Chapter

Advances in Well Control: Early Kick Detection and Automated Control Systems

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Abstract

The devastating impact of the Macondo blowout incident has underscored the need for effective well barriers, early kick detection systems, and increased automation of well-control operations toward successful drilling and completion operations particularly in deep offshore environments. Early kick detection systems should be capable of detecting a gas influx both during drilling and tripping operations regardless of the drilling fluid system with minimal false-negative alarms, while automated control systems regain well-control eliminating delays or omissions due to human error. In this chapter, developments in the deployment of early kick detection and automated control systems in conventional and managed pressure drilling operations are reviewed. We discuss the use and placement of surface sensors such as the Coriolis flowmeter, smart flowback fingerprinting when the rig pumps are off, real-time gas monitoring along the marine riser and downhole measurements complimented with machine learning algorithms for early kick detection. We then focus on the application of automated well-control systems for managed pressure drilling operations for which gas kicks are circulated without stopping the pumps or shutting in the well and in conventional well operations requiring intelligent tool joint space-out prior to well shut in especially for deep offshore operations.

Keywords: early kick detection, automated well control, gas influx, well barriers, managed pressure drilling, Coriolis flowmeter

1. Introduction

Drilling into deep lying subsurface formations, both onshore and offshore, is required to produce petroleum which is critical to meeting the world's energy mix. A rightly sized drilling rig suited to the operating environment with trained crew, provided by a drilling contractor, is deployed with other service contractors providing services such as drilling fluid engineering and mud logging to drill and complete the well according to the approved well plan. A multidimensional effort termed "Well control" is employed during drilling and completion operations to ensure that formation fluids are brought safely to the surface and subsequently processed to useful forms of fuel and petrochemical feedstock.

The drilling rig is equipped with a well control system which is basically consist of the Blowout Preventer (BOP) stack, the choke manifold, accumulator unit, and a diverter assembly. The BOP stack may be a surface BOP stack as is the case on all land, jack-up and platform drilling operations or a subsea BOP stack which is used for all floating drilling rigs. The BOP is used to seal the wellbore to contain a *kick* thereby shutting-in the well. A *kick* is the unintended flow of fluids from the formation into the wellbore due to the lowering of the hydrostatic pressure provided by the drilling fluid below the formation pore pressure. A typical BOP stack consists of an annular preventer on top, followed three ram-type preventers including a full-bore drilling spool to enable connection of the kill and choke lines. A typical surface BOP stack is shown in **Figure 1(a)**. The subsea stack includes additional control valves and lines to foster remote operation of the BOP within acceptable reaction times as illustrated in **Figure 1(b)**. The hydraulic power required for operating the well control equipment (preventers, automatic valves, and chokes) is provided by the accumulator unit according to its working pressure rating. The choke manifold which generally consists of a manual choke and a remote-controlled choke is used to control the backpressure on the well while circulating out a kick. The choke manifold also provides the least restricted flow possible in case the well cannot be controlled, and the formation fluids need to be flared at a safe distance from other equipment. A diverter assembly is used to divert a gas kick encountered at shallow depth in a safe direction when only a conductor casing is installed as the surrounding formation tends to be too weak to contain a shut-in kick. Generally, an annular-type preventer is installed on top of the conductor pipe beneath which a diverter line of large enough diameter to sustain unrestricted flow is run to a pit [1, 3, 4]. The position of a diverter system is shown in **Figure 1(b)**.

Loss of well control is widely recognized as a major hazard in the oil and gas industry with far-reaching consequences including loss of drilling personnel, negative environmental impact, loss of investments and damage to the companies' reputation [4]. The loss of well control is always initiated by a kick. The failure in detecting

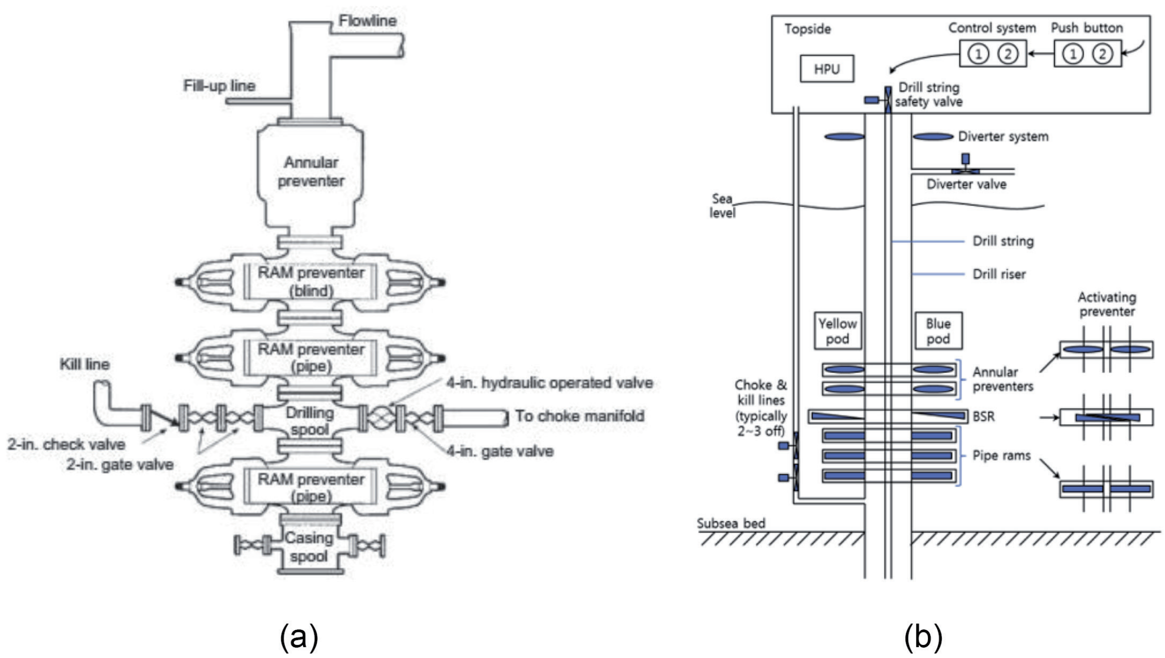

Figure 1.
Left picture (a): a typical surface BOP stack arrangement [1]. Right picture (b): a schematic subsea BOP configuration [2].

a kick or a malfunction in the well control system could result in an uncontrolled flow of formation fluids into the wellbore. This unwanted and uncontrolled flow of fluids is called a blowout [1, 4]. The Loss of well control (LOWC) is thus defined as uncontrolled flow of formation fluids such as gas, oil, water into a separate formation (underground blowout) or exposed at the surface (surface blowout). In addition to equipment failure, a blowout can also result from violation of procedures or human error. The loss of well control is not restricted to the drilling and completion phase as it can occur during work-over activities, and less frequently during production and in abandoned wells [5].

