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Review Article

Early gas kick detection in vertical wells via transient multiphase flow modelling: A review

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ABSTRACT

Gas influx from reservoir into the wellbore during drilling, tripping, or other operations, is a hazard. In the early stages, the influx may be nearly undetectable, but the kick can rapidly change from a seemingly steady condition to one of extremely high flow rate. The resulting uncontrolled release of large amounts of gas on the drilling rig can ignite and explode; causing loss of life, loss of asset, and contamination of environment. A kick perturbs the system; analysis of the resulting transient flow could lead to significant improvement in timely detection of a kick. Timely detection is essential to avoid blowouts. Early detection also allows better characterization of potential blowout, allowing improved response and mitigation efforts. Early gas-kick prediction and analysis through dynamic multiphase flow can lead to significant progress in detection and controlling of High Pressure High Temperature (HPHT) drilling of deep wells, which is vital to prevent gas blowout risk. This review paper aims to provide the current state-of-the-art on the early gas-kick simulation models based on transient multiphase flow to determine the bottom hole pressure and gas kick size and to employ appropriate mitigation plans. A comprehensive literature review on early kick detection showed that the transient one-dimensional two-phase models are prominently researched considering some aspects of heat transfer, gas solubility and homogenous flows. The reported transient two-phase (G-L) flow models are found to be limited to 1-D flow with limited range of operating conditions. Future studies towards more sophisticated 2-D and 3-D simulations of transient multiphase (G-L) flow models using computational fluid dynamics (CFD) tools are recommended. 2-D and 3-D flow simulations using advanced turbulence models can potentially enhance the accuracy in the calculations of phase velocity, temperature and pressure patterns within the annuli of wellbore and can advance the early gas-kick detection process.

1. Introduction

1.1. Importance of timely detection of gas influx in deep HPHT wells

Fossil fuels like coal, oil (petrol, diesel, kerosene etc.) and gas (methane, propane, ethylene etc.), have driven world economic development over the past century. They are currently the world primary energy source with more than 85% of world total energy production comes from them. Nowadays, usage of natural gas (CH_4) worldwide is increasing rapidly in industrial, residential and transportation sectors with production of 3325.8 million tons of oil equivalent in 2018 (BP statistics, 2019). In recent years, Gas to Liquid (GTL) technology converts extracted natural gas or other gaseous hydrocarbons (through well drilling) into liquid hydrocarbons, like diesel fuel via catalytic Fischer-Tropsch process (Artz et al., 2018; Wood et al., 2012). In Qatar, the Pearl GTL project, a Shell-Qatar Petroleum partnership, is the world's largest source of GTL products, capable of producing 140,000 barrels of GTL products and 120,000 barrels of natural gas liquids and ethane per day (Brown, 2009; Chedid et al., 2007; http://Shell.comShell.com, 2020).

Well drilling operation to fulfill the increasing demand of natural gas is a very vital element of oil and gas extraction and exploration process

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(Hossain, 2016). Well drilling technology has been transforming to drilling deeper into a high pressure and high temperature (HPHT) reservoir in a secure and reliable mode. This transformation results in increased drilling expenses and comprises the safety of the drilling rig, (Augustine et al., 2006). Thus, any attempts to reducing drilling expenses may impact safe drilling in an untested gas kick condition (Paula et al., 2009; Shadravan and Amani, 2012).

In fossil fuel exploration process, to penetrate a deep HPHT reservoir without any accidents, appropriate well control via monitoring of surface measurement parameters during gas influx is needed to reduce the gas flow to the rig area (Brakel et al., 2015). The absence of efficient kick mitigation plan can trigger accidents like gas blowout (Elmore et al., 2014; Grace, 2017). A gas kick during drilling process as shown in Fig. 1, is described conventionally as an uncontrolled and unintended flow of reservoir gas inside the well (Agbakwuru et al., 2017). Gas influx arises when the drilling fluid hydrostatic pressure, in the bottom of the well, drops below the pressure of the formation. Gas kick in drilling frequently occurs in HPHT gas reservoirs as the pore pressure at the bottom well region is higher than the hydrostatic pressure of drilling fluid. This will initiate gas flow into the well annulus in the form of compressed bubble that may be soluble in the drilling fluid. The influx of low dense gas leads to replacement of high dense drilling fluid (mud) in the wellbore. This low dense gas moves upwards against gravity due to buoyancy through well annuli, which leads to reduction in the hydrostatic pressure head in the well. Furthermore, gas expansion increases as gas moves towards the surface with low pressure and temperature. Also, the degassing rate increases at reduced pressures as depth of well declines. This dissolved and undissolved gas movement with expansion and degassing (low gas dissolution into drilling fluids) continues and accelerates; and the kick can develop and multiply. If such kick is not noticed and controlled, it will lead to blowout, which is extremely expensive financially and environmentally, and most importantly, could cause loss of human life.

In most situations, it is tough to identify gas influx at its initial phase. Onshore and offshore blowouts are primary source of accidents in the drilling rig as observed in the deep water horizon Macondo blowout in April 20th, 2010, (Pinkston and Flemings, 2019). This blowout, lasting 87 days, caused about 172 million gallons of gas-saturated oil leak into the Gulf of Mexico at a depth of 1522 m, (Paris et al., 2018). This reinforced the vital goal to appropriately control the blowout through timely detection of gas influx in the deep HPHT well.

1.2. *Surface monitoring parameters for early gas kick detection (EKD)*

Drilling fluid or mud is employed to remove the rock particles from the well after drilling and to retain the wellbore thermal stability during drilling operations to reduce the temperature of the drill bit. At present, three drilling mixtures are considered widely for wellbore drilling process; namely aqueous Water Based Mud (WBM), non-aqueous Synthetic Based Mud (SBM) and Oil Based Mud (OBM) as displayed in Fig. 2. Compared to aqueous drilling fluids, non-aqueous drilling fluids (OBM and SBM) possess better thermal stability under HPHT deep well drilling situation. Besides, non-aqueous drilling fluids provide an enhanced and efficient drilling due to improved lubricity, reduced frictional heat and enhanced wellbore stability. Therefore, non-aqueous drilling fluids, mainly OBM, are regularly used in HPHT deep well drilling operation.

The main parameters considered to monitor early kick detection (EKD) in deep well drilling are: well head pressure (WHP), pit gain, drilling fluid flow in and out, Pressure-Volume-Temperature (PVT) of the drilling fluid and choke pressure (Carlsen et al., 2013; Rommetveit et al., 1989). These parameters are useful further to decide gas kick scenarios and to evaluate bottom hole pressure (BHP), pore pressure of reservoir and mud kill properties for advanced well control and mitigation (Avelar et al., 2009; Jahanpeyma and Jamshidi, 2018). Gas influx in the well displaces drilling mud from the annulus of the well. This would raise the mud level in the storage tank (pit gain). The measurement of the rise in volume of mud is considered as one of the criteria for

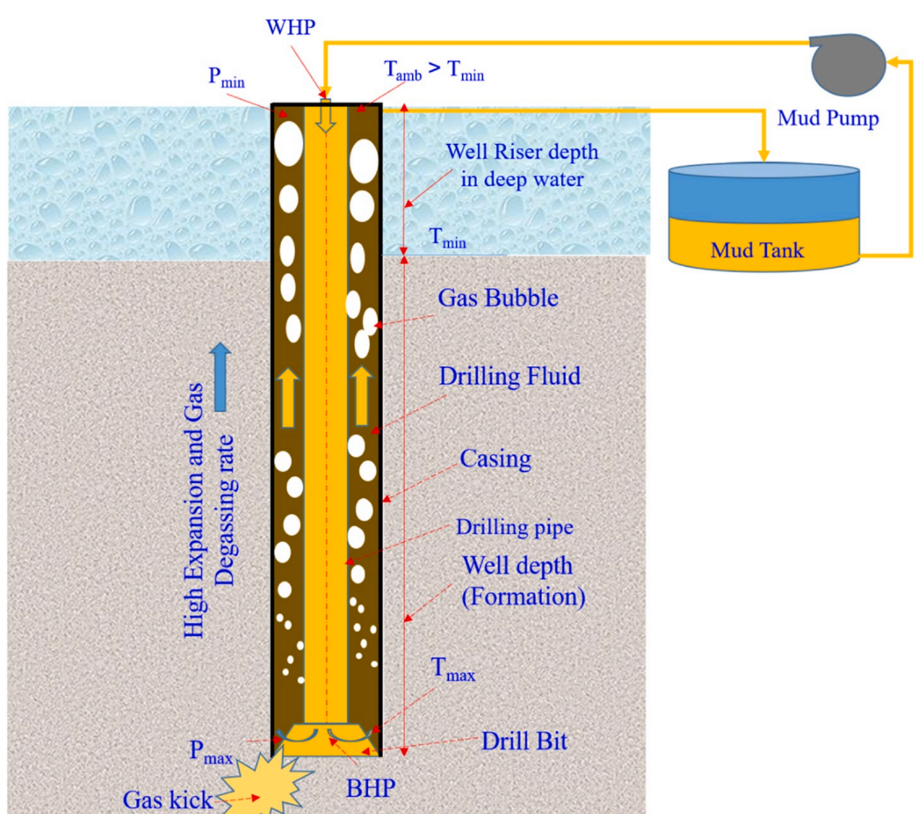

Fig. 1. Overall vertical drilling well with gas kick and multiphase flow.

