the gravitational acceleration, m/s^2, ρ_m is the average density of mixture fluid in the tubing, kg/m^3; f is the friction coefficient; v_m is the velocity of mixture fluid in the tubing, m^3/kg; d is the inner diameter of tubing, m; and z is the well vertical depth (for a directional well with angle of inclination θ, $z = z\cos\theta$.)

The critical parameter of gravity pressure gradient is the average density of the gas-liquid flow in the tubing, which can be expressed as:

$$\rho_m = \left(\frac{1000\gamma_o}{B_o}\right)\left(\frac{1}{1+WOR}\right) + \left(\frac{1000\gamma_w}{B_w}\right)\left(\frac{WOR}{1+WOR}\right)(1-\alpha)\left(\frac{P}{0.101325}\right)\left(\frac{293.15}{T}\right)\left(\frac{1}{Z}\right)\alpha \tag{7}$$

where α is the gas void fraction which is continually changing as the fluid flows from tubing to the ground [21]. γ_o is oil relative density, γ_w is water relative density, WOR is the water-oil ratio, B_o is oil volume factor, B_w is water volume factor, T is tubing temperature, and Z is compressibility coefficient of natural gas.

The mixture velocity can be obtained by:

$$v_m = \frac{Q_l\left(GLR - R_s\frac{1}{1+WOR}\right)}{86400A}\left(\frac{0.101325}{P}\right)\left(\frac{T}{293.15}\right)Z + \frac{Q_l}{86400A}\left(B_o\frac{1}{1+WOR} + B_w\frac{WOR}{1+WOR}\right) \tag{8}$$

where GLR is gas liquid ratio, m^3/m^3. R_s is solubility of gas in oil, m^3/m^3. A is tubing area, m^2.

The tubing pressure at the different well segment with depth Δz will be evaluated as

$$\Delta P = 10^{-6}\left[\Delta z\left(\rho_m g + \frac{fQ_l M_t^2}{9.21\times 10^9 \rho_m d^5}\right) + \rho_m \Delta\left(\frac{v_m^2}{2}\right)\right] \tag{9}$$

where Q_l is total liquid production rate, m^3/d, and M_t total mass of fluid associated with 1 m^3 of liquid, kg/m^3.

Similar to the tubing, the annulus pressure profile in the axis direction can be calculated on the basis of the energy equation. Since the gas in the annulus is relatively static, the friction pressure gradient and acceleration pressure gradient are assumed to zero. The annular pressure distribution can be divided two parts: The pressure in tubing-production casing annulus above liquid level and that below liquid level considering the hydrostatic pressure of the liquid column.