In this chapter we give an overview of essential principles pertinent to maintaining well control such as the role of well barriers and barrier activation in the event of a well control incident. We then discuss conventional kick detection methods, their limitations and early kick detection systems especially for deep offshore operations. We further discuss the adoption of early kick detection and automated well control in managed pressure drilling operations. Finally, automated well control for conventional drilling operations is presented especially the application of artificial intelligence in greatly minimizing human error and thereby increasing the safety of drilling and completion operations regardless of the working environment.

2. Well barriers for maintaining and regaining well control

A well barrier, an item that prevents the fluid flow from the well to the surrounding, is essential to maintaining well control. The two-barrier principle is widely adopted by different regulatory authorities across different petroleum provinces. These two barriers, which are required to be independent of each other, are usually categorized as *primary* and *secondary* barriers with the primary barrier being the closest to the reservoir—the potential source of formation fluids. During the drilling phase, the hydrostatic pressure exerted by drilling fluid is the primary barrier. Thus, the use of the term *primary well control* which refers to prevention of formation fluids into the wellbore by a static drilling-fluid column. The active secondary barrier while drilling is the BOP while the wellhead seals, casing, and cement serve as passive secondary barriers. One exception to the two-barrier rule applies while drilling the top-hole i.e., the first hole section drilled prior to the installation of the Surface BOP on the wellhead. If primary control is lost while drilling the top-hole, the formation fluids from the well are rerouted away from the drilling rig via a diverter [1, 5]. For completion or work-over operations, the designation of a barrier as either primary or secondary is dependent on activities executed during this phase. While the barriers are similar to the drilling barriers for certain aspects of the operation, towards the end of operations sequence, the barriers will be mechanical only, similar to the ones which exist in the production phase. For example, operations carried out through tubing with the well underbalanced with respect to reservoir pressure no longer have the wellbore fluid as a barrier. In a production or injection wells, where packers exist, they will typically become the primary barriers, as they seal off the annulus, the tubing below the surface-controlled subsurface safety valve (SCSSV), and the SCSSV. On the other hand, the secondary barrier envelope would be made up of the tubing above the SCSSV, the X-mas tree main flow side, the casing/wellhead, and the annulus side of the X-mas tree. While the loss of well control can occur anytime during drilling operations, the risk associated with loss of well control is assessed during the well planning phase which precedes well construction [5, 6].

A well control incident occurs when there is a failure either of the barrier(s) or in activating the barrier(s) resulting in an unintentional flow of formation fluid into the wellbore, another formation or to the external environment [7, 8]. The unintended flow of fluids from the formation into the wellbore (a kick) can occur due to several reasons such as insufficient drilling fluid weight (density), not properly filling the drilled hole either while tripping in or out of the well (adding pipe to the drill string to lower it further into the wellbore or removing pipe from the drill string to bring it closer to the surface), swabbing (a decrease in bottomhole pressure due pulling the drill string too quickly), cutting of the drilling fluid by the formation fluids (reduction of drilling fluid weight due to dilution with gas) and lost circulation.

When drilling conventionally, following a kick, loss of well control is prevented by activating the BOP, which in this case is secondary barrier. Failure to close the BOP timely following loss of primary well control would result in increasing influx volume and flow in the annulus of the well. The risk of inability to close the BOP grows with increase in the flow rate. Therefore, successful activation of the BOP is increased by early kick detection. Where there is a substantial kick size, there exist a high chance of subsurface leaks occurring, this can be mitigated by a fast shut-in. [1, 4]. Following closure of the BOP valves, the well is circulated with a higher density drilling fluid using one of the three constant bottomhole pressure (BHP) methods namely wait-and-weight method, driller's method, and the concurrent method. If properly applied, constant pressure at the hole bottom is achieved and prevent additional influx into the well [1, 5].

3. Conventional kick detection

3.1 Kick indicators

There are certain indicators that of primary importance to kick detection. Two of these indicators provide positive signs of influx into the wellbore during drilling while third indicator is relevant to recognizing a kick during tripping operations. To recognize a kick while drilling, two major changes in the rig fluid circulating system (while the rig pumps are on) need to be detected. The first primary indicator is a flow rate increase while pumping at a constant rate as this signifies that the formation is aiding the rig pumps move fluid up the annulus via an influx into the wellbore. The second sign of primary importance while drilling is an increase in pit (mud tank) volume not attributable to surface interventions such as building addition drilling fluid volumes. Fluids entering the wellbore will displace an equal volume of drilling fluid in the flowline and cause an increase in pit level (referred to as *pit gain*). This change in pit level could take some time due to the tank surface area. Surface losses of circulated mud in the return line, shale shakers and transfer tanks supplementing the main mud tanks would have to be accounted for so that the pit gain can be reliable. While tripping the drill string, the kick indicator of primary importance is flow from the well when the rig pumps are off. One notable exception to this (returns from the well with the rig pumps off being a kick indicator) is when a slug is pumped downhole resulting in heavier mud in the drill string than in the annulus [1, 4].

In addition to these primary kick indicators there are warning signs while drilling which if promptly responded to will keep the well under control and prevent the occurrence of a well control incident. These warning signs (secondary indicators) include abrupt increase in the rate of penetration while drilling called a drilling break, increase in torque and drag, changes in mud properties, increase in the shape and size of cuttings, decrease in shale density, increase in gas readings during tripping, connection, circulation or drilling, increase in the temperature of the drilling fluids returns and decrease in the calculated d-exponent. As these secondary indicators are not consistent in all situations they need to be considered collectively. They nonetheless give indication to the potential for an underbalanced situation [1, 4].

3.2 Auxiliary drilling rig equipment for kick detection

The American Petroleum Institute (API 53) standard for auxiliary equipment complimentary to both surface and subsea BOP installations, related to monitoring primary and secondary kick indicators, stipulates that the drilling rig has a trip tank, pit volume measuring and recording devices and a flow rate sensor [9]. The flow rate sensor on conventional drilling rigs is typically the flow paddle type for which the frequency (and voltage signal) generated is proportional to the flow rate. While the flow paddle meter is a low cost, low maintenance solution, it is not suitable for solid-laden fluids and gas flow [10]. It is recommended that the flow rate sensor is mounted in the flow line for early detection of formation fluid entering the wellbore or a loss of returns. The trip tank, a low-volume calibrated tank, that can be isolated from other surface drilling fluid system equipment should be capable of accurately measuring the amount of fluid entering and returning from the well with readout of half a barrel (0.0795 m^3) volume change. The trip tank is primarily used to measure the amount of drilling fluid required to fill the wellbore while tripping in or out of hole to ascertain whether the drilling fluid volume matches pipe displacement. The trip tank can also be used to measure volumes gained or lost in the annulus. The pit volume measuring and recording devices on the rig should be capable of automatically transmitting pneumatic or electric signals from sensors mounted on the drilling fluid pits to recorders and signaling devices on the rig floor such that pit volume gain or loss can be detected [4, 6, 9]. A Pit Volume Totalizer system meets these requirements on conventional drilling rigs. It is a centralized processor into which signals from sensors are fed. Flow into the wellbore is monitored using a mechanical or proximity type mud pump stroke counter while the rate of returns from the wellbore is monitored via a paddle flow type sensor placed in an open flowline. The level in the mud pits can be monitored using a mud level probe or an ultrasonic-type level sensor which can account for solids build up at the bottom of the tank that may affect float type readings [6].