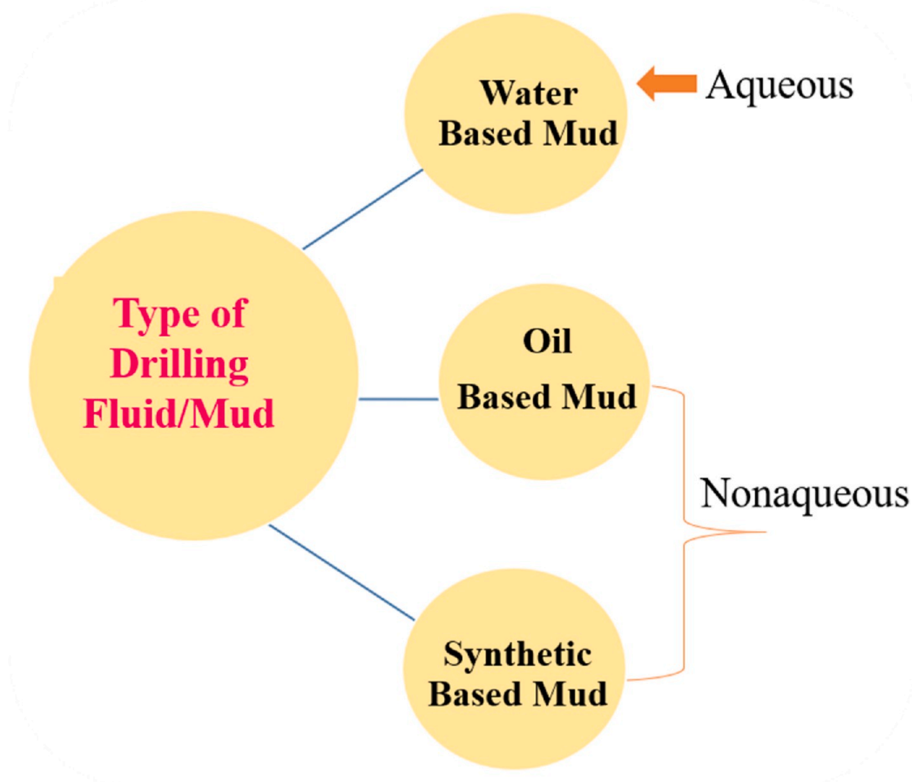

Fig. 2. Type of drilling fluid (mud) used in well drilling process.

detecting a gas kick as shown in Fig. 1.

In deep-water HTHP drilling, it is challenging to identify the incidence of gas influx in terms of pit gain because a large fraction of the entering gas gets dissolved in the mud (with OBM and SBM) at the bottom of well. This makes it difficult to observe enough pit gain to confirm gas kick scenario (Yin et al., 2019) as shown in Fig. 1. In such a case, significant degassing occurs due to lowering of pressure as the gas reaches the riser of the well and starts to expand at higher rate displacing the drilling fluids rapidly in a short period of time. This reduces the chances to employ well control and mitigation procedures and possibly will cause explosion/blowout (Feng et al., 2019).

Timely detection of gas kick is extremely crucial due to the substantial associated risks and many researcher are working on it (Agbakwuru et al., 2017; Amin et al., 2019; Yin et al., 2019). Recently, transient multiphase (two phase G-L) model-based kick detection methods have been investigated for OBM and SBM drilling fluids. The annuli axial pressure profile and BHP measurements have been reported based on the analysis of two-phase flow within the well. These multiphase flow models generally consider three main physical processes namely, heat transfer, gas solubility and hydrodynamics flow to predict temperature, pressure, phase fraction and velocity profile within the annuli. The principal purpose of the present paper is to assess and review these widely used models and empirical correlations described in the open literature and understand their importance for the EKD simulation accuracy.

2. Early kick detection (EKD) simulation

In open literature, various attempts have been made to detect kicks using several technologies including electrical resistance technology, ultrasonic, hydrostatic, video, and using other sensors (Ahmed et al., 2016; Pournazari et al., 2015; Rehman et al., 2019; Toskey, 2015; Zahid et al., 2018). While quick processing of the sensor data is essential to generate gas kick size, flow regime and BHP, however, the use of such sensors is expensive. Transient EKD simulation with consideration of multiphase flow (mainly two-phase gas and liquid) plays very important role in analyzing flow patterns and characteristics in terms of pressure profile, temperature profile, phase fraction and gas compositions along the depth of the well (Fig. 1). It is important to know the transient multiphase flow patterns via gas kick simulation in any type of drilling mixture through HPHT wellbore drilling process, such that the BHP can be precisely forecasted and efficiently used to kill the gas kick at an early stage via appropriate drilling fluid properties and well mitigation plan (Ahmed et al., 2016; Bryant et al., 1991; Deregeh et al., 2013; Islam et al., 2017; Stokka et al., 1993; Tank et al., 2008; Zhou et al., 2010).

An early study of gas-kick detection simulator was reported by Thomas et al. (1984) using isothermal models with saturated gas solubility correlation. Their simulation outcome showed that pit gain is the parameter for the detection of gas kick. Also, this pit gain for oil-based mud is less than water based mud due enhanced gas solubility. O'Bryan (1988) investigated the natural gas solubility on well control and noticed that OBM has 100 time more gas solubility than WBM. Such large gas solubility in OBM raises well control issue with low pit gain after gas kick. Rommetveit et al. (1989) have investigated gas kick via dynamic simulator which considers various factors that affect the gas kick like drilling operating conditions, drilling rate, flowrate, depth, reservoir permeability, formation pressure and drillers control methods in OBM. They assumed linear variation of temperature within the depth of well. They studied two different types of kick namely distributed kick and concentrated kick and found same pit gain in both cases. They identified the important drilling operation parameters and optimum well control guidelines. Computer code for the simulation early gas kick was established by White and Walton (1990) for WBM and OBM. They incorporated well bore hydrodynamics, temperature model, mud rheology, dispersion of gas, gas dissolution and multiphase flow. But multiphase characteristics are not accurately incorporated by these models. Slyke and Huang (1990) utilized interactive PC based CO_2 rich gas kick simulation model for hypothetical circulating well with WBM

Table 1
Literature studies on the Transient-1D-two phase EKD simulation models.