These measurements, that aid in kick detection, are frequently monitored at the driller's console and corroborated by the mud logger's monitoring system. The conventional kick detection system is designed to raise alarms based primarily on threshold readings of delta flow (the difference between inlet and outlet flow rates) and pit gain over time. Mathematically, the delta flow method is represented thus:

$$\Delta Q = Q_i - Q_o \tag{1}$$

where; $\Delta Q > 0$ indicates lost circulation; and $\Delta Q < 0$ indicates that a kick has occurred [11]. The drilling crew should be able to recognize a kick volume of 5 bbl (0.795 m^3) or less during trips while a kick volume of 10 bbl (1.590 m^3) or less should be recognized while drilling. A flow check is performed if improper hole fill up is noticed during a trip as measured by the trip tank. If the flow check is positive the well should be shut in, conversely, the drill string should be run back to the bottom and the well circulated bottoms up [4, 9].

3.3 Auxiliary drilling rig equipment for kick detection

Mud logging as a service is typically provided under Surface Logging Services which involves the use surface measurements to infer formation and wellbore properties. Real time monitoring of data obtainable through mud logging provides several parameters for kick detection which include increase in pit volume (pit gain), pump rate, return flow rate, rate of penetration (ROP), total gas, connection gas and drop in pump pressure. None of these parameters requires sophisticated downhole electronics or advanced signal processing. These parameters can be categorized into instantaneous parameters (drilling parameters) and lagged parameters. The drilling parameters are ROP, pit gain, pump pressure, pump rate and return flow rate. The lagged parameters, on the other hand, comprise gas parameters delayed by the lag time. Lag time, a definite time interval that is always required for pumping the drilled formation cuttings and drilling fluid from the hole bottom to the surface, depends on both the volume of drilling fluid in the annulus and the flow rate at which the drilling fluid is circulated. Correlating the frequency and level of the connection gas with respect to the mud weight can give an accurate indication of differential pressure and thus indicate near-balance or underbalanced drilling. With the pumps off, the equivalent circulating density decreases to the static drilling fluid weight. The connection gas, as an indicator of underbalanced situation, reflects as sharp peaks on the mud log. This is contrasted to total gas readings which increase in a smooth fashion due to drilling through a gas formation without corresponding increase in pore pressure. The lag time of the gas peak due to connection gas would be relative to when pumps are off. Hence, human interpretation (provided by the mud logging engineer or mud logger) is required to continuously monitor and analyze acquired parameters for decisive actions to prevent or mitigate a well control incident [12–14].

3.4 Limitations of conventional kick detection systems

While these traditional monitoring systems for kick detection are somewhat reliable, their response time is somewhat slow and thus potentially aggravate the initial problem of the gas influx in some scenarios. An overview of loss of well control (LOWC) events that occurred after the BOP had been landed on the wellhead in the US Gulf of Mexico (Outer Continental Shelf) between 2011 and 2015 showed that kicks were not detected before the well started flowing to the surface or surrounding formations in 50% of the recorded cases. It was inferred that the LOWC events could have been prevented if the kicks had been observed early. Case studies of the Macondo blowout and the Bardolino loss of well control event further emphasize the importance of an efficient and adaptable early kick detection system. The Macondo accident resulted in the loss of 11 lives, the release of 680,000 m^3 (4,250,000 bbls) of crude oil in 85 days to the environment, billions of dollars in economic damages and mitigations arising from the event. The Bardolino incident, on the other hand, due to early detection of kick and proper interpretation of the signs of kick, was managed without any spill or loss of life [5, 7, 8, 15].

Gas kick detection is particularly challenging in deep offshore environments for several reasons. First, as the water depth increases, the safe drilling fluid operating window between the fracture and formation pressures narrows. Secondly, relying on lagged parameters becomes increasingly unreliable with increasing depth in ultra-deep waters where bottoms-up circulation can take as much as 4 h. In event that the well kicks during this period, the kick volume increases, and the time spent waiting for the kick indicators reduces the drillers' ability to mitigate potential impact. Thirdly, the solubility of gas from the formation in non-aqueous drilling fluids under high pressure could lead to large gas volumes being dissolved in the drilling fluid until the saturation pressure is attained. Gas solubility in these drilling fluids such as oil-based systems could be as high as 100 times greater in solubility than in water-based systems. Consequently, gas remains dissolved (and largely undetected) in the drilling fluid during a kick until much lower pressures are encountered towards the surface as pit gain as compared to the bottom of the marine riser. This gas influx initially translates to undiscernible increase in pit gain until the gas is released at shallow depths which could compromise well integrity and ultimately blowout. This masking of influx gas has been found to worsen with increase in the mud flow rate. Fourthly, currents and wave motion further influence measurements on marine vessels which make early kick detection difficult. Fifthly, in subsea wells for which kicks have been detected and the well shut-in, dissolved gas could hamper subsequent circulations carried out to restore well control by blockage of choke and kill lines due to the formation of hydrates at low temperatures. [16–18]. The limitations are being addressed through more sensitive early kick detection systems.

4. Developments in early kick detection for conventional drilling

The following criteria have been set for assessing the success of a kick detection system—how early kicks are detected, how the system is able to eliminate or minimize the number of false alarms, the sensitivity and accuracy of the sensor(s), and its ease of installation [19]. An early kick detection (EKD) system has been described as a system of hardware, Intelligent Control Unit (ICU) and control software with the capability to detect an influx of formation fluids into the borehole during well operations. An advanced EKD system utilizes high precision equipment with ICU/software providing advanced models and algorithms for greater automation and comparison to controlled well conditions. As with simple EKD systems, audio and visual alarms are an integral part of any EKD system to provide real-time assessment [20]. Advances in EKD systems will be considered in terms of sensor function and sensitivity, sensor location (surface versus downhole measurement), and algorithms for efficient kick detection. Each of the previously mentioned primary kick indicators (increase in flow rate while pumping at a constant rate, pit gain and flow from the well when the pumps are off) are measured with different sensors with differing physical principles.

4.1 Surface sensors for early kick detection

Ultrasonic level sensors are preferred for measuring mud pit gain because they provide for greater sensitivity and accuracy as compared to other float meters (magnetostrictive, optical and differential pressure). They require low maintenance, and some models have a response time as low as 1 s thus very suitable for real time monitoring of the mud tank level [6, 21].

As regards flow measurement, there are two approaches: volumetric flow or mass flow measurement. The former is achieved using positive displacement flow measurements (such as pump stroke counters) or by employing flowmeters which provide estimates of velocity such as electromagnetic, turbine, ultrasonic, and vortex flowmeters [6]. Electromagnetic flowmeters installed both in the pump output and return flowlines have been used in implementing the delta flow approach for kick detection especially where there is the restriction of space [11, 13]. Electromagnetic flowmeters have the advantages of simple structure with no moving parts and no obstruction of fluid flow by throttle parts or its flow path. Therefore, there is no resultant additional pressure loss, wear, blockage, or corrosion of the inner lining due to solids-laden flow [22]. However, their applicability is limited to water-based drilling fluid [23]. It has been reported that the accuracy of electromagnetic flowmeters for early kick detection can be improved by installation in a V-shaped flowline segment on the outlet flow path as challenges with transient large flow passage and solids deposition were resolved [24].

The use of ultrasound flowmeters is an alternative to electromagnetic measurement applicable in both water-based and oil-based drilling fluid. This type of flowmeters works on the principle that part of the reflected ultrasonic waves that get transmitted into the pipe wall from drilling muds gets transferred into Lamb waves and subsequent a relationship between the reflected signal frequency and the flow rate is obtained. The method is nonintrusive but suffers from great attenuation of ultrasound waves in mud. This problem is resolved by continuous detection of non-oriented reflected ultrasound Doppler frequency shift, which relates the drilling fluid flow rate to the collected repeated Lamb waves. A related flow rate algorithm is obtained through the even distribution characteristics of the reflection angles [25]. The installation of three ultrasonic sensors in an open channel with Venturi constriction provided high accuracy flow rate measurement comparable to electromagnetic flowmeter measurements which are not susceptible to cuttings settlement at low flow velocity [23].

However, the most proven meter for EKD is the Coriolis flowmeter: this is based on the mass flow measurement principle. It can provide mass flow rate, density, and temperature measurements of liquids and gases within a single meter in the presence of either water-based or oil-based drilling fluid. Coriolis flowmeters provide mass flow rate measurements independent of the physical properties of the fluid and are unaffected by changes fluid properties due to fluctuations in density, viscosity, temperature, or composition. Flow measurements can be transmitted in real time so that software models are updated and EKD is achieved. In the Coriolis flowmeter a rotation force is created as the flow loop rotates about a secondary axis in response to the circulation of drilling fluid through a circular path about a primary axis. This force is directly proportional to the angular momentum of the fluid flow around the circular path (which gives a direct indication of mass flow rate) while frequency at which flow tube vibrates provides a direct measure of the fluid density. However, the flow and density measurement accuracy of the Coriolis sensor becomes degraded by entrained gas fractions exceeding 5% [5, 26]. The pressure rating limited to about 3000 psi (207 bar) precludes it use to the standpipe and the pump suction line [6, 20]. The use of the density compensated Coriolis meter is limited in precise kick detection when the mud pumps are off with no flow as is the case when making connections or tripping. Active mud circulation through the Coriolis flow meter is required for a measurement to be taken [20]. Optimal performance of the Coriolis mass flowmeter is obtained with high profile, dual-tube sensors with low tube frequency [26]. A Coriolis meter installed on a conventional rig is shown in **Figure 2**.

4.2 Smart flowback fingerprinting

Kick detection based on surface measurements especially the delta flow approach that compares the flow rate into the well and the flow rate of the returns from the well as an indicator of either an influx or loss scenario could be complicated as issues such

Figure 2.
Coriolis installation on the bell nipple of a conventional drilling rig. N.B.: The arrows indicate the bypass and flow direction through the Coriolis from bottom to top [26].

as wellbore breathing or ballooning and changing thermal conditions could mask the occurrence of a kick. Borehole ballooning or breathing occurs when slow mud losses occur during drilling ahead and a subsequent flowing of the well when the pumps are off during a connection operation or flow check. Therefore, changes in mud pit volume during a drill pipe connection are keenly monitored. This is critical because kicks frequently occur during drill pipe connections [6, 27]. To address the masking of kicks, Smart Flowback Fingerprinting was developed, a method of kick detection using an automated process to monitor wellbore flowback. It uses statistical analysis to interpret flowback data obtained during static conditions in which the rates-of-change for multiple successive drilling fluid flowback cycles to the mud pits are compared and analyzed [28]. It is expected that under static conditions, drilling fluid flowback cycles will have a repeatable profile when measured over successive cycles. Thus, any departure from the expected flowback profile could indicate a formation fluid influx. The technology enables real time detection of flowbacks exceeding normal volumes, without human intervention, with minimal false alarms depicted clearly as threshold and alarm curves. The system can accurately identify influx of formation fluids as distinguished from wellbore breathing and flowback which occurs when the well is static [28, 29].

4.3 Downhole sensors for early kick detection

The closer the location of real-time kick indicator sensors to the formation, the earlier the kick would be detected. Real-time downhole sensing alternatives for kick detection have been developed. Measurement while drilling (MWD) combined with

Logging while drilling (LWD) provides a viable alternative to surface measurements for kick detection. MWD tools are added to the drilling bottomhole assembly (BHA) to take electro-mechanical measurements while drilling, simultaneously. They are very effective in guiding the drill bit to the target pay zone, the acquisition of wellbore deviation directional surveys and the measurement of drilling mechanics data such as downhole torque, pressure, and vibration, with real time transmission of acquired data to the surface. A major MWD application that aids in kick detection is the accurate downhole BHP measurement via the Pressure While Drilling (PWD) tool using high-accuracy quartz pressure gauges. The PWD tool enables continuous annular and wellbore downhole pressure monitoring so that BHP is kept within the safe drilling window [6, 13].

LWD tools provide petrophysical data such as porosity, resistivity, density, and gamma ray. As regards kick detection, three key measurements affected by borehole fluids are density, electrical resistivity, and acoustic velocity. Bulk density as measured by the gamma density tool will decline as the drilling fluid is diluted by a gas kick. An influx of petroleum fluids will result in a clear increase in electrical resistivity in either water-based or oil-based fluids while the compressional wave velocity in drilling fluids will increase with an influx of gas. MWD/LWD tools are in-built with electronic sensors and batteries packaged in the housing in such a way that they do not impede the high flow rates that occur during drilling. However, a major drawback with using MWD/LWD tools is the requirement of a minimum fluid flow rate for signal transmission to the surface in real time. This implies that there would be no data transmission at low flow rates (a minimum of 130 gallons/min is required for some tools), during connections and when other periods when the pumps are turned off. There are other challenges with mud pulse telemetry which include the reduction in the data transmission rate with increased depth and signal attenuation in compressible drilling fluids such as OBM. While MWD/LWD sensors can measure large amounts of formation evaluation and kick detection related data, mud pulse telemetry only allows data transmission at low rates which results in a time lag between the time the mud pulse reaches the surface and when it is generated downhole. In addition, MWD/LWD tools are limited to measuring data at the bottomhole assembly (BHA) which is placed a few meters above the drill bit. These challenges limit MWD/LWD applicability for real time data transmission in ultradeep wells [6, 13].