Author/Year	Model Details with Drilling Fluid	Hydrodynamics Flow Model	Gas Influx rate	Friction Factor (f)	Fluid Density	Drilling Fluid Viscosity	Heat Transfer (HT)	Gas Solubility	Numerical Scheme	Validation
Meng et al. (2015)	1-D Transient two-phase flow	Drift Flux Model (General and modified)	–	–	Z for ρ_g, Empirical correlation for ρ_l	Average Mixture viscosity (pure G-L viscosity)	Applied Temperature correlation for Heat transfer	Neglected	Advection upstream splitting model (AUSMV), hybrid scheme for flow models and FV	Lab experiments validation: BHP with error ±10%
Ambrus et al. (2015)	1-D Transient two-phase flow	Reduced Drift Flux Model approach	–	Single and two Phase via Breggs and Brill Correlation	Hall-Yarborough correlation	–	Assumed constant T and geothermal gradient	–	explicit numerical solution algorithm	Experimental and commercial simulator Validated BHP, mud flowrate
Wang et al. (2016)	1-D- Transient G-L for WBM	Flow pattern independent DFM	Flowrate 0.7565 and 0.5265 m^3/s	Garcia correlation	–	Assumed Constant	–	–	Implicit backward time integration scheme, Finite volume (z), staggered grid, First order upwind	Experimental data: BHP (difference 1.39%)
Yin et al. (2017)	1-D Transient two-phase flow, OBM	–	Used empirical correlation in term of reservoir	–	Modified PR, ρ_lT and P: Guan Model	Yan and Zhao Model: Viscosity for T and P	Hasan and Kabir Correlation	Mass transfer velocity model and S_h	Implicit finite difference, Four-point difference scheme	Published Data. (difference 5%)
Xu et al. (2018)	1-D Transient two-phase flow	DFM with Shi correlation	Used empirical correlation	Considered Empirical correlation	Empirical correlation	Empirical Correlation Z	empirical Correlation for h, HT in between annulus mud to formation	Interphase mass assumed zero	Advection upstream splitting model (AUSMV) hybrid scheme for flow models and Finite difference for energy	Experimental and field data Validated: transient T and BHP
Xu et al. (2019)	Transient, 1-D, Two-phase flow (G-L) OBM	Drift Flux Model with Shi Correlation	Used empirical correlation	Empirical correlation	Empirical Correlation for Z	Empirical Correlation in terms of T	Empirical Correlation for convective heat transfer coefficient	Empirical correlation With saturated Gas	Finite difference. Outlet: constant WHP Inlet 1: Flowrate of Drilling Fluid Inlet 2: Gas influx Correlation	Both Field and Experimental data Parameters: Pit gain, BHP with time
Yang et al. (2019a, b)	Transient, 1-D, Two phase flow (G-L) OBM	Drift Flux Model with Shi Correlation	Used empirical correlation	–	–	–	-Joule- Thomson - interphase - conduction - dissolution -HT in drill	Developed interphase mass transfer model	fully implicit finite difference method	Both Field and Experimental data Parameters: Pit gain, BHP
Mao et al. (2019)	Transient, 1-D, Two phase flow (G-L) OBM and for gas (CH_4 $+H_2S$)	DFM with different C_0 and V_d. correlation for bubble, slug, churn	Used empirical correlation	Shear stress in between G-L, Correlation for single and two phase	Ideal gas EOS in terms Z	–		H_2S solubility via PR- EOS and fugacity coefficient	Finite difference method BHP, Pit gain after shut in, total flowrate Initial: WHP, v, liquid fraction	Experimental data of BHP, Pit gain
Manikonda et al. (2019)	Transient 1-D, two Phase flow WBM, OBM	DFM, Taylor bubble flow through annuli	Used constant gas influx	Mud friction loss is reduced to zero.	PR EOS and Van der Walls mixing rule	–	Not studied assumed linear variation of T	Gas solubility correl., Four correlation model of B_0 (for mud)	Semi Analytical Models	No
Chandrasekaran and Suresh Kumar (2019)	Transient 1-D, two Phase flow, OBM	DFM with Shi correl. with $C_0 = 1–1.2$ and $V_d = 0.55$ m/s	concentrated and distributed kick	Wall and gravity friction correlation	Averaged Mixture correlation of $\rho_l$and ρ_g	Mixture calculated using phase fraction	–	–	Finite volume, Staggered discretization, implicit, first-order upwind scheme	Experimental data
Sun et al. (2019a)		Drift Flux Model	–	–		–				

(continued on next page)

Table 1 (*continued*)

Author/Year	Model Details with Drilling Fluid	Hydrodynamics Flow Model	Gas Influx rate	Friction Factor (f)	Fluid Density	Drilling Fluid Viscosity	Heat Transfer (HT)	Gas Solubility	Numerical Scheme	Validation
	1-D Transient two-phase flow, OBM and WBM				Ideal Gas law, ρ_g		Steady state Temperature model by Kabir	Developed new gas solubility correlation	Finite difference, First order upwind Scheme, Staggered Mesh	Experimental data for gas solubility, South china sea
Gomes et al. (2019)	1-D Transient two-phase flow, OBM and WBM	Drift flux model	–	–	–	–	–	–	Explicit AUSMV with slope-limiter technique for numerical diffusion	
Galdino et al. (2019)	1D Transient, one Phase	–	Darcy's law for gas influx through the rock pore	–	Ideal Gas law	Three viscosity	Isothermal	Assumed Insoluble gas	Finite difference	Field data by Petrobras: Pit gain and P transmission
Jiang et al. (2019)	1-D- Transient G-L for WBM,	Zuber and Findlay correlation	Analytical model	Correlation of Perez-Tellez	Based on Z	–	Energy Balance	Assumed to be zero	Generalized likelihood ratio test (GLRT), Unscented Kalman filter (UKF) algorithm	Validated with (Lage et al., 2003)
Patrício et al. (2019)	–	DFM correlation by Evje and Fjelde	Hauge correlation	Empirical Correlation	Empirical Correlation	–	Isothermal flow	No mass transfer between two phases	AUSMV method Flux-vector splitting discretization	Experimental data
Nwaka et al. (2020)	Transient 1-D, two Phase flow	new drift-flux model for narrow annuli		–	EOS and Z-based Hall and Yarborough	–	–	–	Finite Difference, Forward Difference (t), Backward difference (z)	Experimental: Air-H_2O system for gas fraction

and OBM. Their simulation predicts pit gain, annuli flowrate and casing pressure. They concluded that the rise in pit gain and annuli flowrate is not sufficient to detect small kick in OBM due to gas saturation. Unsteady state simulation of EKD with consideration of conservation equations have been used to simulate gas kick in vertical drilling. Numerical simulations of mass and momentum and drift flux model for multiphase flow have been used to predict under-balanced well drilling operation. These simulations, although were validated against full scale experiments, however they ignored the energy models. As shown in Table 1, recently, most of the research applies three governing equations (continuity, momentum and energy balance) to model the transient nature of EKD. These governing equations of 1D transient gas kick simulations are discussed in detail in section 3.

Most kick models available in literature do not accurately account for variation of fluid temperature and phase fraction along the wellbore, much less its change with time as a kick is taking place. The gas temperature changes as it expands while flowing upward the well and due to heat exchange with the surroundings. Because of their influence on gas solubility into the drilling fluids, volume factor, bubble expansion and temperature variation are of great importance, especially for deep HPHT wells. Not only temperature variations are not accurately accounted for in available models, neither are the effects of temperature, pressure, solution gas or liquid gas mixtures on the drilling fluid properties.

2.1. EKD modelling and influencing factors

A sophisticated forecasting methodology to mimic the transient multi-phase flow characteristics coupled with gas intrusion dynamics in annulus of wellbore is highly desirable. Even a simple model of the gas influx dynamics could substantially enhance the timely wellbore mitigation plan. Therefore, simulating early detection of gas kick is critical. The early gas kick detection depends on various parameters as demonstrated in Fig. 3.

As the gas influx in the well begin to rise upward along with drilling fluid through the annulus, it will start to expand with decreasing well depth due to low hydrostatic pressure. It also will continuously displace the drilling fluid out of the annulus into the pit (pit gain). Thus, the drilling fluid flow rate from annulus depends on gas rise velocity as well as on its expansion rate. In turn, the gas expansion rate will depend on both the pressure and the temperature along the well depth. Thus, EKD modelling to solve the coupled fluid flow, heat and momentum transport is required. Along with gas PVT relations, the governing equations of mass, momentum and energy generate the constitutive equations. The mass and momentum balances for a differential depth of the well are given in terms of wellbore fluid density, fluid velocity, cross-sectional flow area, and other important variables. Details of the development of each model available in open literature and its parameters are discussed here separately to determine their importance for kick detection. Also, all mathematical governing conservation equations reported in the open literature (Avelar et al., 2009; Mao et al., 2019; Rommetveit et al., 1989; Sun et al., 2017; Xu et al., 2019) and used to solve (both analytically and numerically) for mass (free gas and drilling fluid), momentum and energy are provided and discussed. Based on the findings, the overall EKD modelling approach to solve for pressure, temperature and phase pattern within deep wellbore has been developed and is shown in Fig. 4.

3. One dimensional modelling approaches

Accurate prediction of phase fraction, fluid velocity profile of both phases, temperature and pressure patterns within the annuli is only possible through appropriate selection of models for each parameter shown in Fig. 4. A list of these 1-D EKD simulation models investigated by several researchers has been compiled and is shown in Table 1. The Table shows that many researchers used models that are transient, one-dimensional, two-phase with combination of various correlations to

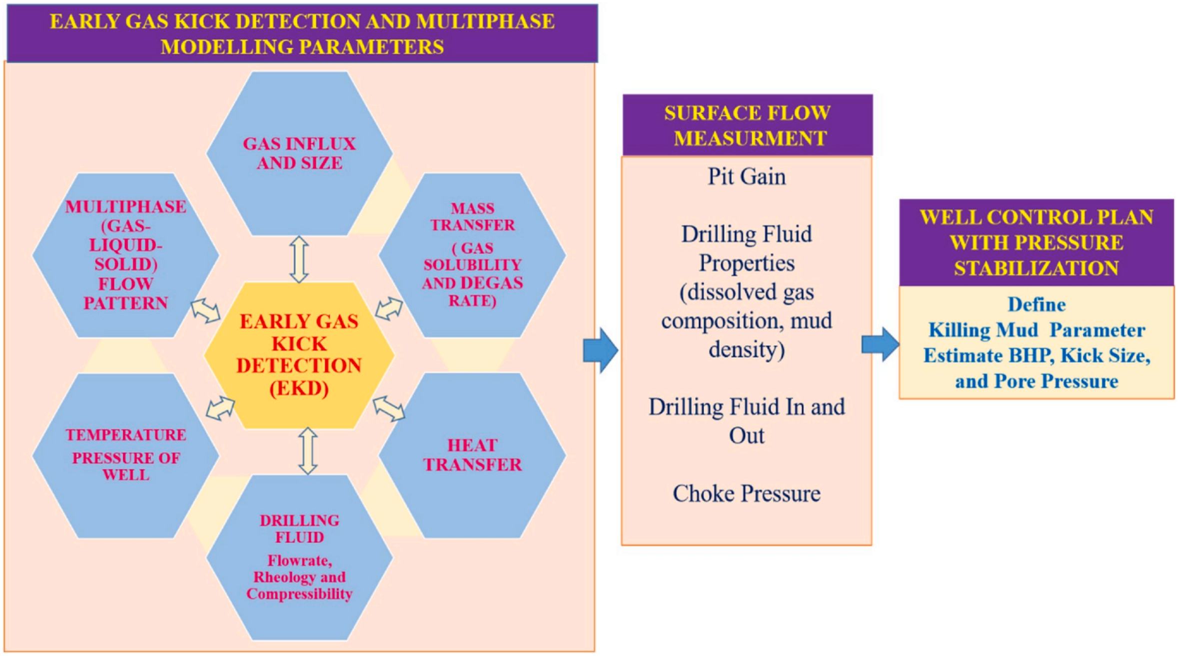

Fig. 3. Early kick detection modelling parameters towards well control.