The limitations posed by mud pulse telemetry in transmitting downhole measurements to the surface in real-time can be resolved with the Wired Drill Pipe (WDP) system. The WDP system has an embedded high strength coaxial cable and low-loss inductive coils incorporated into each joint of drill pipe during manufacture. This wired communication channel through drill pipe transfers signals at rates of about 57,000 bits/s, this is several orders of magnitude faster than is attainable via mud pulse telemetry or electromagnetic telemetry. It transmits alternating electrical signals between the BHA and the surface systems. In addition to measuring data near the drill bit and high bandwidth, WDP allows for data measurement along the entire length of the drill pipe string [5]. The use of fiber optic sensing as real-time downhole sensing option for kick detection has been proposed. Fiber optic measurements, Distributed Temperature Sensing (DTS) and Distributed Acoustic Sensing (DAS) are already in the use for injection and production flow profiling, determination of cross-flow across different zones and detection of flow behind casing in completed wells. The applicability of fiber optic sensing during drilling operations has only been tested for gas monitoring in the marine riser. The fiber optic cable is installed in a similar manner to a flexible production riser installation. Data transmission is achieved by launching an intense laser pulse into the sensing fiber which gets scattered spontaneously as it interacts with the crystalline structure in the silica-based core of a fiber optic cable which is affected by thermal and pressure variations. A fraction of the back scattered light is captured and transmitted through the fiber guided modes and propagated towards a fast photodetector. The changes in the back-scattered light can be related to the acoustic and thermal variations along the fiber with its spectrum consisting of a Rayleigh band, Brillouin band, and Raman band which are used in DTS, DAS and Distributed Strain Sensing. Once the propagation time of a pulse at a particular wavelength is known along a fiber of specific refractive index, the position of the interaction can be located and the perturbation in the measure quantity on the fiber determined [16].

4.4 The use of numerical modeling and machine learning to aid early kick detection

Flow modeling and simulation is critical for testing and validating early kick detection systems. Mathematical models which account for two-dimensional and three-dimensional transient multiphase flow with due consideration to different flow regimes within the drilling assembly and the annuli, heat transfer between the surrounding formation and the wellbore, and gas solubility are required to adequately capture wellbore dynamics during a kick scenario. Numerical techniques such as Computational Fluid Dynamics, though computationally extensive, are being employed to solve these equations due to the limitations of simplified one-dimensional models and empirical models with simplified assumptions [30]. The use of flow modeling as a kick detection method has been highlighted. Wellbore flow is simulated using a "representative" hydraulic model and then compared to the projected flow rate with actual measured flow rates. Non-linear variations in fluid properties such as density, rheology, gel strength due to multiphase flow (in some cases three phase flow—gas influx, liquid flow, and cuttings transport) are difficult to accurately model thus limiting its use in early kick detection [16]. It is worth noting that most published flow models for EKD are homogeneous-type one-dimensional two-phase drift flux models due to the simplicity of calculating phase velocity and gas fraction [30].

The machine learning approach has also been utilized for kick detection. Data employed has been obtained from different sensors on either actual drilling rigs or lab-scale experiments. Different input parameters have been tested which include majorly prior highlighted primary and secondary kick indicators. Different models have been tested such as Bayesian classifier, decision tree, k-nearest neighbor, random forest, support vector machine, different neural networks, and autoregressive models [31, 32]. Extensive gas-kick datasets were generated autonomously via 108 tests from a pilot-scale test well experimental setup equipped with a complete drilling system and a comprehensive mud logging system for surface monitoring of relevant drilling and geological parameters complimented with Doppler wave sensors just above the BOP for riser monitoring of gas migration and downhole pressure monitoring via pressure gauges. A managed pressure drilling system was coupled to the rig setup with a gas injection system. A polycrystalline diamond compact drilling bit with a bottomhole assembly was used to drill autonomously through a synthetic rock sample. The experimental setup was designed to simulate an actual gas-kick incident that occurred at approximately 4100 m (13,452 ft) during a drilling operation with a water depth of approximately 1000 m (3281 ft). Data preparation and analysis was performed which included raw-data exploration, data cleaning, signal/noise-ratio analysis, feature scaling, outlier removal, and feature selection using a random forest algorithm which resulted in reduction from the initial 24 parameters to 11 parameters considered important for kick detection. Four parameters (ROP, BHP, Doppler amplitude, and differential flow out capturing delta flow) were considered of utmost importance in early kick detection. The data was further labeled using a six-level risk likelihood criterion instead of the typical two-state alarms ("kick" or "no kick"). The splitting ratio for time-series dataset was 63%, 7%, and 30% among the training, validating, and testing sets, respectively. Of the four machine learning algorithms tested, decision tree, *k*-nearest neighbors, support vector machine, and long short-term memory (LSTM), the LSTM recurrent neural network algorithm showed the best performance, with early detect gas kicks and proper classification into the six kick alarm levels with minimal false negatives. The maximum detection time delay was 7 s only, which provides sufficient time margin to address the gas kick scenarios. The value in supplementing surface kick detection related parameters with continuous Doppler-ultrasonic-wave parameters measured at the mudline and downhole BHP was demonstrated [33].

5. Early kick detection and automatic control in managed pressure drilling

The need for early kick detection systems is further underscored in the implementation of Managed Pressure Drilling (MPD); an adaptive drilling process that enables fast and precise control of the annular pressure profile throughout the wellbore during drilling and completion operations. The accurate monitoring of flow and pressure conditions in the well is achieved due to the closed-loop circulation system (as compared to conventional drilling with an open annulus). Influx and loss situations are detected earlier in systems where MPD is employed as compared to conventional drilling. With MPD the safety of personnel onboard the rig is enhanced since a gas kick circulated with drilling fluid to the surface through the mud-gas separator without either reducing the BHP or stopping the pumps. The risk of sticking pipe is reduced as a kick can be handled without rotating the pipe [34]. Any influx into the wellbore during MPD will be safely contained to avoid continuous influx of formation fluids. Thus, the emergency well control requirements may not be required as the MPD system is set up for its occurrence. MPD has found wide applicability in projects with technical complexity and narrow pressure windows thus enabling the continuation of operations which would have been adjudged unfeasible [35]. The application this technology (MPD) has been shown to achieve automated dynamic well control as well as reduced non-productive time by allowing influx circulation at full rate. It removes human factors intrinsic in conventional well control and the need for flow check, making the need for shutting in the well and consequently the use of the BOP optional [36].

There are three fundamentally different MPD variants implemented based on the operating conditions with different objectives regarding pressure control and influx management. First, Constant Bottomhole Pressure (CBHP) method, BHP is controlled by continuous automatic adjusting of the choke to track the pre-defined pressure profile to eliminate any kick or fluid loss in a relatively unknown and narrow drilling margin. Then, the Dual Gradient Drilling method is used in offshore operations where the return mud does not travel through a large diameter drilling riser as the method reduces the number of casings required. The pressure gradient below the mudline is isolated from the drilling mud gradient above removing the impact of the water depth on the drilling operations. Third, the Pressurized Mud Cap Drilling method entails the use of a sacrificial fluid like water to manage the mud losses in the highly depleted formation. Of these three MPD variants, the CBHP is the most common variant adopted for drilling in deep offshore environments [14]. The implementation of MPD systems can be considered based on the control parameter such as surface backpressure (SBP), fluid density, fluid rheology, annular fluid level, circulating friction and hole geometry of which SBP is the most used control parameter [34].

MPD-CBHP is typically achieved through a rotating control device (RCD) installed on the surface or subsea BOP to seal the annulus from the atmosphere and closing around the drill pipe. The returns from the well are diverted from the rig floor through a choke manifold while allowing for both pipe rotation and reciprocation. Thus, tripping and drilling operations can be performed while the returns are diverted through the choke manifold. The SBP which is propagated throughout the annulus is used to control the BHP to a desired setpoint by manipulation of the choke openings [34, 35, 37]. The MPD choke manifold is installed separately in parallel with the rigs main flow line and the conventional rig choke manifold. This set-up makes allowance for circulations through the MPD manifold and circulations by conventional methods [35]. The RCD is not considered as a well barrier as regards well control operations [38]. In floating drilling rigs, the RCD is installed below the slip joint with flow diverted through flexible lines to the return system. With this setup, the effect of the rig heave on the circulating volume in the riser is canceled, thus, this remains [5]. The automated choke manifold is run on control systems with a programmable logic controller which could be set to control the valve percentage opening and closing. In addition, the automated choke manifold is connected to auxiliary mud or nitrogen pump to provide the surface back pressure (SBP), as well as monitor flow rates in and out of the wellbore [38]. MPD systems also includes a backpressure pump, flowmeter, and software algorithm. The equipment layout depends on whether the system is manual requiring an operator to control annular pressure via opening and closing of the choke valve, semi-automatic for which the choke is automatically adjusted to obtain the predetermined surface pressure using hydraulics software and automatic requiring a PLC which is programmed with hydraulics software connected to the choke and the backpressure pump that controls the desired annular pressure automatically [5]. A MPD system is illustrated in **Figure 3**.

This dynamic well control method (MPD) is only applicable for influxes up to a certain volume as the kick tolerance (the maximum influx volume that can be handled and safely circulated out of the well) could be as low as 10 bbl (1.590 m^3) in some deep offshore wells. This necessitates early kick detection via flow measurements. In general, MPD systems provide EKD by using comparison of flow out (return flow) to flow in as a primary kick indicator i.e., delta flow. Coriolis flowmeters are applied for precise monitoring of both flow into the wellbore and flow out with high accuracy. Early gas detection can be achieved by monitoring the annular pressure along the wellbore with pressure sensors mounted at different depths and transmitted via WDP. Replicator stations are used for boosting the pressure signals transmitted along the WDP [5, 35]. A Venturi channel is typically used after the choke controller before the return flow line for flow out measurements towards EKD [39].

Although the level of automation in the different MPD systems varies, an automated response can be initiated to a kick scenario with a fully automated choke that includes a kick detection algorithm. When the MPD system automatically detects an influx, it can respond by increasing the backpressure which actively increases the BHP, accelerating the end of the influx cessation over a passive shut-in response.

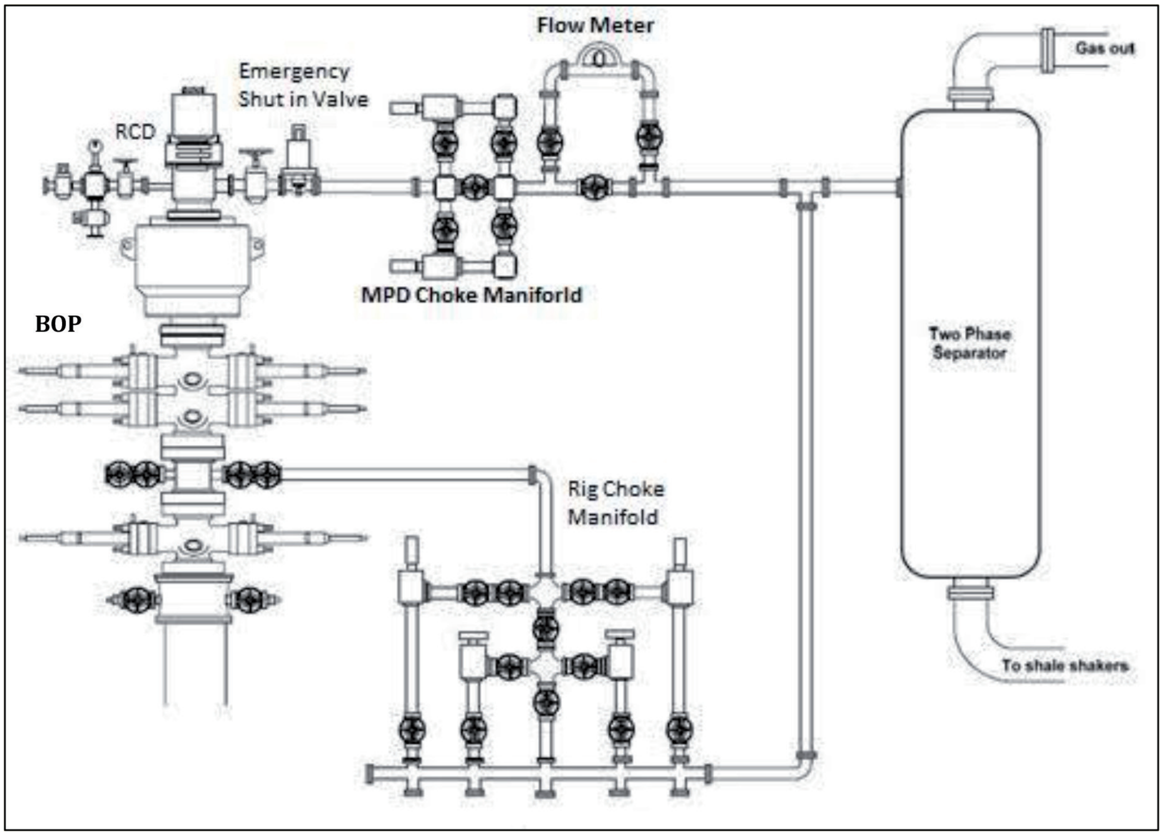

Figure 3.
A schematic of a MPD system [27].