account for the heat transfer, gas solubility and two phase with different flow regimes. In terms of handling the thermodynamic properties, these models used different equations of state and correlations as shown in Table 1. In terms of the numerical methods used to solve the governing equations and the correlations of these models, different methods were used including implicit, explicit and hybrid schemes as summarized in Table 1.

In the following section, the governing equations for mass, energy and momentum conservation are introduced followed by a review of the modelling approaches and considerations. The EKD simulation deciding factors and their effect on the kick detection are discussed separately for the different models.

3.1. Governing equations

$$\frac{\partial(A\rho_g\alpha_g v_g)}{\partial t}+\frac{\partial(A\rho_l\alpha_l v_l)}{\partial t}+\frac{\partial(A\rho_g\alpha_g {v_g}^2)}{\partial z}+\frac{\partial(A\rho_l\alpha_l {v_l}^2)}{\partial z}+\frac{\partial(AP)}{\partial z}+\left(\rho_g\alpha_g+\rho_l\alpha_l\right)Agsin\theta+\frac{Af}{2d_c}\left(\rho_g\alpha_g {v_g}^2+\rho_l\alpha_l {v_l}^2\right)=0 \tag{4}$$

3.1.1. Mass conservation

The dynamic 1D mass conservations within the wellbore annuli for free gas, drilling fluid and dissolved gas into the drilling fluid are expressed in equations (1)–(3) (Avelar et al., 2009; Meng et al., 2015; Yang et al., 2019a, b). In these equations, ρ_g,ρ_l are the densities, v_g, v_l are the fluid velocities, A is the cross-sectional flow area, $\dot{q}_g$ is the gas influx, x_{g_sol} is the mass fraction of the dissolved gas and $\dot{m}_{g-o}$ is the interphase mass transfer rate from the vapor phase to liquid phase.

For the gas influx (Gas phase):

$$\frac{\partial\left(A\rho_g\alpha_g\right)}{\partial t}+\frac{\partial\left(A\rho_g\alpha_g v_g\right)}{\partial z}=\dot{q}_g-\dot{m}_{g-o} \tag{1}$$

For the drilling fluid (Liquid phase):

$$\frac{\partial(A\rho_l\alpha_l)}{\partial t}+\frac{\partial(A\rho_l\alpha_l v_l)}{\partial z}=\dot{m}_{g-o} \tag{2}$$

For the dissolved gas into the drilling liquid:

$$\frac{\partial\left(A\rho_l\alpha_l x_{g\_sol}\right)}{\partial t}+\frac{\partial\left(A\rho_l\alpha_l v_l\alpha_{g\_sol}\right)}{\partial z}=\dot{m}_{g-o} \tag{3}$$

3.1.2. Momentum conservation

The momentum conservation equation of both gas and liquid phase with consideration of well wall friction (f), pressure (P), slip to account for relative G-L phase velocity and potential energy due to gravity (White and Walton, 1990; Qu et al., 2017; Yang et al., 2019a, b) is expressed as:

where, f is the well wall frictional factor and d_c is the diameter of well annuli.

3.1.3. Energy conservation

Gas kick during well drilling causes gas-liquid multiphase flow, based on gas influx capacity and heat transfer. Both multiphase flow and heat transfer affects the pressure and drilling fluid temperature, which in turn influence the gas solubility and gas expansion. Therefore, it is crucial to assess the heat transfer and temperature patterns along the depth of well during gas kick scenario. The transient net energy gain by the drilling fluid in the annulus after heat transfer from surroundings (both from formation and sea) to annulus drilling fluid and energy loss

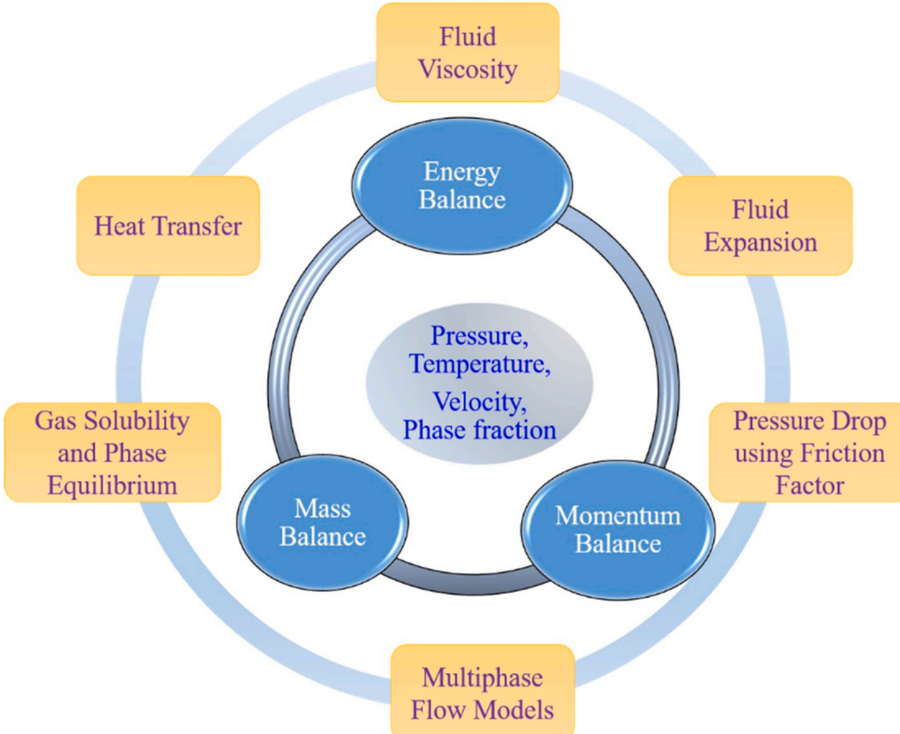

Fig. 4. Overall multiphase modelling approach.

from annulus to drilling fluid (Yin et al., 2017) is given in the overall energy balance, equation (5). The overall energy balance equation is based on the first law of thermodynamics, where the left side term represents the energy accumulation by the drilling fluid mixture within annuli. Then the first and second part of the right-side of equation (5) involves energy flux along the depth (z) due to the flow of gas and drilling fluid and the amount of work done on the fluid by the gravity effect.

$$\frac{\partial\left[\rho_{lm}\alpha_l\left(u_l+0.5{v_l}^2\right)+\rho_g\alpha_g\left(u_g+0.5{v_g}^2\right)\right]}{\partial t}=\frac{\partial\left[\rho_l\alpha_l v_l\left(u_l+0.5{v_l}^2+\frac{P}{\rho_{lm}}\right)+\rho_g\alpha_g v_g\left(u_g+0.5{v_g}^2+P/\rho_g\right)\right]}{\partial z}+\left(\rho_{lm}\alpha_l v_l+\rho_g\alpha_g v_l\right)g\cos\theta+Q_i\Big/A_a \tag{5}$$

In equation (5), ρ_{lm} is the density of the gas dissolved liquid, $u$is the internal energy, A_a is the annulus area and $Q_i$is then net heat exchange between the drilling fluid (within annulus and drilling pipe) and surrounding formation.

3.2. Heat transfer considerations

Steady and transient heat flow in the wellbore under multiphase flow of gas liquid phase have been widely studied under different configurations using both analytical and numerical methods (Hasan and Kabir, 2010, 1994; Izgec et al., 2007; Yang et al., 2019). Recently Xu et al. (2020) have developed a novel analytical model with energy balance to assess the temperature patterns during drilling process via the involved heat exchange between the drilling fluid (in annulus and drill pipe) and surrounding formation as shown in Fig. 5. The previous studies clearly depict two temperature patterns within the deep-water wellbore where drilling fluid gains thermal energy from the surrounding formation and loses some of the heat to surrounding sea water (due to low temperature of sea water). Also, the temperature of formation increases with the depth of wellbore during drilling operation while that of seawater decreases with depth (Sun et al., 2017).