In this way, an automated MPD system can reduce kick severity by increasing kick detection resolution thereby reducing inflow time and consequently volume, continual circulation during initial response, maintaining annular friction and preventing a decline in BHP thereby minimizing influx flow rate and volume, and increasing the BHP through active choke manipulation thereby reducing the time to end of influx and overall kick volume. This system provides real time comparison to modeled controlled conditions and automated well control response and signals the driller for necessary actions when specified thresholds are exceeded [6].

The design of pressure control systems for MPD drilling operations requires accurate modeling of the system hydraulics. However, accurate modeling of drilling systems implies to use of highly complex models involving parameterized, nonlinear, nonconservative hyperbolic Partial Differential Equations (PDEs) completed by nonlinear and implicit boundary conditions. These model features render its numerical simulation computationally expensive and make the controller design cumbersome. Model order reduction techniques have been proposed for the construction of models that combine reduced complexity with high predictive capacity. A reduced bias method capable of handling localized nonlinearities has been applied for the modeling of well dynamics under MPD [40]. An alternate approach, the use of real-time high fidelity flow modeling approximates the results of offline complex PDEs but relaxes the model accuracy during the transient phases by assuming a fixed temperature profile and the linear Bingham Plastic model [41]. These hydraulic models are implemented in the controller. Model-predictive control (MPC) techniques which utilize knowledge about the wellbore dynamics and monitored parameters on the rig to compensate for measured changes are adjudged the most appropriate for

MPD operations. MPC techniques have been found superior to simple Proportional-Integral-Derivative controllers [34]. Proper tuning of the automated MPD control systems is necessary to minimize challenge of instability of a non-robust control system of which oscillating choke position is a sign [6]. The difficulty in handling flow-in changes with high precision is also addressed by a robust MPC system [34]. Automated control during MPD is achieved by implementing reduced order high fidelity flow models within an optimal MPC framework.

6. Automated well control for conventional drilling operations

Traditionally, well control is a manual safety critical process with reliance on the driller to shut-in the well once an influx is detected. It requires high cognitive workload from the driller who is also saddled with repetitive well construction tasks for extended periods. The driller is the member of the drilling rig crew responsible for operating drilling rig equipment on the rig floor. While the capacity and preparedness of the driller is enhanced by regular training and drills, unforeseen events can unsettle him; thus, making him vulnerable to error. The driller could also be distracted by extraneous factors which could adversely impact on his performance. The role of human errors in the occurrence of LOWC events has been considered crucial as 42% of published incidents between 2014 and 2021 were attributed to human factors [42]. This encompasses the skill of the drilling personnel in recognizing a well control situation and restoring well control. It has been noted that undue reliance on human intervention in well control situations could be dangerous. Thus, organizational, and human failures could be eliminated by increasing the level of automation in well control. Automating processes allows well operations to be more reliable and consistent, effectively improving the performance of drillers. Consequently, the implementation of automation within the well control envelope is expected to contribute significantly to enhance safety and efficiency. Even though full automation of the well control process is yet to be adopted within the industry, there are technological developments towards bridging this gap [5, 6, 42].

A system, known as Automated Well Control (AWC), which fully automates kick detection and shut-in sequences during drilling operations has been developed by Safe Influx. This system enables continuous real-time monitoring of the well and manages influx flow automatically by ensuring fast identification of the influx of formation fluids into the wellbore and rapid response via immediate decision-making; thus, ensuring the influx size is minimized and the risk to people and the environment mitigated [42]. This system is classified to be on level 2 according to the automotive automation classification [42, 43]. The topology of the AWC system is shown in **Figure 4**. The well control process is automated such that once a kick is detected, the AWC system will actively control the drilling rig by performing a series of commands. Firstly, the drill string is spaced out such that an incompatible pipe connection across the BOP valve to be actuated is moved to facilitate safely shutting in the BOP. Secondly, the top drive is stopped, and the rig pumps shut down. Thirdly, the BOP is shut-in [44]. The system footprint of the automated control system on the drilling rig is a Programmable Logic Controller (PLC) and a Human Machine Interface (HMI) screen. The HMI screen can be incorporated into the rig's existing HMI screen for ease of operation by the driller. The PLC uses control algorithms to accurately monitor the parameters from the existing sensor package and control the existing rig equipment [45].

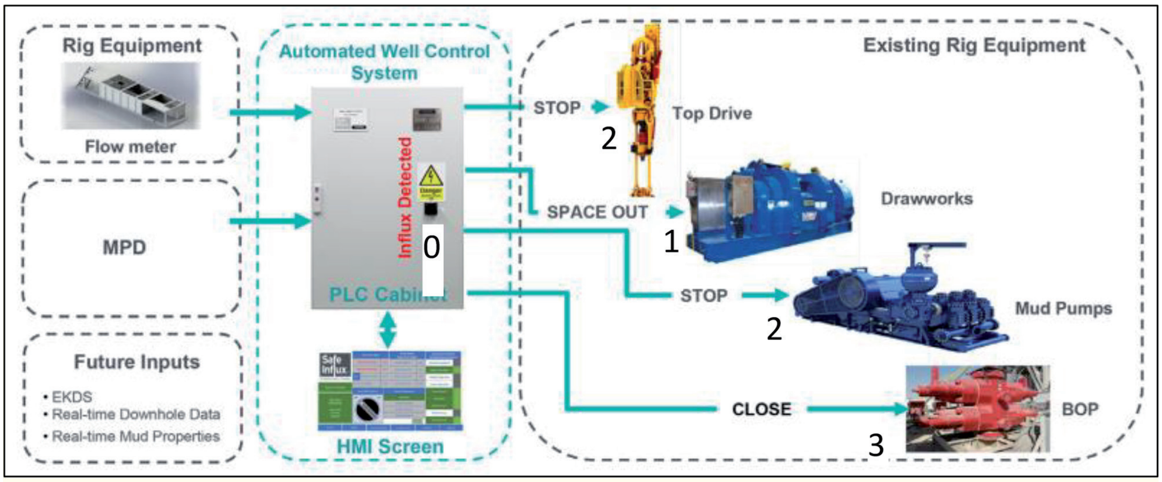

Figure 4.
The AWC system topology [45]. N.B.: The automated steps are numbered.

The space out of the drill string following kick detection is not trivial. A Well Control Space Out technology for this purpose has been developed. The technology comprises of an internet-of-things environment that links cameras and an edge server which implements deep-learning models for the real-time processing of video images recording the drill string above the drill floor. Automatic object detection is used to keep track of tool joints relative to known BOP dimensions; while video analysis of the recording is displayed on a dashboard detailing the state and steps to be followed in a well control incident without the need for any time-consuming, manual calculations. A regional convolutional neural network is used for image classification. This technology, which ensures that the BOP valve is not closed across a tool joint, is a key component towards the implementation of an automated closed-loop control system [3]. The technology is represented with a schematic in **Figure 5**.