The transient behavior of the drilling fluid temperature within the well with consideration of net heat transfer (heat gain and loss) was applied in different gas kick scenarios (Ambrus et al., 2015; Fallah et al., 2019; Mao et al., 2019; Xu et al., 2019, 2018; Yang et al., 2019; Yin et al., 2017). For simplicity Manikonda et al. (2019) used linear variation of temperature between 10°C to 150°C with well depth of 10000 ft. Xu et al. (2018, 2019) have considered the well-known Dittus-Boelter correlation for convective heat transfer coefficient and mixture conductivity of the drilling fluid. They considered a thermal resistance network consists of series of thermal resistances from formation to drilling fluid like convective resistance in cement and casing, convective resistance within annulus fluid, conduction resistance in drill pipe and convection in the drilling fluid (Fallah et al., 2019; Mao et al., 2019). Mao and Zhang (2018) used a convective heat transfer coefficient in terms of dimensionless Nusselt number for both turbulent and laminar flow. Meng et al. (2015) applied correlation for well temperature in relation to axial direction of well and drilling fluid circulation flowrate.

A Transient (2-D) multiphase simulation by Yang et al. (2015) showed the importance of predicting the drilling fluid temperature distribution during the gas kick detection under shut-in and circulation. The cases with and without heat exchange were studied by Xu et al.

(2019) and the effect on the dynamic variation of pit gain, gas solubility, temperature patterns, gas influx rate and BHP were compared as shown in Fig. 6. They concluded that, without incorporation of the thermal energy exchange between surrounding formation and drilling fluids, the BHP could be overestimated by 11.4%. Thus, geothermal gradient in the formation over depth of well decides the temperature distribution and influences gas solubility into the oil based drilling fluid, which is essential for gas kick detection purposes.

3.3. Gas solubility considerations

Both, onshore and offshore deep well drilling operate under high pressure and high temperature (HPHT) environments. This makes nonaqueous drilling fluid (OBM and SBM) suitable and acceptable due to their enhanced thermal stability, high vapor pressure and better drilling performance than WBM (Nunes et al., 2002). However, high gas solubility issue becomes prominent in nonaqueous oil and synthetic (OBM and SBM) based drilling fluids compared to WBM (Monteiro et al., 2010; Oudeman and Kerem, 2006). High pressure condition in the deep wells allow high gas solubility into nonaqueous mud which makes it very hard to detect the gas influx until the kick is very close to the rig. Adams and Kuhlman (1990), Sun et al. (2019b) indicated that surface measured pit gain in OBM is an inaccurate sign as large amount of gas dissolves into OBM and thus, it is hard to quantify pit gain and respective kick rate and capacity. Due to high gas solubility in OBM, gas kick can extend towards the drilling rig without any alarm (Gomes et al., 2018).

The gas dissolution into OBM is an important factor for transient hydrodynamics (G-L) flow models. Of equal importance is to determine the degassing rate through the gas phase velocity and temperature and pressure in the wellbore. Literature reports two types of models to determine the gas solubility, namely using correlations that are based on experimental data fitting and using Equations of State (EOS) via thermodynamics phase equilibrium. EOS used to determine gas solubility into OBM become complex with the consideration of mixing rule, (Omrani et al., 2019), which is necessary to define for natural gas mixtures (H_2S, CO_2, CH_4) and oil mixture (emulsifier, saline water, low mineral oil C8 to C12). Feng et al., (2019) showed that binary interaction parameter of Peng-Robinson EOS with mixing rule provides good representation of gas solubility for wider temperature and pressure ranges for deep well.

Experimental investigation of gas (methane, natural gas, CO_2) solubility into OBM by O'Bryan et al. (1988); O'Bryan and Bourgoyne (1990), found that the gas solubility in OBM increases with pore pressure and base-oil composition in the drilling fluid and decreases with the rise in temperature, solids percentage, and composition of brine and emulsifier in the drilling fluid. Their study proposed a first correlation (Table 2) to account for the gas solubility in OBM. However, the developed correlation is not appropriate for HPHT deep well with OBM because it is applicable for limited operational temperature and pressure. EOS based models, however can consider wider range of temperature and pressure and ultimately applicable for deep vertical well (more than 10000 m) where both temperature and pressure are high. Further, O'Bryan and Bourgoyne (1990) reported drilling fluid swelling of dissolved methane by using Peng Robinson EOS. Several correlations for gas solubility and swelling of the drilling fluid have been reported in open literature, which are summarized in Table 2. In these gas solubility correlations, only one correlation reported by Manikonda et al. (2019) considers gas solubility at unsaturated (nonequilibrium) condition, however the remaining correlations (like Standing, Petrosky correlation) are based on the saturated conditions. Overall, it can be understood that early gas-kick detection with gas dissolution in nonaqueous mud (OBM and SBM) takes more time and this gas dissolution and degassing effect are not considered by many researchers. Multiphase models with gas dissolution and degassing rate in oil-based drilling fluids is critical for off-shore rig.

A second approach by using phase equilibrium criteria (fugacity of

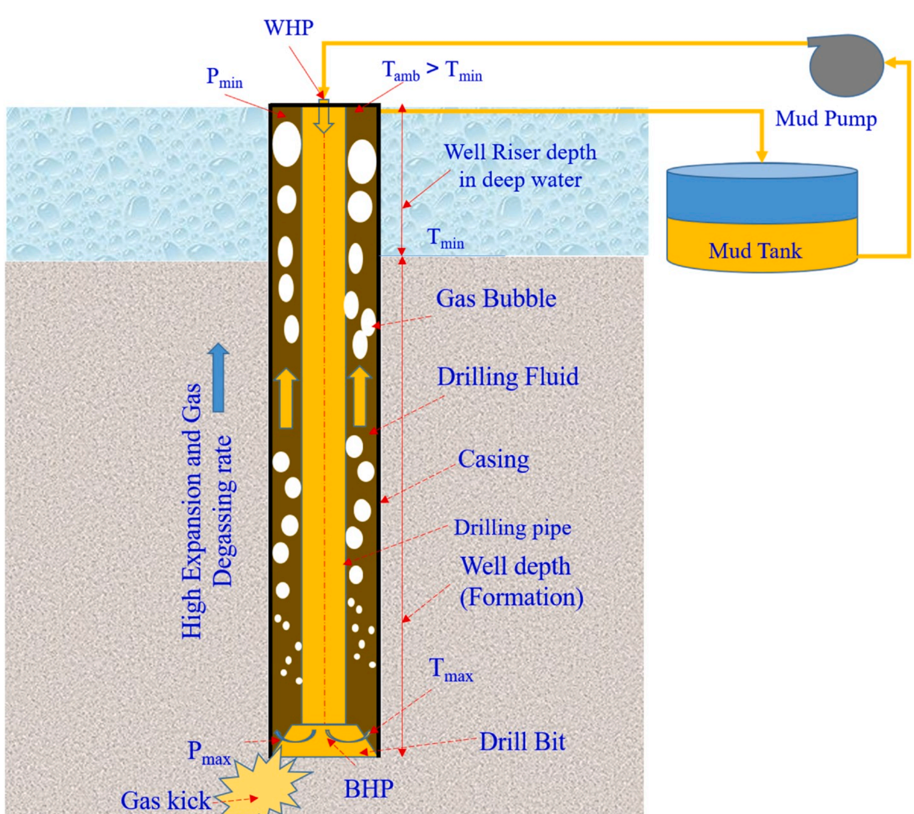

Fig. 5. Heat Transfer during deep well drilling.

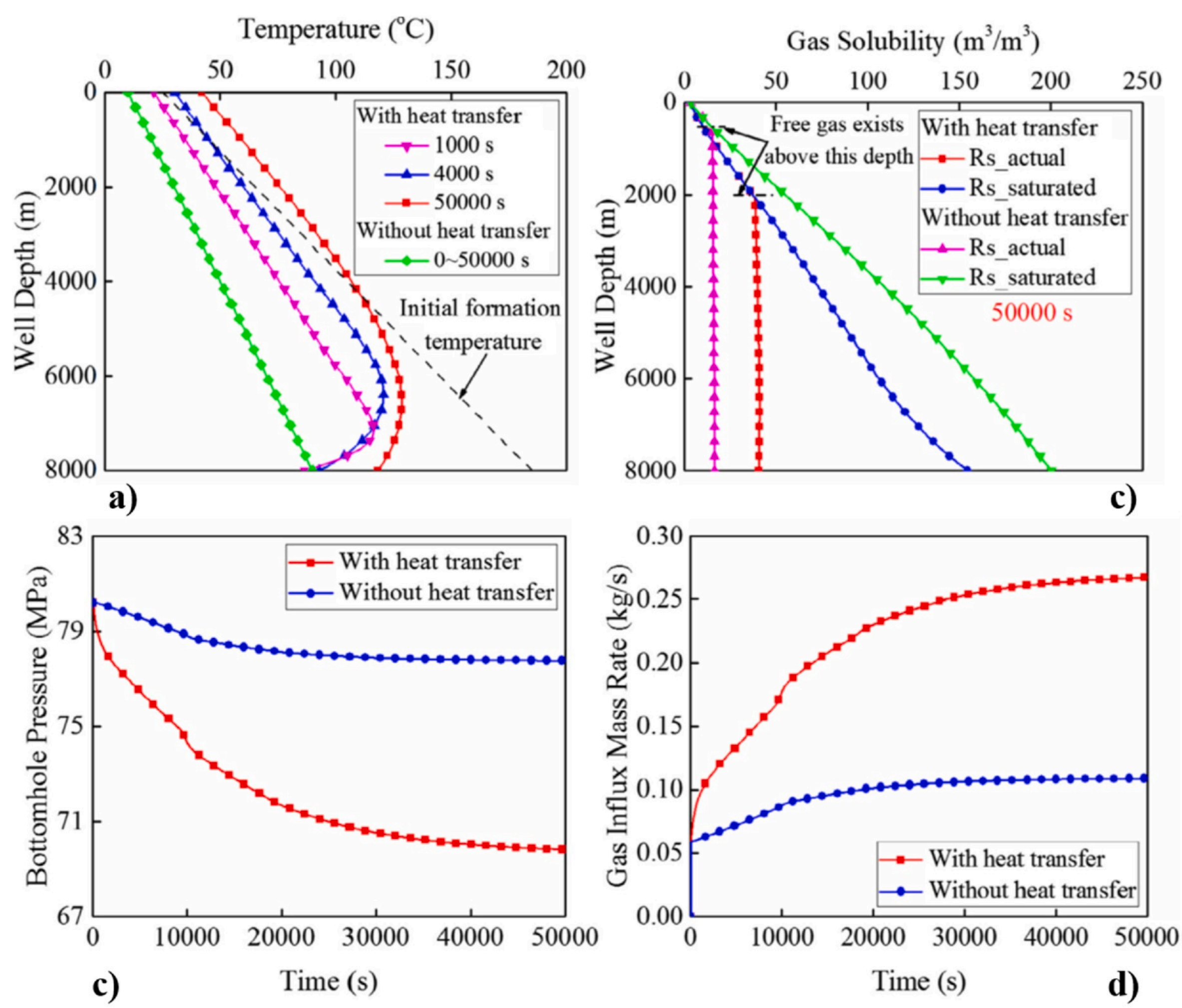

Fig. 6. Effect of flow and heat transfer on Gas kick dynamics (Xu et al., 2019). *a) Temperature b), Gas solubility (Rs), c) BHP and d) Gas influx mass rate.*

each species is the same in G-L phase) with equation of state (EOS) has been considered to determine the dynamic free gas solubility in drilling fluid.

Several authors have used various types of EOS to quantify the equilibrium gas solubility into drilling fluid. Thomas et al. (1984) used Redlich Kowng with mixture rule for binary interaction parameters a_m and b_m as follows,

$$P = \frac{RT}{v_m - b_m} - \frac{a_m T^{-0.5}}{v_m(v_m + b_m)} \tag{6}$$

O'Bryan and Bourgoyne (1990) and Kim et al. (2015) considered PR as EOS to compute the gas dissolved into drilling fluid. The PR EOS for mixture are as follows,

$$P = \frac{RT}{v_m - b_m} - \frac{a_m}{v_m(v_m + b_m) + b_m(v_m - b_m)} \tag{7}$$

Table 2
Correlation based models for gas solubility.

Author	Correlation (Gas solubility, R_s)	Correlation (Volume factor, B_0)
Standing (1947)	$R_s = 0.1781\,\gamma_g\left[\frac{P\times 10^{0.0125API}}{18\times 10^{0.0091(1.8T-459.67)}}\right]^{1.20482}$	$B_0 = 0.972 + 1.47E^{-04}\left[R_s(\gamma_g/\gamma_o)^{\frac{1}{2}} + 1.25(1.8T-459.67)\right]^{1.175}$
Vazquez and Beggs (1977)	–	$B_0 = 1 + 4.677E^{-04}R_s + 1.751E^{-05}(T-60)(\gamma_{API}/\gamma_g) - 1.811E^{-08}R_s(T-60)(\gamma_{API}/\gamma_g)$
O'Bryan et al. (1988); O'Bryan and Bourgoyne (1990)	$R_s = [P/(1.922\,T^{0.2552})]^n$ $n = 0.3576 + 1.168\gamma_g + (0.0027\text{-}0.0049\gamma_g)T$	–
Petrosky and Farshad (1998)	–	$B_0 = 1.0113 + 7.2046E^{-05}(R_s^{0.3738}(\gamma_g^{0.2914}/\gamma_o^{0.6265}) + 0.24626T^{0.5371})^{3.0936}$
Manikonda et al. (2019)	–	$B_0 = B_{0b}e^{[C_0(P_b-p)]}$ $C_0 = \frac{-1433 + 5Rsb + 17.2T - 1180\gamma_g + 12.61\gamma_{API}}{10^5 p}$
Sun et al. (2019a)	$R_s = [P/(11.773T^{0.122})]^{1.29}$	–

where, $a_m$and $b_m$are mixture parameters based on Van Der Waal mixing rule.

Yin et al. (2017) have extended PR in terms of two binary interaction parameters a and b as follows,

$$P=\frac{RT}{v-b}-\frac{\gamma(T)}{v(v+b)+b(v-b)} \tag{8}$$

$$b=\frac{0.0778RT_c}{P_c} \qquad \gamma(T)=\frac{0.45724\alpha(T)R^2T_c{}^2}{P_c{}^2} \tag{9}$$

Manikonda et al. (2019) utilized PR in terms of compressibility factor (Eq (10) and (11)), where A and B are related to interaction parameters a and b as follows,

$$\mathrm{Z^3-(B-1)Z^2+\left(A-3B^2-2B\right)-\left(AB-B^2-B^3\right)=0} \tag{10}$$

$$\mathrm{A=aP/(RT)^2;\ B=bP/RT} \tag{11}$$

Recently Omrani et al. (2019) utilized simple Van Der Waal (Eq. (12)) to calculate gas solubility with a and b as interaction parameters of pure fluids. These a and b depend on the critical properties of the pure fluids.

$$P=\frac{RT}{v-b}-\frac{a}{v^2} \tag{12}$$

Feng et al. (2019) used various types of EOS namely, Soave Redlich Kwong, Peng Robinson with two van Der Waal mixing forms of interaction ($\mathrm{a_m}$) and volume ($\mathrm{b_m}$) parameters as given in Eqs (13)–(15).

$$P=\frac{RT}{v-b}-\frac{a(T)}{v(v+b)} \tag{13}$$

$$P=\frac{RT}{v-b}-\frac{a(T)}{v(v+b)+b(v-b)} \tag{14}$$

$$\mathrm{a_m=\sum_i\sum_j x_ix_j\sqrt{a_ia_j}\left(1-k_{ij}\right);\ b_m=\sum_i\sum_j x_ix_j\sqrt{b_ib_j}\left(1-l_{ij}\right)} \tag{15}$$

where, $\mathrm{k_{ij}}$, $\mathrm{l_{ij}}$ ae two binary interaction parameters of modified PR EOS.

These EOS are tabulated in Table 3 for the convenience of the reader. It can be seen that, PR EOS with Van der Walls mixing rule for mixture have been reported recently for determining free gas solubility into drilling fluid. This allows a better interpretation of the annulus two phase gas liquid flow environment in HPHT well under kick situation (Feng et al., 2019).

3.4. Multiphase flow models

The amount of gas (in free and soluble form) fraction in two phase flow after gas influx within the well annuli is critical aspect for G-L two phase flow modelling since free gas have higher solubility (solubility is directly proportional to pressure and inversely proposition to temperature) in nonaqueous drilling fluid (OBM and SBM) at the bottom of the well. Invaded free gas may become completely soluble to form single liquid phase (see Fig. 7) of nonaqueous drilling fluid and becomes saturated at the bottom of wellbore reliant on gas kick volume and concentration. Phase flow pattern transition in the well annuli from single liquid phase (depending on the gas kick size) to two (gas and liquid) phases can happen as the saturated drilling fluid moves upward with reduction in well depth and the respective hydrostatic pressure. This transition of multiphase flow regime is shown in Fig. 7 from bubble regime to churn regime and then to annular flow regime (Gruber et al., 2014). These types of flow regimes depend on the well depth, pressure, temperature, gas fraction and gas kick size and type. Degassing rate of saturated drilling fluid increases with reduction in the pressure since gas solubility is directly proportional to pressure and inversely to temperature. This results in large amount of free gas release from drilling fluid during the upward flow within annular portion which changes the phase flow regime (Yin et al., 2017). Such phase transition generates more turbulence in the annulus and increases the flowrate due to drift (bubble rise velocity) of gas bubble with reduction in the hydrostatic pressure of well.