Once the AWC system has been installed and tested, the driller is required to configure certain parameters prior to commencement of drilling operations. This includes the setup of space out parameters and the selection of the equipment whose control will be ceded to AWC system such as the top drive, mud pumps, drawworks, and BOP. This ensures that the Operator or Drilling Contractor policy can be implemented, so that the Operator and Drilling Contractor can be assured that for the duration of the well a robust assurance process is in place for well control [44]. In the case of an influx of formation fluids, the driller is alerted both visually and audibly at the HMI by the system, indicating that the AWC sequence has commenced. The system then takes control of the prior specified equipment that the human operator would have operated to regain well control [42].

The AWC system has been extensively tested on drilling simulators to verify how the system functioned in a wide range of scenarios. The system was also put to test at a well control training event involving a large group of drillers. Each driller performed a manual shut in on a particular well programmed into a well control simulator. Even though each driller had prior knowledge of an impending kick, the smallest influx volume shut-in by the drillers ranged from 1.27 m^3 (7.99 bbl) to 5.08 m^3 (31.96 bbl), with the typical volume being about 3 m^3 (18.87 bbl). When the Automated Well Control system was activated to automatically shut-in the same influx volume, the shut-in volume was under 0.32 m^3 (2.02 bbl), an order of magnitude less than any human driller achieved [42].

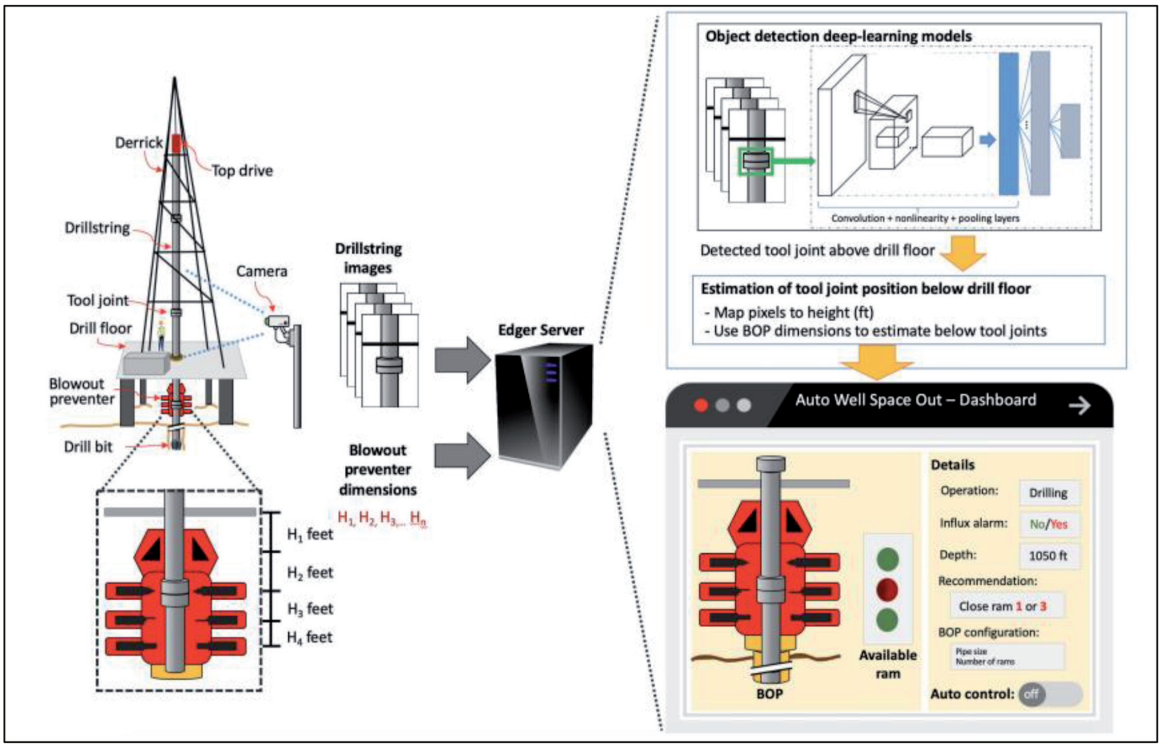

Figure 5.
The well control space out technology illustrated [3].

A full field trial of the was successfully conducted in Aberdeen, UK, where the minimum viable product of the AWC system was interfaced with a conventional land rig for the purpose of demonstrating automated well control. A series of 20 different tests were performed to test full functionality during normal drilling ahead operations and the effects of incorrect set up. The AWC system proved its functionality of the standard system under the different scenarios and operational requirements tested. Furthermore, the AWC system has been interfaced successfully with a MPD system. This integration of both systems provides automated primary and secondary well control, which allow wells to be drilled and constructed with a very high level of efficiency and integrity [46]. The AWC system is currently designed for the drilling phase with certification to operate on either a cyber-rig or a traditional rig [42].

7. Conclusion

The deployment of EKD systems has become imperative for executing drilling and completion operations in deep offshore environments which are prone to LOWC incidents to prevent the dire consequences of past accidents. The Coriolis mass flowmeter is integral to EKD systems for accurate differential flow measurements. Other meters such as electromagnetic flowmeters and Venturi channels with ultrasonic sensors are used when operational constraints limit the use of Coriolis mass flowmeters. Downhole monitoring, along the marine riser down to the mudline via ultrasonic Doppler sensors transmitted via optical fiber and near the drill bit through pressure while drilling, has proven valuable in complementing surface measurements in achieving EKD. Smart fingerprinting using machine learning algorithms help in minimizing false alarms which could arise due to well breathing and ballooning when the pumps are off. Automation in well control can be achieved for conventional overbalance drilling operations by coupling an AWC system to the drilling rig for fast well shut-in or through automated CBHP-MPD for a closed annulus. For future well projects with high LOWC risks, EKD with AWC whether for an open or closed annulus should be incorporated into the well program prior to well construction to ensure safe project delivery.

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Conflict of interest

The authors declare no conflict of interest.

Nomenclature

AWC	Automated Well Control
BHA	Bottomhole Assembly
BHP	Bottomhole Pressure
BOP	Blowout Preventer
CBHP	Constant Bottomhole Pressure
DAS	Distributed Acoustic Sensing
DTS	Distributed Temperature Sensing
EKD	Early Kick Detection
HMI	Human Machine Interface
ICU	Intelligent Control Unit
LOWC	Loss of Well Control
LSTM	Long Short-Term Memory
LWD	Logging while Drilling
MPC	Model-Predictive Control
MPD	Managed Pressure Drilling
MWD	Measurement while Drilling
PDE	Partial Differential Equation
PLC	Programmable Logic Controller
PWD	Pressure while Drilling
RCD	Rotating Control Device
ROP	Rate of Penetration
SBP	Surface Backpressure
SCSSV	Surface-Controlled Subsurface Safety Valve
WDP	Wired Drill Pipe

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