For this, better understanding of two-phase G-L flow pattern (phase fraction and phase velocity) plays an important key role in the annulus after gas kick scenario. G-L phase distribution within HPHT deep well is very complicated with consideration of gas solubility and degassing under varying temperature and pressure conditions (Yin et al., 2017). Understanding the two-phase G-L flow regime based on gas kick size and drilling fluid flowrate within annuli is essential to well control and to estimate the kick size and BHP. Distinct G-L two-phase flow regime can reveal the effects of comparative phase fraction, velocity and relative location of each phase in the flow. For this, two phase flow models need to be customized for unexpected gas influx applications.

There is a variety of multiphase flow models that predict velocity, G-L phase fraction and flow rate of each phase within the annulus. Fig. 8 shows the three different types of flow models – namely empirical correlation-based flow models, homogeneous flow models and more detailed mechanistic flow models (Shi et al., 2005). The accuracy of these models increases from empirical to mechanistic type flow models because mechanistic models reflect the physics for each flow pattern.

Most of the previously reported studies in literature consider homogenous type flow models namely, drift flux model (DFM) due to simplicity of calculation of phase velocity and gas fraction (Zuber and Findlay, 1965). DFM assumes that a multiphase mixture performs like one phase to represent the multiphase flow behavior. DFM is simple flow model, applicable for mixture and considers two phase gas liquid properties into single-phase flow models, which allows for consideration of the slip between the gas and liquid phases. DFM has been widely used

Table 3
Equation of State (EOS) based models for gas solubility.

Correlation Reference/year	EOS for gas solubility (R_s)	
Thomas et al. (1984)	Redlich Kowng	$P=\frac{RT}{v_m-b_m}-\frac{a_mT^{-0.5}}{v_m(v_m+b_m)}$ Used mixing rule for parameters a and b
O'Bryan and Bourgoyne (1990) Kim et al. (2015)	PR for mixture	$P=\frac{RT}{v_m-b_m}-\frac{a_m}{v_m(v_m+b_m)+b_m(v_m-b_m)}$ $a_m$and $b_m$mixture parameters via Van Der Waal mixing rule
Yin et al. (2017)	Modified Peng Robinson	$P=\frac{RT}{v-b}-\frac{\gamma(T)}{v(v+b)+b(v-b)}$ $b=\frac{0.0778RT_c}{P_c}$ $\gamma(T)=\frac{0.45724\alpha(T)R^2T_c{}^2}{P_c{}^2}$
Manikonda et al. (2019)	PR in terms of compressibility factor	$Z^3-(B-1)Z^2+(A-3B^2-2B)-(AB-B^2-B^3)=0$, $A=aP/(RT)^2; B=bP/RT$,
Feng et al. (2019)	Soave Redlich Kwong	$P=\frac{RT}{v-b}-\frac{a(T)}{v(v+b)}$
Omrani et al. (2019)	Van Der Waal	$P=\frac{RT}{v-b}-\frac{a}{v^2}$ a and b pure component parameters
Feng et al. (2019)	Peng Robinson with two Van Der Waal mixing rules	$P=\frac{RT}{v-b}-\frac{a(T)}{v(v+b)+b(v-b)}$ Interaction Parameter: $a_m=\sum_i\sum_j x_ix_j\sqrt{a_ia_j}(1-k_{ij})$; Volume Parameter: $b_m=\sum_i\sum_j x_ix_j\sqrt{b_ib_j}(1-l_{ij})$, k_{ij}, l_{ij}= Binary interaction parameters

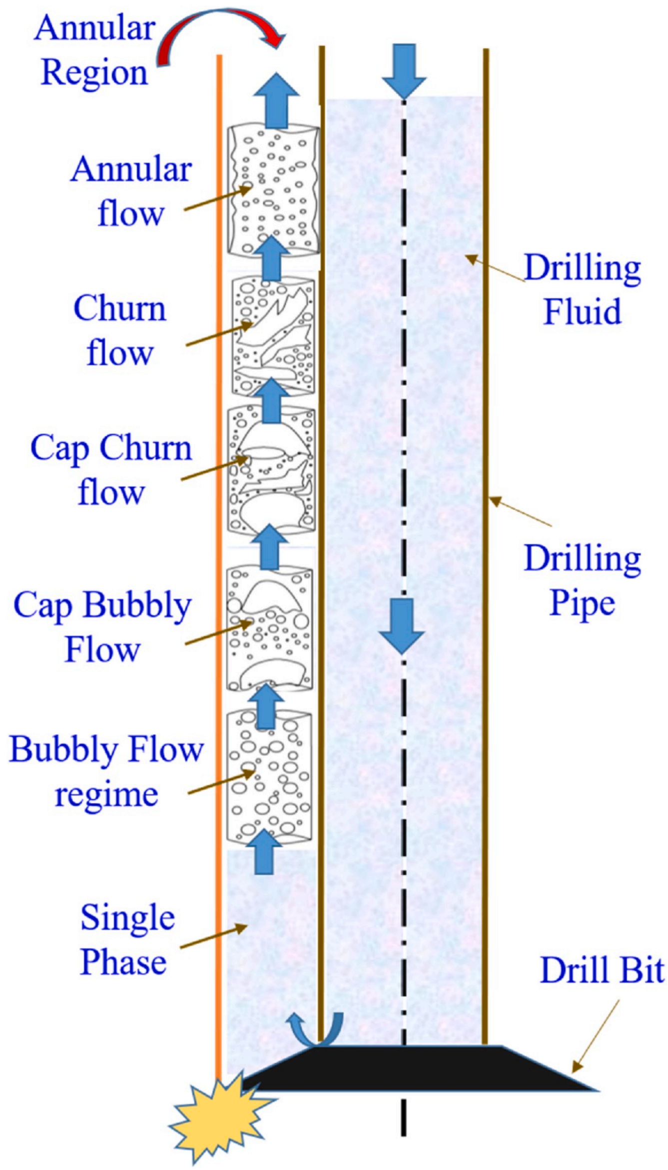

Fig. 7. Variation of flow regime for G-L two phase in the vertical wellbore during Gas kick scenario (Sun, 2016; Wu et al., 2017; Yin et al., 2014).

for bubble or slug type flow pattern and acceptable for well drilling simulator (Aarsnes et al., 2016; Meng et al., 2015). However DFM is inaccurate when applied for other flow regimes such as stratified flow, wavy flow and annular flow (Sun, 2016). Each regime has specific multiphase flow model as shown in Table 4. Bhagwat and Ghajar (2014) have modified DFM model making it independent of flow pattern with two distinct models for drift velocity and distribution parameter for wide range of conditions. Till now, no single flow model has become known to measure pressure drop under the extensive range of circumstances of annulus in the wellbore. The two-fluid flow model (like DFM) involves complicated numerical solution techniques for partial differential equations Ambrus et al. (2015). Such numerical methods are too time consuming and cumbersome. Consequently, efforts to simplify multiphase flow models have been made by several researchers to reproduce and estimate the gas kick scenario before well control and shut-in.

4. CFD studies for EKD simulation

Most of the described mathematical models of heat transfer, gas solubility and multiphase flow used for EKD simulation are 1-D empirical correlations with several simplified assumptions, which are valid for limited range and cases. For accurate and detailed results, Spoerker et al. (2012) recommended considering two- or three-dimensional simulation analysis of EKD within annulus. Nowadays, advanced numerical technique using Computational Fluid Dynamics (CFD) are being used for multiphase systems to solve 3-D governing equation (Li et al., 2013; Sutkar et al., 2016).

Analysis of bubble formation in air water (G-L phase) mixture flowing in upwards pipe using CFD was performed by Lote et al. (2018). They considered the interfacial forces; drag, lift, wall lubrication and turbulent dispersion for the CFD simulation. Sun et al. (2019c) have reported the formation of gas bubble during gas kick with consideration of gas flowrate, density and viscosity and bubble movement and its effect on the variation of temperature and pressure using CFD. They reported the effect of bubble formation and bubble migration on the variation of temperature and pressure and concluded that the accumulation of gas bubble was observed at the bottom of well after gas kick. Guo et al. (2017) used CFD to simulate air-water (G-L flow in wide and narrow annuli) with Volume Of Fluid (VOF) model and $\kappa-\varepsilon$turbulence model. They validated their results for air fraction of air-water system for various superficial velocities. Sultan et al. (2019a, 2019b) investigated the flow characteristics of horizontal well via CFD simulation of multiphase (gas-liquid-solid) phase with 3-D flow in both horizontal and vertical annuli pipe. They predicted pressure loss for different cross-sectional area of pipeline and annuli, which were in good agreement with experimental data (Sultan et al., 2019c).

The literature search depicts that none of the previous studies report CFD simulations for the transient flow after gas influx within vertical HPHT deep well. CFD models need to be established based on the Navier-Stokes equations (Sleiti et al., 2017) to understand the hydrodynamics of annular region based on inlet and outlet boundary conditions. Use of CFD tool for EKD purpose is essential to enhance the accuracy of transient 3-D multiphase flow and further to support timely detection of gas kick via detailed flow patterns and their transition over the axial direction of well. Future work needs to focus on developing gas-liquid two phase CFD model with consideration of all critical multiphase flow parameters, fluid properties, annular pipe geometry, appropriate turbulence model, etc. The use of proper turbulence model (like $\kappa-\varepsilon$) (Sleiti and Kapat, 2006) to overcome the limitation of the current 1-D models is required for the timely detection of gas kick (Gruber et al., 2014; Guo et al., 2017; Sleiti and Kapat, 2006).

5. Summary and recommendations

A comprehensive literature review of early gas kick detection models and simulation studies has been conducted, based on which, a summary of the findings and recommendations are provided as follows:

- Most of the available models were developed for one-dimensional two-phase systems in combination with three physical processes namely
  1. heat exchange from the surrounding formation,
  2. gas solubility and
  3. hydrodynamic G-L flow model.
- The accuracy of the three physical processes are found to be widely explored for EKD and most of them are using empirical correlations.
- The reported empirical models are based on simplified assumptions with reduced complexity like only bubbly flow, one dimensional, simplified effects of gas solubility and mass transfer and linear temperature within well. This leads to inaccuracies in predicting EKD in HTHP wells.
- Most of the studies completely overlooked the beginning dynamics of gas influx interaction with drilling fluid (with and without circulation) at the bottom of the well. Such limitations necessitate the development of two-phase transient models based on actual

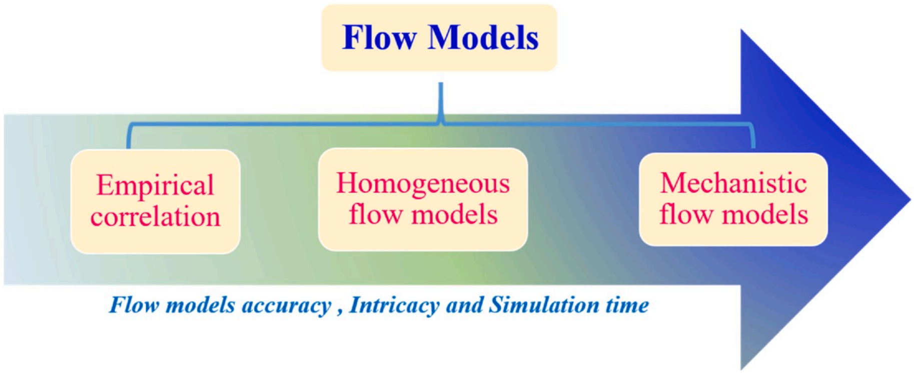

Fig. 8. Types of flow models.

Table 4
Drift flux models (DFMs) used for vertical well after gas kick.

Correlation Reference	Superficial Gas Velocity, v_g	Distribution parameter (C_0)	Slip/Drift Velocity (v_d) m/s	Regime
Ma et al. (2018); Shi et al. (2005); Xu et al. (2019) Meng et al. (2015)	$v_g = C_0(\alpha_l v_l + \alpha_g v_g) + v_d$	$C_0 = \frac{A}{1+(A-1)\gamma^2}$ $\gamma = \frac{\beta - B}{1-B}$	$v_d = \frac{(1-\alpha_g C_0)C_0 K \alpha_g v_c}{\alpha_g C_0 \sqrt{\frac{\rho_g}{\rho_l}} + 1 - \alpha_g C_0}(\cos\theta)(1+\sin\theta)$	Bubble and Slug regime
Kabir and Hasan (1990)	$v_{sg} = \alpha_g(C_0 v_m + v_d)$	$C_0 = 1.2$	$v_d = 1.5[g\sigma(\rho_l - \rho_g)/\rho_l^2]^{1/4}$	Bubbly low
Hasan and Shah (2018); Kabir and Hasan (1990)	$v_{sg} = \alpha_g(C_0 v_m + v_d)$	1.2 for slug flow 1.15 for churn flow	$v_d = \left[0.35 + 0.22\frac{D_t}{D_c}\right]\left[\sqrt{g(D_c - D_t)\frac{\rho_l-\rho_g}{\rho_l}}\right](1+\cos\theta)^{1.2}\sqrt{\sin\theta}$	Slug and Churn Flow
Sun et al. (2019a)	$v_g = \alpha_g(C_0(\alpha_l v_l + \alpha_g v_g) + v_d)$	$C_0 = \frac{2}{1+(0.001Re)^2} + \frac{1.2-0.2\alpha_g^2}{1+(1000/Re)^2}$	$v_d = 1.53(g\sigma(\rho_l-\rho_g)/\rho_l^2)^{1/4} + 0.35(\alpha_g \alpha_l^{1/4})$ $\sqrt{gD(\rho_l-\rho_g)/\rho_l^2}$	Slug and annular flow
Manikonda et al. (2019); Hasan and Shah (2018)	$v_g = \alpha_g(C_0(\alpha_l v_l + \alpha_g v_g) + v_d)$	$C_0 = 1.2$	$v_d = (0.35 + 0.1 d_i/d_0)\sqrt{g d_0(\rho_l-\rho_g)/\rho_l}$	Taylor Bubble, Dispersed bubbly and Slug flows
Guo et al. (2017)	$v_g = (C_0 v_m + v_d)$	$C_0 = \frac{2}{1+(0.001Re)^2} + \frac{1.2-0.2\left(\sqrt{\frac{\rho_g}{\rho_l}}\right)(1-\exp(-18\alpha))}{1+\left(\frac{1000}{Re}\right)^2}$	Wide Annulus $v_d = 1.56[g\sigma(\rho_l-\rho_g)/\rho_l^2]^{1/4}$ narrow Annulus $v_d = 2.335[g\sigma(\rho_l-\rho_g)/\rho_l^2]^{1/4}$	Bubble, Churn

mechanistic flow in 2-D and 3-D flows within well annuli to determine the drilling liquid velocities (axial, radial), pressure and temperature patterns as the gas bubble rises in upwards direction against gravity.

- Accurate fluid thermodynamics properties with temperature and pressure dependence are key to estimating the dynamics of the gas kick scenario in the well.
- The dynamic models would need to develop the initial pressure, temperature and phase profiles just after the gas kick enters into the annulus of the well with considerations of the effect of fluid flow, heat transfer and gas solubility together for the annulus drilling fluid as the gas rises.
- These models should allow calculating the transient nature of rate of mud expulsion from the annulus as a function of pit gain and early kicking confirmation.
- Numerical analysis of 2-D and 3-D two phase modelling of gas kick dynamics using appropriate turbulence models is vital via CFD.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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Nomenclature

Variables

A	Cross sectional area of annulus [m^2]
a_m	Constant for mixture

b_m	Constant for mixture
B_0	Volume factor
C_0	Distribution parameter
d	diameter [m]
f	fraction factor
g	Earth gravity [9.81 m/s^2]
H	Enthalpy [kJ/kg]
$\dot{m}_{g-o}$	mass transfer rate [kg/(ms)]
P	Well pressure [Pa]
P_c	Critical Pressure [Pa]
P_b	Bottom hole pressure [Pa]
$\dot{q}$	gas influx rate [kg/(m s)]
Q_i	Net heat transfer between surrounding formation and mud
R_s	Gas Solubility
R	Gas Constant [J/(mol K)]
T	Temperature [$^\circ C$]
T_c	Critical Temperature [$^\circ C$]
t	time [s]
u	Internal energy [kJ/kg]
v	velocity [m/s]
v_d	drift velocity [m/s]
v_m	Volume of mixture [m^3/kmol]
x	gas solubility into drilling fluid
z	axial distance in well [m]
Z	Compressibility factor

Greek Letter

Υ_g	Specific gravity of gas
α_g	Gas phase fraction
ρ_g	Gas Density [kg/m^3]
ρ_{lm}	Dissolved drilling fluid density [kg/m^3]
ρ_l	Drilling fluids density [kg/m^3]
θ	Well inclination angle [rad]

Subscripts

c	Critical condition
d	drift
g	gas phase
l	liquid phase
max	Maximum
min	Minimum

Abbreviations

BHP	Bottom Head Pressure
CFD	Computational Fluid Dynamics
DFM	Drift Flux Model
EKD	Early gas kick detection
EOS	Equation of State
GTL	Gas to Liquid
G-L	Gas-Liquid Phase
HPHT	High pressure and High temperature
PR	Peng-Robinson
OBM	Oil based Mud
PVT	Pressure-Volume-Temperature
SBM	Synthetic based mud
WHP	Well head Pressure
WBM	Water Based Mud
1-D/2-D/3-D	one dimensional/two dimensional/three dimensional

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